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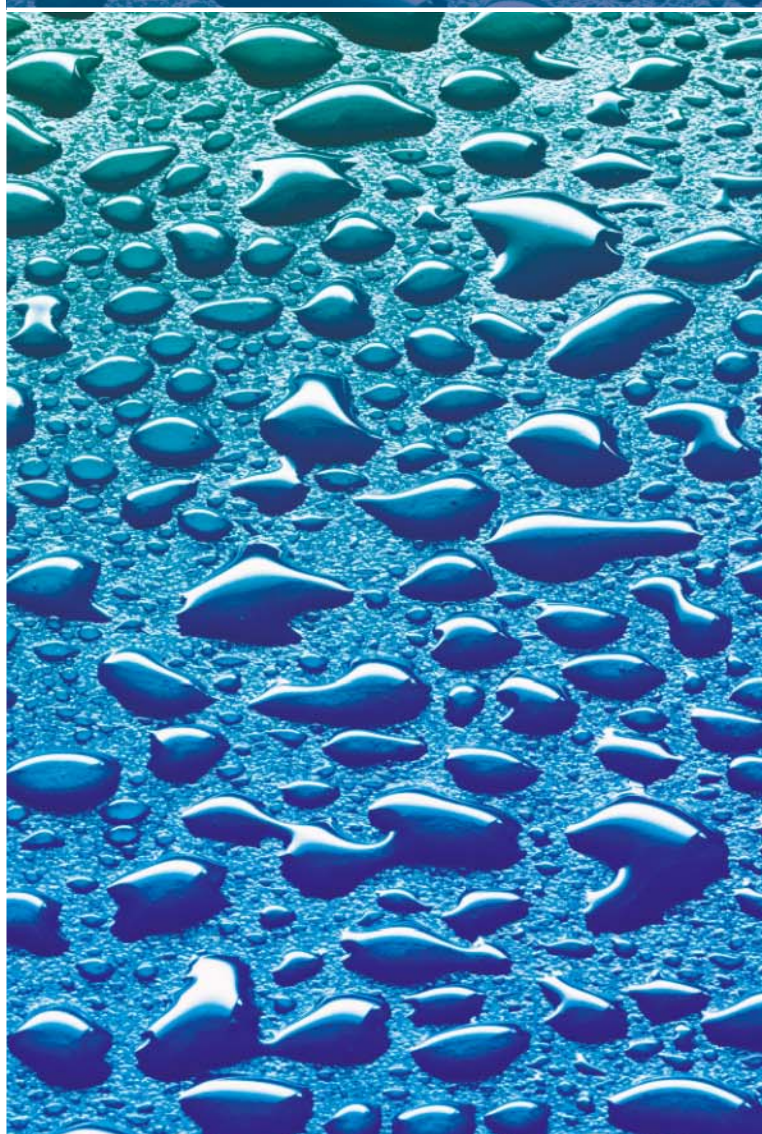
Energy Technology Analysis



PROSPECTS FOR HYDROGEN AND FUEL CELLS

OECD

INTERNATIONAL ENERGY AGENCY

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- 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.

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FOREWORD

Oil and gas supply security and climate change continue to represent prominent challenges for all countries. They are particularly pressing in the transportation sector, which still relies almost exclusively on oil. Reducing the dependence on hydrocarbons and the emissions of carbon dioxide (CO_2) is becoming increasingly urgent. This will require significant changes in the global energy system and the introduction of new technologies which are able to produce and use energy more efficiently and cleanly than in the past.

Recently, IEA countries have invested considerable efforts in making commercially available technologies to separate and store carbon dioxide from fossil fuels, produce hydrogen from fossil, nuclear and renewable energy sources, and develop fuel cells for clean and efficient use of hydrogen and other fuels. In addition to reducing emissions in power generation, CO_2 capture and storage would enable hydrogen to be produced from natural gas and from the world's abundant coal reserves without incurring significant emissions to the atmosphere. Clean, CO_2-free hydrogen produced from fossil fuels and – in the longer term – from nuclear and renewable sources could potentially replace oil and reduce emissions in transport. In turn, fuel cells hold the promise to significantly increase the efficiency of the energy system in both stationary and transport applications with reduced or nearly zero emissions.

Hydrogen and fuel cells comprise a complex array of technologies and processes for hydrogen production, storage, transportation, distribution, fuel cell concepts and other end-use technologies. Some of these technologies are still under development and surrounded by considerable uncertainty. Realistic assessments and policy strategies for hydrogen and fuel cells must consider the complexity of the overall system, the uncertainties, the peculiarities of each single technology, the role of the competing options, and not least the impact that energy policies may have on new technologies to gain market share.

Using hydrogen as an energy carrier requires key technology breakthroughs and decisive cost reduction in all domains of the energy chain (production, distribution, storage, fuel cells). Concerted government policies, international co-operation and public R&D investment are also indispensable for catalysing larger private investment, achieving commercial maturity, building infrastructure and public awareness, and fostering the penetration of hydrogen and fuel cells in a competitive marketplace.

"Prospects for Hydrogen and Fuel Cells" offers an authoritative and objective analysis of the hydrogen and fuel cell potential to meet the global challenges in the energy sector. Information regarding latest RD&D achievements, policies and business opportunities are assessed from the perspective of a rapidly changing global energy system in the next half century. The analysis provides a realistic assessment of technology prospects, an incisive evaluation of barriers to and scenarios for a transition to hydrogen, and guidance for far-reaching decision making under uncertainty.

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Executive Director

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Neil Hirst, Director of the IEA Energy Technology and R&D Office, supervised the work. Marianne Haug, former Director of the Office, provided leadership in conceiving the project. The study is the result of a close cooperation between the IEA Energy Technology Collaboration Division, headed by Antonio Pflüger, and the IEA Energy Technology Policy Division, headed by Robert Dixon from September 2005, by Fridtjof Unander (acting head from October 2004 to August 2005) and by Carmen Difiglio until September 2004.

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EXECUTIVE SUMMARY

Hydrogen is an energy carrier with the potential to open the door to a wide range of new energy technologies and policy options. Fuel cells powered by hydrogen or other fuels can achieve high efficiencies and have a variety of possible uses in mobile and stationary applications. In the right circumstances hydrogen and fuel cells technologies could make major contributions to the key policy objectives of energy security and mitigation of carbon dioxide (CO_2) emissions, especially in the transportation sector. Recent advances in hydrogen and fuel cell research and development have tremendously increased the interest of the international community in these technologies which have the potential to create paradigm shifts in transport and distributed power generation. There are approximately 400 demonstration projects currently in progress world wide.

Of the many technology options, the possibility of hydrogen powered fuel cell vehicles is perhaps the most far reaching. It has attracted widest interest and unprecedented research investment by Governments and private firms in the automobile and energy sectors. Replacing petrol used in vehicles could, obviously, have major advantages for energy security and climate change mitigation. And fuel cell powered vehicles could be a new, attractive market with benefits for the global economy. Hydrogen can also reduce CO_2 emissions when it is produced from renewables and nuclear energy. If the source of the hydrogen is natural gas or coal then the capture and storage of CO_2 is essential to achieve emission savings. In all cases, hydrogen fuel cell vehicles reduce local environmental pollution, as the only effluent is water vapour.

Governments, private companies, and experts have different views and expectations regarding the prospects for hydrogen and fuel cells. There is a complex array of technologies and processes for hydrogen production, storage, transportation, distribution, different types of fuel cells, and other end use technologies. There is also a range of competing technologies with the potential to meet, at least in part, some of the same policy objectives. These include biofuels, and various forms of electric or hybrid vehicles. This study has tried to take a realistic view of the potential for hydrogen taking account, also, of the potential of these other technologies.

The study was conceived in the framework of the IEA Hydrogen Co-ordination Group, established in 2003, and utilises the IEA's Energy Technology Perspectives model. The analysis draws on the IEA's extensive international energy technology network and takes account of the results of workshops involving national and private sector experts in the field, including key industry associations.

While recent technology advances have been impressive, most hydrogen technologies are currently substantially more costly than their conventional counterparts. And a transition to hydrogen would require infrastructure investment in the range of several hundred billion to a few trillion dollars, over several decades, depending on timing and assumptions as to the investment that would eventually have been needed in the alternative system.

Nevertheless, hydrogen and fuel cells may have a major role in the future energy market if current targets for reducing technology costs can be met and if governments give high priorities to reducing CO_2 emissions, to improved energy security and to research and development efforts. In the next few decades, hydrogen production costs need to be reduced 3 to 10 fold, depending on the technology used, and fuel cell costs by 10 to 50 fold. Substantial improvements are also needed to overcome key technology issues concerning fuel cells and hydrogen on-board storage for fuel cell vehicles. Governments would need to adopt policies that incentivise CO_2 emission savings by giving a value to the emissions avoided. They would also need to adopt policies to diversify the energy supply. However, policies for enhanced security on their own would not be sufficient. In the absence of CO_2 policies, there are other technologies and fuels (such as coal) that could diversify energy supply at less cost. In any case, new technologies are needed to support CO_2 and energy security policies.

The analysis suggests that if these most favourable conditions are met then 30% of the global stock of vehicles could be powered by hydrogen fuel cells by 2050 – about 700 million vehicles. The oil consumption of the same number of petrol engine vehicles would have been some 15 million barrels per day, equivalent to around 13% of global oil demand (or 5% of the global primary energy demand) in the reference scenario at the time. It is important to recognise, however, that, in the absence of hydrogen, other low carbon technologies such as biofuels and synfuels from coal and gas might also have saved much of this oil in the policy environment assumed. Because the efficiency of the hydrogen fuel cell vehicles (*e.g.* using Proton Exchange Membrane fuel cells) is more than twice that of conventional engines the total energy content of hydrogen used would be much less than this – less than 3% of the global primary energy demand.

If hydrogen used for energy applications is added to hydrogen used in refinery and chemical industry then, in this most favourable scenario, the total amount of hydrogen used in 2050 would be some 180 million tonnes of hydrogen per year, equivalent to more than a 4-fold increase in comparison with today's hydrogen use.

However, hydrogen and fuel cell vehicles will only play a significant role under these favourable assumptions. If less optimistic assumptions are considered for technology development and policy measures, hydrogen and fuel cell vehicles are unlikely to reach the critical mass that is needed for mass market uptake. Competing fuels with lower infrastructure costs, such as biofuels and synthetic fuels derived from coal and gas, would play a larger part.

Stationary fuel cells are a more robust technology option that is much less sensitive to energy policies and competing technology options. Stationary solid oxide fuel cells (SOFC) and molten carbonate fuel cells (MCFC) – mostly fuelled by natural gas – can contribute to meeting the demand for distributed combined heat and power with some 200-300 Gigawatts, equal to 2-3% of global generating capacity in 2050. Currently, private investment in stationary fuel cells and installed capacity is continuously growing.

This analysis does not take account of the possibility of major breakthroughs in some high-risk/high-potential technologies that are presently in their infancy. These include new concepts and materials for fuel cells, and on-board solid hydrogen storage and production technologies, such as photo-electrolysis, biological production, and water splitting by nuclear and solar heat. These technologies have the potential to make a tremendous impact on the future of hydrogen and fuel cells and the whole energy system. Of course, breakthroughs are also possible in competing technologies, such as electric vehicle batteries.

Conclusions and recommendations

Uncertainty indeed remains as to the mix of technologies that will play the largest parts in meeting the challenges of global warming, energy security and economic efficiency in the longer term. It is essential, therefore to continue to develop a broad portfolio. The technologies associated with hydrogen and with fuel cells are amongst those with the greatest potential, in particular, for the transport sector. Consistent with this portfolio approach, governments should, therefore, continue to sustain research, development, and demonstration programmes for hydrogen and fuel cells, with a focus on:

- Cost effective production of hydrogen that meets environmental and quality standards.
- New materials and concepts to reduce the costs and increase the durability of fuel cells.
- Reliable and economic systems for hydrogen on-board storage in fuel cell vehicles.
- Concepts and technologies for reducing the cost and the energy consumption of hydrogen transportation and distribution.
- Basic science research in areas such as photo-electrolysis, high temperature water splitting, biological production of hydrogen, new materials for hydrogen storage and fuel cells, and nanotechnologies. For this purpose it is important to retain the links between the basic and applied science communities.

Deployment of hydrogen infrastructure at this point would be premature, as some of the key technical issues that are still being worked on – such as fuel cell operating conditions and hydrogen on-board storage – may have a considerable impact on the choice of technologies for hydrogen production, distribution, and refuelling. However, continued international co-operation on R&D, infrastructure concepts, and harmonisation of codes and standards remains vital in the light of the global nature of the transport industry.

As natural gas and coal are likely to remain the lowest-cost sources of hydrogen for many years to come, large-scale CO_2 capture and storage, already of the highest importance to mitigate emission in the power sector, is also a vital step towards the wider use of hydrogen.

In the coming years, full use should be taken of niche opportunities to deploy fuel cell vehicles, for instance in public service fleets (buses, delivery vans) where the economics are more attractive than for private cars, and in situations where low-cost hydrogen is available. Such programmes can start the process of cost reduction through larger scale manufacture, can broaden operating experience, and can begin to familiarise the public with these technologies.

OVERVIEW

The role of hydrogen in the energy context

Security of energy supply, high oil prices and growing emissions of greenhouse gases continue to pose unresolved challenges for the global economy and the climate of the planet. While oil prices and supply security represent immediate or short-term issues for the global economy, the effects of climate change are a longer term challenge. Consensus exists in the international community that urgent action is needed to both face short-term energy security problems and mitigate future climate change, and that technology and policy are part of the solution.

There is no energy technology "silver bullet", however. No technology promises to hold the overall solution, and all options need to be carefully explored. Technology advances or even breakthroughs are needed in a number of domains to achieve cost-effective renewables such as photovoltaic and biomass, acceptable nuclear waste management, low-cost CO_2 capture and storage for fossil fuels and – not least – efficient energy end-uses. Hydrogen and fuel cell technologies promise considerable benefits in terms of energy security and CO_2 emissions, but also require significant technical breakthroughs, cost reduction and appropriate policies to enter the market.

Hydrogen is a gaseous, clean energy carrier. It does not occur in nature in any significant amounts but can be produced from a wide range of primary energy sources, such as coal, natural gas, nuclear and renewable energy. It could be used in almost all stationary and mobile energy applications. Recent technology advances have increased attention for the use of hydrogen and fuel cells as a substitute or complement for oil fuels and internal combustion engines in transport. Depending on the characteristics of the well-to-wheel energy chain, a transportation system based on hydrogen fuel cell vehicles (FCVs) may result in very significant reductions of oil demand and primary energy use. Of course, the largest benefit in terms of supply security is obtained if hydrogen is produced from coal, renewable or nuclear primary energy.

In principle, a hydrogen-based energy system would not generate any significant emissions of greenhouse gases. If hydrogen is used in fuel cells or burned with pure oxygen in combustion processes, it only produces water as a combustion product. Viewed as a whole, the emissions of a hydrogen-based energy system depend on the fuel chain characteristics, primarily the energy source that is used to produce hydrogen and the production process. Hydrogen is a nearly CO_2-free energy carrier if produced directly from renewable and nuclear energy, or from natural gas and coal with CO_2 capture and storage. If hydrogen is produced by water electrolysis, the emissions will depend on the upstream process to produce electricity. As CO_2 capture and storage technology is still under development and the availability of renewable or nuclear electricity is limited in most regions, the potential for producing CO_2-free hydrogen is currently limited, and in the future will depend on the development of these technologies.

Using hydrogen in fuel cells maximizes the efficiency and emissions-reduction benefits in both transport and stationary applications. Therefore, most emphasis in this study focuses on hydrogen use in fuel cells. However, hydrogen and fuel cells are not necessarily linked together. Certain fuel cells can use fuels other than hydrogen, and hydrogen can be burned in conventional combustion engines and turbines with limited technical changes. These applications, however, do not provide similar substantial benefits for emissions mitigation or efficiency gains.

The infrastructure for hydrogen production, transportation, distribution and storage plays an important role for the potential of hydrogen as an energy carrier. Because of the low gas density and permeability into materials, hydrogen transportation via pipeline is much more expensive in terms of investment cost and energy consumption than the transportation of natural gas. In general, transportation of gaseous or liquid hydrogen is a costly and energy-consuming process. Hydrogen storage also requires energy-intensive compression at very high pressure (350-700 bar) or liquefaction at very low temperature (–253°C) to minimize the storage space. On-board storage in solid materials for hydrogen-fuelled vehicles is a high-potential option that still is under development.

Hydrogen is widely used today for chemical and refinery processes. The amount of hydrogen that is produced today, some 5 EJ per year mainly from natural gas, is equal to more than 1% of global primary energy use. This indicates that large-scale hydrogen production is an established technology. However, using hydrogen for fuel cell vehicles or for distributed power generation requires cheaper production technologies (ideally with no CO_2 emissions), cost-effective transportation and storage technologies, and low-cost, efficient fuel cells. Depending on the production technology, hydrogen production cost should be reduced by a factor of 3 to 10, while the cost of fuel cells needs to be reduced by at least a factor of 10 to 50, in comparison with current cost estimates. Technology learning is the key to achieving these targets. Technology improvements should be associated with large-scale industrial production and economies of scale to achieve competitive costs. In the meantime, governments should foster infrastructure investment, work to establish codes and standards, and enact appropriate policies for the market introduction of hydrogen and fuel cells.

In recent years, hydrogen and fuel cells have received increasing attention and research, development and demonstration (RD&D) funds. The expectation is that a few decades from now, fuel cells and CO_2-free hydrogen (from fossil, renewable and nuclear primary energy sources) could be gaining a significant share in the transport, stationary applications and power generation markets. The OECD member countries have recently intensified their efforts on hydrogen and fuel cells RD&D. Total public spending in the OECD in 2004 amounted to some USD 1 billion and represented some 12% of all public energy RD&D spending. Even larger is the total investment of the private sector, including major oil companies, auto and truck manufacturers and a number of potentially new players in a future hydrogen and fuel cell market.

Countries that are closely involved in hydrogen and fuel cells development have set specific RD&D and deployment targets. The European Union envisages hydrogen representing 5% of the total transportation fuels by 2020 and a significant penetration of fuel cells for combined heat and power (CHP) applications in the residential and industrial sectors. With some 30 fuel cell buses running in several European cities, the European CUTE-ECTOS project is perhaps one of the most important demonstration projects world wide. In Japan, a joint public/private programme aims to commercialise 5 million fuel cell vehicles and 10 GW of stationary fuel cells by 2020. Current demonstration projects include some 60 FCVs, 10 hydrogen refuelling stations, and numerous stationary fuel cells installed in 33 different locations. In the United States, the Department of Energy (US-DOE) envisions a phased transition to hydrogen with a commercialisation decision in 2015. This will be based on the achievement of specific R&D and demonstration targets such as cost-effective hydrogen production and storage in comparison to gasoline, fuel cell engines for vehicles at less than USD 50/kW to compete with conventional vehicles, and stationary fuel cell power systems with appropriate durability at USD 400-700/kW. While the full extent of hydrogen benefits will be available in the long term, achieving these targets by 2015 would enable industry to move towards the commercialisation of the hydrogen technologies.

The interest in hydrogen is not limited to OECD countries. Brazil, China, India, and Russia are also committed to hydrogen and fuel cells development. China is aiming to trial hydrogen fuel cell buses in a demonstration project at the Beijing Olympic Games in 2008 and to initiate mass production of fuel cell vehicles from 2010 onward.

This study

Building on selected assumptions for the future developments and costs of relevant technologies, this study offers a quantitative assessment of the possible role of hydrogen and fuel cells in the energy scenarios over the coming decades. It quantifies the costs, benefits, and policy needs associated with the use of hydrogen and fuel cells. The study focuses on three principal objectives:

- Quantifying the prospects for technical improvement and cost reduction in hydrogen and fuel cell technologies.
- Exploring the technical, economic and policy issues important to a transition to a hydrogen energy system.
- Analysing the long-term perspectives of a fully developed market for hydrogen and fuel cells, and their impact on emissions and energy security.

To assess the real prospects for hydrogen and fuel cells in a competitive market, a significant emphasis is put on the potential of competing technology options. Sensitivity and scenario analysis helps to map key uncertainties that must be considered in decision making.

The study has been carried out using the IEA Energy Technology Perspectives (ETP) model, a MARKAL model of the global energy system that is used to analyse technology policies and support decision-making in the energy sector. The model includes 15 world regions with energy trading between them. There is a detailed description of the energy system with energy demand, fuels and carriers, and a database of more than 1500 demand and supply technologies. For each technology, the model has data on performance, costs, emissions, and a proper characterisation of technology learning for emerging technologies. Given the current energy systems and technology mix, the model analyses their evolution over a time horizon to 2050 and provides cost-optimal configurations under selected assumptions for energy policies and technology development.

The present study was conceived within the context of the activities of the IEA Hydrogen Co-ordination Group (HCG) and is supported by ten HCG countries, namely Australia, Austria, Canada, France, Germany, Japan, the Netherlands, Spain, the United Kingdom, and the United States.

This report consists of two parts. The first part (Chapters 1, 2, 3 and 4) offers an insight into the current status and potential development (performance and costs) of hydrogen and fuel cells technologies and competing options. The second part (Chapters 5, 6, 7 and 8) discusses how technology advances, energy policies, and other key drivers may foster the introduction of these technologies in the energy market. Their impact on CO_2 emissions and the security of energy supply, as well as R&D directions and infrastructure development, are also discussed.

Technology insights

Hydrogen

Some 40 million tonnes of gaseous hydrogen a year are currently produced via established technologies, primarily natural gas reforming but also coal gasification and water electrolysis.

However, to produce cost-effective hydrogen for energy use, these technologies need higher efficiencies, significant cost reduction and the development of cheap and safe techniques for CO_2 capture and storage. Research and development efforts focus on high-efficiency natural gas reforming, coal gasification in integrated gasifier combined cycle (IGCC) plants for the co-production of electricity and hydrogen, and electrolysis at high temperature and pressure. A number of other emerging technologies such as water splitting using solar and nuclear heat, biomass gasification, and photo-biological processes are also being developed. With different level of development, these new technologies are still far away from being commercialised.

Most current RD&D focuses on small-scale, decentralised natural gas reforming (without CO_2 capture) and electrolysis. Decentralised technologies do not require costly infrastructure for hydrogen transportation and distribution. They are therefore the best choice to produce hydrogen in the early market introduction phase. However, decentralised technologies are generally not very efficient and need substantial cost reduction to become competitive. A fundamental disadvantage of small-scale natural gas reforming is that the capture of CO_2 emissions in small plants is difficult and expensive, and therefore likely to be impractical. As far as electrolysis is concerned, current and projected costs are higher than those for natural gas reforming. It should also be noted that surplus renewable electricity for hydrogen production will probably be limited to a few regions.

The current cost of decentralized hydrogen production may exceed USD 50/GJ H_2, but various production options promise hydrogen at USD 10–15/GJ H_2. While sensitive to natural gas and electricity prices, the cost of natural gas reforming may be reduced to below USD 15/GJ H_2 by 2030 and that of electrolysis to below USD 20/GJ H_2. Even lower – below USD 10/GJ H_2 – could be the projected cost of hydrogen from centralised coal-gasification in IGCC plants with CO_2 capture and storage. The long-term costs for high temperature water splitting could be USD 10/GJ H_2 using nuclear heat and USD 20/GJ H_2 using solar heat. Higher costs are projected for other technologies. However, the lower the level of technology maturity, the higher is the uncertainty on projected production costs.

Hydrogen can fuel combustion engines and turbines, but it offers its full benefits in terms of efficiency, lower CO_2 and other pollutant emissions when used in fuel cells. Significantly, the use of hydrogen fuel cell vehicles could solve at one stroke the problems of oil-dependence and emissions in the transport sector. The stationary use of hydrogen fuel cells for combined heat and power production is also a potential application, but non-hydrogen fuel cells appear as a competitive option in this market segment.

Hydrogen on-board storage is a key issue for fuel cell vehicles, as on-board hydrogen production via reforming of fossil fuels has proved to be difficult, so far. While significant studies have focussed on hydrogen storage, existing on-board storage options do not meet the technical (compactness, drive-range) and economic requirements to make them competitive. Gaseous storage at 350-700 bar and liquid storage at –253°C are commercially available but costly options. The cost of the tank is around USD 600 to 800/kg H_2 and the electrical energy required for compression and liquefaction is more than 12% and 35% of the hydrogen energy content, respectively. 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 been confirmed by recent studies. Without further breakthroughs, gaseous storage at 700 bar seems, at present, to be the technology of choice for passenger cars. However, such a system would not meet the required targets for drive-range and costs. The global character of the car industry requires that hydrogen quality and safety standards, as well as on-board storage technologies, be established before a full-scale development of the hydrogen infrastructure begins. In particular, the on-board storage system may have a significant impact (*e.g.* hydrogen pressure) on the optimal choice for the hydrogen infrastructure (production, distribution and refuelling). Therefore, the identification of a suitable and cost-effective storage technology is an urgent issue if hydrogen is to be brought to the market.

In the case of centralized hydrogen production, the transportation and distribution costs – and the refuelling cost for transport vehicles – add considerably to the total hydrogen supply cost. These costs range from USD 5 to 10/GJ H_2 for large-scale supply systems. They may be even higher during the initial development phase. Hydrogen transportation by pipeline seems to be the lowest-cost option to move hydrogen. However, because of the low gas density and highly permeable nature of hydrogen through materials, hydrogen pipelines are twice as expensive in terms of investment cost and require five times more energy to operate, if compared to natural gas pipelines. Considerably more expensive is the transportation and distribution of liquid hydrogen.

Estimating the global investment required to develop a hydrogen infrastructure is a difficult exercise. Whether current natural gas pipelines may be used to transport hydrogen is still matter of discussion. Certainly, some materials and components would need to be adapted or replaced. A hydrogen supply infrastructure for road transport would cost in the order of several hundred billion US dollars. If centralised production is adopted, the cost of a worldwide hydrogen pipeline system for the transport sector could range from USD 0.1 trillion to USD 1 trillion. The *incremental* investment cost for hydrogen refuelling stations would be somewhere between USD 0.2 trillion for centralised production and USD 0.7 trillion for decentralised production. A full hydrogen economy with extensive use of hydrogen for both transport and stationary applications would require a global pipeline investment in the order of USD 2.5 trillion, the bulk of which would be for the connection of commercial and residential customers. Assuming the early retirement and partial replacement of the existing natural gas supply system, a significant part of this cost would be *incremental*.

These investment costs can be compared with the global investment of USD 16 trillion that is projected to be required for the overall energy supply system until 2030 (IEA, 2004a). Even considering the uncertainty affecting current estimates, it appears that a transition to hydrogen would add substantially to the total investment cost for the energy system (from a few percent to some tens of percent). In absolute terms, the hydrogen investment as well as the overall energy investment should be compared to the global (undiscounted) world GDP over the period to 2050 (some 5 350 trillion USD) and the total investment (some 23% of GDP, based on annual average). When viewed in this light, the high investment cost for hydrogen infrastructure should not be considered as a deterrent to the transition to hydrogen. Who should bear this investment is, of course, a matter for discussion.

Fuel cells

Fuel cells are the technology of choice to exploit the full benefits of hydrogen in terms of energy-security, emissions and efficiency.

Proton exchange membrane fuel cells (PEMFCs) can be used for both stationary and transport applications. Because of their high sensitivity to carbon monoxide and sulphur pollutants, they need a rather pure hydrogen (*e.g.* produced by electrolysis). If hydrogen is produced from natural gas reforming or from residual industrial gases, purification processes may be needed before use in a PEMFC. At present, PEMFCs seem to be the best candidate for fuel cell vehicles. The current cost of PEMFCs exceeds USD 2 000/kW, but stack cost reductions to USD 100/kW seem to be possible with mass-production and technology learning. However, further reductions to below USD 50/kW are needed to produce competitive FCVs. This will require fundamental advances in materials and higher fuel cell power densities. Research efforts are focusing on high-temperature membranes that are less prone to poisoning and enable on-board reforming. Due to the ongoing developments in PEMFC technology, it would be premature to make choices about the hydrogen infrastructure at this stage, as they will be affected by hydrogen purity requirements. Direct ethanol fuel cells (DEFCs) could also become an interesting option for transport, but they are still at a very early stage of development.

The efficiency of hydrogen fuel cell vehicles (FCVs) is at least two times higher than the efficiency of reference internal combustion engine (ICE) cars. However, FCVs are not yet ready for commercialisation. In addition to cost reductions, they need improvements in their durability (lifetime) and reliability. In addition to the fuel cell stack cost, other components such as the balance of plant, the electric engine and the hydrogen storage system determine the FCV cost. All these items need significant cost reductions to make FCVs competitive. Depending on assumptions for technology development, the stack cost of a PEMFC could decline to USD 35/kW or to USD 75/kW by 2030. Accordingly, the FCV *incremental* cost in comparison with a conventional ICE vehicle could range from USD 2 200 to USD 7 600 per vehicle. Under such assumptions, the *incremental* investment cost to replace 30% of global vehicle fleet by 2050 with fuel cell vehicles (some 700 million fuel cell cars) would range from USD 1 to 2.3 trillion.

While drive systems for fuel cell passenger cars could be competitive at costs of USD 50-100/kW, buses and delivery vans are "niche" markets where fuel cell engines can be competitive (if compared to gasoline/diesel ICEs) at costs of USD 200/kW and USD 135/kW, respectively. Buses could, in principle, be the largest and most promising market. Although current production volumes are very small (10 buses a year), market developments could drive increasing production volumes that result in significant declines in PEMFC stack costs. Following these cost reductions, PEM fuel cells could be introduced in passenger cars as well.

Molten carbonate fuel cells and solid oxide fuel cells (MCFCs and SOFCs) are the best candidates for stationary applications. They are less sensitive to pollutants than PEMFCs. Current MCFCs are fuelled by natural gas, while SOFCs can be fuelled by both hydrocarbons and pure hydrogen. Both MCFCs and SOFCs operate at high temperatures and do not require external reformers. Their electric efficiency is higher than that of PEMFCs. However, they are not suitable for cars, because their high operating temperatures result in long start-up times. Natural gas fuelled MCFCs and SOFCs may co-exist in the coming decades. However, hydrogen-fuelled SOFCs could be favoured if CO_2 emissions reductions are mandatory.

Stationary fuel cells could fill the market between large-scale combined heat and power (CHP) units and small-scale boilers, thus extending the economic feasibility of CHP to the scale of buildings. Decentralised power generation without heat production seems to be less attractive, as the efficiency of fuel cells would be lower than that of other centralised or distributed generation technologies, even if distribution losses are accounted for. While electric efficiencies higher than 60% are still a challenging target for stationary fuel cell systems, CHP applications may achieve much higher overall efficiencies than centralised power plants. Stationary fuel cells can bear higher costs than mobile fuel cells due to their higher load factor and the higher costs of competing options. Their cost is expected to decline by a factor of five to ten and to become competitive once mass-production is introduced. Both the fuel cell stack (50% of the cost) and the balance of plant need to have their costs reduced.

The lifetime of a fuel cell is critical to its overall operating cost. The life span of PEM fuel cells very much depends on the operating conditions, such as low temperature start-up, excessive or insufficient humidification, fuel purity, etc. The average life span for PEMFCs is presently about 2 200 hours (equivalent to a 100 000 km range), but current tests show a significant variability from 1 000 to more than 10 000 hours. The average life span of small-scale residential SOFC systems is currently around 4 500 hours, with some systems lasting more than 20 000 hours. Although, significant advances have been achieved in recent years, increasing the life span and reliability of fuel cells will be imperative to gain consumer acceptance. For mobile applications the target is 3 000-5 000 hours for cars and up to 20 000 hours for buses. In stationary applications the target is 40 000-60 000 hours, which equals 5-8 years of operation.

Direct methanol fuel cells (DMFCs) use methanol as a fuel. They are the best candidates for portable applications, but their low efficiency makes them impractical for possible mobile and stationary uses. In contrast, PEMFCs are not practical for portable devices, because of hydrogen storage problems. MCFCs and SOFCs are not practical either, because of their high operating temperatures. In terms of commercial maturity, portable DMFCs appear close to market introduction. They are likely to be followed by stationary MCFCs and SOFCs systems for decentralised use. More time is needed for the commercialisation of mobile PEMFCs, although they are urgently needed to meet environmental and energy-security objectives.

Competing technologies

Hydrogen and fuel cell technologies compete with many alternative fuels and technology options that can be used to meet energy-security and environment goals. The analysis in this study suggests that an assessment of the potential of hydrogen and fuel cells that does not take into account competing options would result in misleading conclusions and in an overly optimistic assessment of hydrogen's potential. Development risks and uncertainties must be taken into account in setting energy policies and strategies, and picking "winners" at this stage is premature.

In the transport sector, competing options include biofuels, Fischer-Tropsch (FT) synfuels from coal and gas, compressed natural gas, hybrid ICE and plug-in hybrid vehicles. Biofuels are an affordable alternative fuel in transport sector in the short-term, but biomass availability limits biofuel use. Current hybrid vehicles, as well as hydrogen-hybrid vehicles, could also represent a viable alternative to hydrogen FCVs. While the deployment of hydrogen FCVs faces a "chicken-or-egg" problem (no demand without infrastructure investment and no investment in expensive infrastructure without demand), other technologies and fuel options do not face similar introduction barriers. Hydrogen hybrid vehicles face a tougher on-board storage issue (because of their lower efficiency than FCVs) and a similar chicken-or-egg problem. However, they do not require challenging cost reductions like the FCVs.

For both stationary and mobile applications, competing options are energy efficiency and large-scale electrification based on coal with CO_2 capture and storage, nuclear, or even renewables. Large-scale electrification in conjunction with plug-in hybrid vehicles and Li-ion batteries could also lead to re-consideration of the role of electricity in transport. Hydrogen and fuel cells also face significant competition in the stationary applications market, either for distributed electricity generation or cogeneration. Large, highly-efficient coal and gas-fired power plants with CO_2 capture and storage (CCS), emerging renewable electricity supply technologies, and new nuclear power technologies are strong competitors that fuel cells and all distributed technologies must beat. At the same time, new technologies such as micro-turbines and Stirling engines are being introduced in combined heat and power applications. Enhanced building insulation and industrial energy efficiency may also limit future heat demand. This reduced heat demand limits the potential for stationary fuel cells in CHP applications, but at the same time an increased power-to-heat ratio makes fuel cells more attractive compared to other CHP technologies.

Market prospects for hydrogen and fuel cells

New technologies may quickly conquer the market if they offer immediate, individual benefits such as lower costs, superior performance, or even costly but attractive new services. If this is not the case, if the new technologies offer "only" collective economic or social benefits in the mid to long term, then they will need government policies and technology learning driven by public/private investment to become economically competitive and enter the market.

At present, hydrogen and fuel cells appear as a rather costly option to mitigate CO_2 emissions and enhance energy-security. Even the current prospects for cost reductions are unlikely to result in a significant economic advantage over existing technologies. In business-as-usual scenarios, with no substantial new policies for environmental protection and energy diversification, hydrogen as well as other new technologies do not have any significant roles in the future energy mix. Also, policies solely aimed at enhancing energy-security would not necessarily result in a switch to hydrogen. In a CO_2-unconstrained world, other technologies and fuels (*e.g.* coal) would be more cost-effective for increasing energy diversification.

Hydrogen is likely to conquer a significant market share only if effective policies for CO_2 mitigation and energy-security are in place and combined with considerable reductions of hydrogen and fuel cell cost. Policies for CO_2 mitigation and energy-security act in concert in promoting a number of new energy sources and technologies such as renewable and nuclear energy, coal use with CO_2 capture and storage, and hydrogen as well. For the sake of this study, these policies have been collectively represented by an economic incentive to reduce CO_2 emissions. The incentive – expressed in USD per tonne of CO_2 avoided – represents a variety of regulatory measures, subsidies and other policy instruments that have the effect of promoting hydrogen and fuel cells, as well as other technologies with the potential for emission mitigation and energy diversification. All these policy instruments have the net effect of giving new technologies a value in terms of emissions avoided, and help improve the diversity of the energy system. For example, under reasonable assumptions on technology advances, an incentive that increases gradually up to USD 50/t of CO_2 would stabilise emissions over the period 2000-2050, and halve the business-as-usual level of emissions in 2050. The resulting energy mix would also be significantly more diverse. While a technology-neutral approach that provides a uniform incentive to curb emissions may be difficult to achieve in practice, for the purposes of this study the CO_2 incentive is the best instrument to identify cost-effective technology options. The actual specification of single policy measures would not provide any further insights into the cost-effectiveness of these options on a global or regional scale.

The adoption of the CO_2 incentive paves the way to tough competition among a number of new technologies with the potential to reduce emissions. None of them seems able to play a dominant role in the future energy market (there is no energy technology "silver bullet"), in comparison to the role played by oil in transport. However, their collective use stabilises emissions and improves diversity and supply-security in the energy system. In all scenarios with CO_2 policies, the trade in oil is reduced by 30-50% compared with the base scenario without CO_2 policies. This is a significant improvement in the security of supply, but it cannot be attributed to hydrogen and fuel cells alone. However, hydrogen and fuel cells are part of this broader technology portfolio.

In the most favourable scenario (*i.e.* ESTEC D, Chapter 7), with the CO_2 incentive and quickly declining hydrogen and fuel cell costs, hydrogen emerges as a player in the future transport sector beyond 2030. Some 12.5 EJ (0.3 Gtoe) of hydrogen would be used in 2050, mostly in the transport sector. While in absolute terms this appears to be a limited amount of energy in comparison with the total primary energy supply of around 785 EJ (18.8 Gtoe), its impact on transportation is very significant. The efficiency of PEM fuel cell vehicles is such that some 30% of the global fleet of passenger cars (some 700 million cars) would be fuelled by this relatively small amount of hydrogen in 2050. Fuel cell vehicles (cars, delivery vans, etc.) would start gaining market share between 2015 and 2025. If hydrogen for energy use is added to hydrogen for other applications (refinery and chemicals) more than 22 EJ of hydrogen would be used in 2050. This amount represents a more than a four-fold increase with respect to the current level of hydrogen production.

However, hydrogen plays a significant role only under favourable assumptions. Under less optimistic assumptions for technology development and policy measures, hydrogen and fuel cells are unlikely to reach the critical mass that is needed for their successful market uptake. Market introduction barriers and competing fuels and technology options such as biofuels and FT synfuels would play a more important role.

If the most favourable scenario is compared to a similar scenario where hydrogen and fuel cells are not part of the technology portfolio, the net benefit of hydrogen and fuel cells is found to be a 5% reduction in CO_2 emissions (1.4 Gt of CO_2) and a 2% reduction in oil use in 2050. This may appear to be a limited benefit. However, if vigorous CO_2 policies are in place, the resulting fuel/technology mix is optimised for emissions mitigation. In these conditions, a number of new technologies such as hydrogen, biofuels, CNG and FT synfuels from coal and gas with CCS would be playing a role in a competitive energy market. In such a diversified and optimised world, the role played by a single emerging technology is necessarily limited. Neither hydrogen nor other emerging technologies seem to be crucial to mitigate emissions, but their collective use results in the stabilisation of emissions. However, the lack of hydrogen would result in significant changes in the structure of the transportation system. The 30% of passenger cars and light and medium trucks fuelled by hydrogen fuel cells in 2050 would be replaced by ethanol vehicles (about 10%) and by advanced gasoline ICEVs, hybrids and natural gas fuelled vehicles (the remaining 20%). Along with the emissions coming from additional FT synfuel upstream processes, the increased use of gasoline and natural gas to fuel vehicles would account for the total emission increase of 1.4 Gt of CO_2 in 2050.

The diversification of the energy system is such that the lack of hydrogen in the energy mix would not imply dramatic changes for energy-security either. The net impact would only be a 2% increase in total conventional and unconventional oil use by 2050. However, oil imports from Middle East by 2050 would increase by 14% due to the earlier depletion of non Middle-East oil supply sources, and a much more rapid expansion of other oil substitutes would be needed in the transportation sector.

In all scenarios, stationary fuel cell capacity ranges from 200 GW to 300 GW by 2050, equivalent to 2-3% of total installed capacity. This result suggests that stationary fuel cells, namely SOFCs and MCFCs, represent a robust technology option that is not significantly affected by policy strategies and other variables. Most such fuel cells would be fired by natural gas and up to 22% of them would use oil products. As a consequence, stationary fuel cells would not result in nearly zero-emissions. Hydrogen PEM fuel cells for stationary applications do not show up in any scenario. This result can be explained by the high cost of a dedicated hydrogen supply system and by the flexibility of the SOFC and MCFC systems, which do not need a fuel reformer, are less sensitive to poisoning than PEM fuel cells and have superior conversion efficiencies. However, stationary hydrogen fuel cells could benefit from the development of a hydrogen distribution system for transport. Such a synergy has not been considered in the analysis, but could lead to hydrogen fuel cells playing a more important role than suggested by the scenarios here. Stationary fuel cells would concentrate in the residential, commercial and industrial sectors and fill the market between large-scale CHP units and small-scale boilers. They would thus extend the economic feasibility of CHP to the scale of buildings. Fuel cells for centralised power production play a role in only one scenario, in combination with coal-fired IGCC plants (25 GW IGCC-SOFC plants installed worldwide by 2050).

In cost-optimal scenarios, hydrogen production in the early market uptake phase is primarily based on decentralised natural gas reforming and electrolysis. Centralised production from coal and natural gas with CO_2 capture and storage would then play a major role in the long-term. Production from nuclear and renewable energy does not play a significant role. However, the cost of hydrogen production from nuclear heat or from biomass might be only slightly higher than that from fossil fuels. So nuclear and renewable hydrogen could enter the production mix, especially if production cost is not the only criterion for the selection of the production technology, or technologies for CO_2 capture and storage do not become available or competitive.

Decentralised production in the early market introduction phase increases the cost of hydrogen, but not the cost of the overall system. The limited hydrogen demand in the initial market phase does not justify the construction of a large distribution infrastructure.

If ambitious climate and energy-security policies are adopted world wide, the regional potential for hydrogen and fuel cells seems to be high in the OECD, China and India. In all regions, transport applications (hydrogen fuel cell vehicles) dominate the hydrogen market. The share of hydrogen FCVs varies widely across regions. In the most optimistic scenario, the region with the highest hydrogen FCV share in the vehicle stock by 2050 is actually China (60%) followed by India, which has up to 42% hydrogen FCV share in 2050. A leap-frogging effect may occur in these countries as they have limited existing infrastructure for transport fuels already in place. Their large indigenous coal reserves, potentially available for hydrogen production, may also facilitate a transition to hydrogen. This result however is highly scenario-dependent. The share in OECD countries is somewhat more stable across scenarios. In most favourable scenario, it ranges from 10% in Australia to 22% in Japan, 35% in Canada, 36-48% in Europe and 42% in the United States. Hydrogen use in other regions is negligible.

Hydrogen use would start around 2015-2020 in Europe and North America, and around 2025 in the other regions. This relatively narrow window in which uptake begins in various regions suggests that favourable conditions for hydrogen introduction exist in different economies and geo-political areas. Hydrogen is an option of interest for most OECD countries and large, rapidly growing developing countries with limited indigenous oil resources. Differences in hydrogen penetration across regions may be explained by different economic conditions, discount rates, availability of infrastructure, citizen attitude to investment in capital-intensive technologies, energy and fuel taxes, and mobility needs. In absolute terms, hydrogen use in the OECD Pacific appears to be significantly lower than in the other OECD regions. In terms of per capita use, the difference is much smaller. However, the difference can be explained by the lower energy intensity in key countries of the OECD Pacific area (notably Japan) and the lower annual car-mileage, which does not favour investment in capital-intensive technologies such as FCVs. Current per capita oil product use in North American is a factor of 2.2 to 2.6 times higher than in the OECD Europe and OECD Pacific regions.

Uncertainties, challenges and opportunities

Hydrogen and fuel cells can play a role in the energy sector under a range of future conditions that are subject to significant uncertainties. There are three key areas of uncertainty: economic developments, energy policies and market conditions; the future rate of development of hydrogen technologies; and competing options to meet policy targets.

A limited number of factors have a positive effect on the future use of hydrogen, while most of them have a negative effect. The sensitivity analysis indicates a maximum variation of ±80% in hydrogen if individual drivers are varied. Factors with a major impact are: climate change and energy-security policies; future FCV costs and performance; the severity of the chicken-or-egg transition problems; the timely development of centralised hydrogen production and distribution infrastructure; and consumers' criteria for buying cars. Changes in the future oil supply (quantities and prices) are also of primary importance. Competing technologies also play an important role, but their effect is less sensitive to their technical characteristics. Also, specific measures aimed at enhancing the security of supply do not have a major impact if substantial CO_2 policies (*i.e.* CO_2 reduction incentives) are in place.

However, major uncertainties concern whether and how these factors will materialise, rather than their individual impact on the potential of hydrogen and fuel cells. For example, international agreements on concerted measures to curb emissions and enhance security are difficult to achieve and very time-consuming. Similarly, the future of coal-based hydrogen and electricity cogeneration may be affected by the feasibility, cost and social acceptance of the CO_2 capture and storage technology. Strong developments in nuclear and renewable energy may favour hydrogen and fuel cells. However, they could also result in strong competition for hydrogen by making large-scale, cheap and CO_2-free electricity and biofuels available as alternative options to mitigate emissions and enhance energy-security.

In the transport sector, uncertainties not only concern the choice of PEMFC materials, the on-board storage system, and the choice between hybrid ICEVs and FCVs, but also who will bear the investment in hydrogen production, distribution and refuelling infrastructure. At present, it is unclear what the incentive would be for oil companies and electrical utilities to invest in hydrogen infrastructure, unless clear government policy goals are established.

How fast the production of hydrogen can expand is also an important issue for the transition to hydrogen and possible promotion policies. Current cumulative FCV production stands at about 600 vehicles, compared to *annual* car production of 50 million vehicles a year. At the moment, no car producer has plans to mass-produce hydrogen fuelled vehicles. Producers will probably initially offer a single model in a single country to explore market acceptance, and then will gradually expand to other regions. Experience from other technologies and industrial sectors may be of interest. The introduction of hybrid vehicles took a decade to achieve a 0.5% share of the market. The semi-conductor industry (which faces no competition) has grown at a rate of 15% per annum over the period 1960-2000. At such a high growth rate, the fuel cell car market would increase from 0.5% to 30% in 30 years.

How fast the production volume will grow is important for technology learning and the rate of cost reduction, which in turn affects the setting of promotion policies. Should hydrogen introduction be supported by public incentives in the early market phases, the level of the required financial support will depend strongly on how rapidly costs can decline.

The analysis of uncertainties suggests that solving technical issues alone will not be enough to bring hydrogen and fuel cells to the market. In addition, the timely achievement of the most ambitious targets for technology development (performance and cost reduction) appears to be an essential condition for their success. Delays in technical progress could result in other technologies that are closer to commercial maturity "locking-in" their market position at the expense of hydrogen and fuel cells.

Current public spending on hydrogen and fuel cells RD&D (USD 1 billion a year) is substantial when compared to the total annual public budget for energy RD&D of around USD 8 billion. Nevertheless, present efforts are small in comparison with the investment that will be needed to support the introduction of hydrogen technologies in the energy market. This would imply a landslide change in government energy policy priorities, with a dominant emphasis on technology innovation. In an ideal world, governments should first establish credible and durable energy-security and environment policies and targets, without which no reason exists to switch to hydrogen. They should then foster the establishment of international standards for hydrogen and fuel cells in close consultation with industry, promote infrastructure investment and provide incentives for consumers to adopt new technologies. Government procurement programmes (*e.g.* for car fleets) to promote niche markets and technology learning should also be an important part of government's policy strategies. The past trends in energy RD&D budget run contrary to the need for increased efforts. Government energy RD&D budgets have been falling in recent decades, with total energy RD&D expenditure in 2002 of just under USD 8 billion, just 50% of the 1980 value in real terms.

In the transportation sector, the current private RD&D investment exceeds public investment. However, industrial strategies differ considerably. DaimlerChrysler and Ford rely on Ballard fuel cells while General Motors, Honda and Toyota are developing their own fuel cells. GM is developing the skateboard chassis FCV concept. DaimlerChrysler is focusing on fuel cell vehicles and bus test fleets. Nissan is already leasing FCVs to private customers for demonstration purposes and Honda is aiming to do so by the end of 2005. Ford and Mazda Motor Co are simultaneously working on hydrogen ICE vehicles. BMW is working on hydrogen ICEs with fuel cells used for the auxiliary power units. Toyota is following a phased approach, first commercialising its hybrid vehicles and subsequently aiming to integrate fuel cells into the hybrid concept. A number of other car companies focus not only on hydrogen, but also on other solutions such as biofuels (*e.g.* Volkswagen and Peugeot-Citroën). Several new players are trying to enter the car market based on the revolutionary fuel cell engine technology. The initial target for market introduction in 2004 has subsequently been moved to 2010. Some major car makers are now talking about introduction after 2012 and other companies envisage commercialisation after 2020. This suggests that achieving the target of replacing conventional vehicles and fuels to curb emission and improve energy-security is a more challenging goal than originally expected, and that different visions exist on how to get there.

The discussion of hydrogen and fuel cell technologies shows a wide range of possible options, from market-ready solutions to theoretical concepts. While selecting winners is premature, identifying technologies that may become important in the short-term, as well as those that are further away from market introduction, is an important component of the process for setting RD&D priorities and investment.

There are *low-risk/low-reward* options such as natural gas reforming and water electrolysis, coal gasification, high-pressure gaseous storage, improved fuel cell balance of plant costs and manufacturing technologies, hydrogen burners for gas turbines, and hydrogen ICEs. What these technologies may offer and their possible development is rather well documented. There are also technologies with larger margins for improvement, such as new materials for PEM membranes and catalysts. There are also technologies that will potentially have a broader impact, not just on hydrogen and fuel cells (*e.g.* CO_2 capture and storage). A different category is the *high-risk/high-reward* technology options, such as photo-electrolysis, biological production of hydrogen, water splitting using nuclear heat and the S-I cycle, on-board solid storage options, and new fuel cell concepts. If successful, some of these options may represent major breakthroughs in energy technology with tremendous impacts on future applications of hydrogen and fuel cells, and on the overall energy system. At present, most of these options are in a very early stage of development and the data available on their potential development and costs do not allow a quantitative analysis to be conducted. Therefore, they have not been included in this study. However, a balanced RD&D investment strategy based on costs/benefit analyses should take into account these technology options, despite their very early stage of development.

Taking a slightly broader view on the potential of RD&D investment in hydrogen and fuel cells, it should be noted that the relevant RD&D work does not need large single investments such as some centralised energy technologies (*e.g.* nuclear). As a consequence, RD&D activities are currently carried out in a number of small and large, public/private laboratories and research organisations. In principle, with such a huge number of opportunities and economic attractiveness, some technology solutions could already be in the infancy stage of their development, or even available in industrial labs, pending patent applications or in the expectation of a future market start-up. In addition, many aspects of hydrogen and fuel cell RD&D deal with developments in solid state physics and materials science. These booming disciplines promise tremendous advances with potentially broader impact on technology, including unexpected and pleasant breakthroughs in hydrogen and fuel cells.

Chapter 1. INTRODUCTION

The role of hydrogen and fuel cells

Security of energy supply, high oil prices and growing emissions of greenhouse gases continue to pose unresolved challenges for the global economy and the climate of the planet. Oil and, to a lesser extent, natural gas supplies will come increasingly from the OPEC countries. To meet projected growth in oil demand, OPEC will have to increase its oil production from 28.2 million barrels per day in 2002 to 64.8 million barrels per day in 2030 (IEA, 2004a), resulting in OPECs share of oil supply exceeding half of global demand in 2030. Over the same period OECD oil production will almost halve. The increased dependence on imported oil will clearly reduce the supply security and create continued upward pressure on oil prices.

While oil prices and supply security represent immediate or short-term issues for the global economy, the impact of climate change is a possible mid- to long-term challenge with unprecedented implications for the environment and the economy. Emissions of greenhouse gases have been constantly growing over the past years, despite mitigation efforts, and are projected to continuously increase over the next decades if current trends in energy policy, supply and use continue.

Consensus exists in the international community that urgent actions are needed to face short-term energy security problems and pave the way to the mitigation of future climate change, and that energy technology and policy are part of the solution. Increased energy efficiency and conservation, and the development of new technologies will be central to reducing our dependence on hydrocarbons and the resulting emissions. There is no energy technology "silver bullet", however. No one technology promises to hold the solution to all problems in itself, and all options will need to be carefully explored. Considerable technology advances and even breakthroughs are needed in a number of domains to achieve cost-effective renewables such as photovoltaic and biomass, acceptable nuclear waste management, low-cost CO_2 capture and storage for fossil fuels, and – not least – efficient energy end-uses, particularly in transport and residential uses.

Hydrogen and fuel cell technologies promise considerable benefits in terms of reducing greenhouse gas emissions and potentially improving the security of energy supply. However, before they can enter the market in any meaningful way, they will require significant technological breakthroughs and lower costs. Potential synergies exist among different research and development (R&D) domains. For example, cost–effective techniques for CO_2 capture and storage are critical to the production of nearly CO_2-free hydrogen from fossil fuels. This would allow coal to become a large source of cheap and clean hydrogen. Similarly, in the long-term, cheap renewable energy could open the way to low-cost hydrogen production. In recognition of these multiple targets, and the complexity of any potential solution, no single energy source or technology should be ruled out at this stage. If the challenges to the global economy and climate are to be met, public budgets for energy technology R&D should be increased and the most promising areas of research given a boost.

Hydrogen is a clean gaseous energy carrier. Unlike hydrocarbons, it does not occur naturally in any significant quantities. Hydrogen can be produced from a wide range of energy sources such as coal, natural gas, nuclear and renewable energy. It could be used in many stationary and mobile energy applications. Recent technology advances have increased attention on the use of hydrogen and fuel cells as a substitute, or complement, to oil-based fuels and internal combustion engines in transport. Hydrogen can be used in highly efficient fuel-cell vehicles (FCVs). Critically, depending on the characteristics and overall efficiency of the well-to-wheel energy chain, a transportation system based on hydrogen FCVs could result in dramatic reductions in oil demand and hence emissions. Reducing oil's dominance in the transport sector and increasing the efficiency of transport vehicles could also significantly improve the security of energy supply. However, this benefit will depend on the primary energy sources used for hydrogen production. The largest benefits would probably accrue if hydrogen was produced from coal, renewable or nuclear energy sources.

In principle, a hydrogen-based energy system doesn't result in any carbon dioxide (CO_2) emissions at the point of use. If hydrogen is used in fuel cells, or burned with pure oxygen in conventional combustion processes, it produces only water (H_2O) as a combustion product. If burned with air, depending on the combustion conditions, hydrogen produces nitrogen oxides. Using hydrogen in FCVs could in principle significantly reduce the emissions of CO_2 and those of local air pollutants in the transport sector. However, the emissions of a hydrogen-based energy system depend on the primary energy source and the process used to produce hydrogen. If produced from fossil fuels via natural gas steam reforming or coal gasification, hydrogen is a nearly CO_2–free energy carrier only if the carbon dioxide emerging from these processes is captured and stored. If produced by water electrolysis, the emissions of the hydrogen production depend on the upstream process to produce electricity.

Given the limited availability of electricity generation from CO_2-free sources in most regions and that the feasibility of CO_2 capture and storage technologies is currently being tested in demonstration projects, the potential for producing hydrogen without the emission of CO_2 is currently limited. However, new technologies for producing hydrogen directly from renewable and nuclear primary energy sources are being actively researched and developed.

While strong synergies exist between hydrogen and fuel cells, they are not necessarily linked together. Hydrogen can fuel conventional combustion engines and turbines, while some fuel cells can use fuels other than hydrogen. In this report, special attention is focused on the potential of fuel cells running on hydrogen as they offer special efficiency advantages in the transport sector. They could also be an attractive option in the residential and industrial sectors, for distributed heat and power generation.

The infrastructure for hydrogen production, transportation and distribution is also a significant issue. Storing, moving and distributing hydrogen are energy intensive and expensive processes because of the low volumetric energy density of hydrogen compared to natural gas. To compensate for the low energy density, hydrogen must be compressed to a high pressure, liquefied at very low temperature, or absorbed in solid materials. While compression and liquefaction are mature, albeit energy-intensive and costly processes, hydrogen storage in solid materials is still a matter of active R&D. Hydrogen transportation via pipeline is also much more expensive in terms of energy and investment costs in comparison to natural gas.

The large-scale production of hydrogen is an established technology. Hydrogen is currently widely used in refinery and chemical processes. There are no established hydrogen statistics, but the total amount of hydrogen used is thought to be around 5 EJ per year, or more than 1% of global primary energy demand. In addition, significant quantities of industrial gases are mixed with some hydrogen and then used in energy recovery processes. This includes coke oven gas, refinery gas and residual gas from steam crackers. However, if hydrogen is to be used for energy applications it will have to overcome a number of hurdles: production costs will have to fall in order to compete with other fuels; cost-effective technologies for transportation, storage, and distribution have to be developed; and cheap and efficient fuel cells should be made available. Research and development is essential to make these technologies economically viable, while an analysis of the competing technology options is essential to assessing the real potential of hydrogen as an energy carrier.

Investment and targets in RD&D

In recent years fuel cells and hydrogen have received increasing attention and R&D funds. The expectation is that a few decades from now fuel cells and CO_2-free hydrogen from fossil, renewable and nuclear primary energy sources could be entering the market and gaining a significant share in the transport sector, as well as in the industrial, residential, and the power generation sectors. For this to occur, intense public and private research, development and demonstration (RD&D) efforts and corresponding technology breakthroughs are needed to make these technologies commercially mature. Driven by recent technical advances and the need to mitigate greenhouse gas emissions, OECD governments have intensified their RD&D efforts on hydrogen and fuel cells.

The IEA has recently published a review of the RD&D programmes for hydrogen and fuel cells in IEA countries (IEA, 2004b). A number of new initiatives are increasing the global public RD&D investment for hydrogen and fuel cells. At the end of 2004 the public spending amounted to some USD 1 billion a year and represented some 12% of all public energy RD&D[1]. The initiatives are equally distributed in the three OECD areas, Asia-Pacific, Europe and North America. More than half of these funds are being spent on fuel cells, while the rest is going towards technologies to produce, store, transport and use hydrogen (including technologies other than fuel cells, such as internal combustion engines and turbines fuelled by hydrogen).

Government-funded research is indispensable as a catalyst for the development process. However, public research is not the dominant part of the global effort on hydrogen and fuel cells. Private sector investment by major oil and gas companies, vehicle producers, electrical utilities, power plant constructors, and a number of players in the current hydrogen and fuel cell market is thought to be considerably larger.

This global effort is expected to continue in the coming years, as many countries have planned multi-year investments. The United States has a USD 1.7 billion programme over five years, while the 6th Framework Programme of the European Commission over the period 2002-2006 plans up to EUR 2 billion for renewable energy RD&D, including hydrogen and fuel cells. Japan has pledged more than JPY 30 billion a year, and other multi-year programmes are in place in other major OECD and developing countries. Government RD&D efforts and long-term commitments are complemented by international co-operation initiatives. Most of the 26 IEA countries are involved in the IEA Hydrogen Co-ordination Group and the IEA Implementing Agreements. OECD and non-OECD countries such as Brazil, China, India, Iceland and Russia also co-operate within the context of the International Partnership for Hydrogen Economy (IPHE). The European countries collaborate within the European Technology Platform for Hydrogen and Fuel Cells, a cluster of public/private RD&D initiatives within the European Commission's Framework Programme.

National activities range from large integrated government-funded programmes to smaller strategies with multiple public and private initiatives. Many countries that are closely involved in hydrogen and fuel cell development have set specific RD&D and market deployment targets. For example:

- Canada's programme is delineated in 3 phases. Phase 1 (R&D, Demonstration and early Deployment: 5 years) aims to support industry's pre-commercial efforts, reduce costs, begin infrastructure development, develop codes and standards, and educate staff and users. Phase 2 (Broader Deployment:

1. This global public spending does not emerge from current statistics for energy RD&D, because efforts to produce hydrogen from fossil, nuclear and renewable sources are accounted for in the RD&D budgets for these energy sources . Similarly, fuel cell RD&D is included in the relevant RD&D budget for the end-use technology.

5-10 years) aims to foster emerging technologies, expanding infrastructure and continuing RD&D. Phase 3 (Market Expansion: 10-20 years) aims for mass production and infrastructure development on a national level.

- Japan's commercialisation programme also includes three phases. Phase 1 (2002-2005) will focus on the demonstration of automotive and stationary fuel cells, development of codes and standards, and soft infrastructure. Phase 2 (2005-2010) will focus on the *Introduction Stage*, with the development of a supply system and the accelerated introduction of fuel cell vehicles. Phase 3 (2011-2020 and beyond) will focus on the *Diffusion Stage*, with the private sector promoting "self-sustaining growth" in the fuel cell market and fuel supply system.

The ambitious commercialisation goals these programmes set provides an idea of the current expectations about hydrogen and fuel cell development and the urgent need for RD&D progress if these goals are to be met. Significant differences also emerge in regional policies and targets.

In Japan, the commercialisation target by the end of the *Introduction Stage* (2010) is 50 000 fuel cell vehicles and 2.2 GW of stationary fuel cells. By the end of the *Diffusion Stage* (2020) the target is 5 000 000 FCVs, 4 000 hydrogen stations and 10 GW of stationary fuel cells. Japanese expectations also include 15 million FCVs running in the country in 2030 and 12.5 GW of stationary fuel cells. These targets require a considerable improvement in technology performance and cost reductions. The goal is to make available by 2020 FCVs with a cruising range of 800 km (7 kg H_2 storage) and a system cost of USD 35/kW. The target production cost for hydrogen (excluding taxes) is USD 34/GJ by 2020, equivalent to the current gasoline price including taxes.

A demonstration project with about 60 FCVs and 10 hydrogen stations is ongoing in the Tokyo-Kanagawa area (METI, 2005a, 2005b). Japan is also aiming to develop a two-wagon fuel cell train with a capacity of 140 passengers per wagon. With a power of 800 kW and a fuel cell durability of 40 000 hours, the train would operate at a maximum speed of 130 km/h. The challenge is to reduce the cost of such fuel cell drive system to the same level as that of diesel train engines, *i.e.* USD 90/kW. The focus for stationary fuel cells is on cogeneration systems for household use. Stationary, natural gas polymer electrolyte membrane (PEM) fuel cell systems have been installed at 33 locations in Japan. The best power efficiency was more than 32%. These systems also achieve 40-50% heat recovery efficiency. The target price of such systems would be less than USD 4 500/kW, which implies a significant cost reduction from current manual manufacturing. Preliminary assessments indicate a potential cost reduction of a factor of 10 based on mass production. A large-scale demonstration programme of more than 2 000 units is currently under way and the development of a mass production by 2008 is being considered.

The Republic of Korea has also announced plans for fuel cell commercialisation. Korea aims to have 10 000 FCVs, 500 fuel cell buses, 50 hydrogen refuelling stations, 300 fuel cell units for distributed power generation (250-1000 kW) and 2 000 units for residential use (10-50 kW) by 2012.

The United States Department of Energy (US-DOE) envisions a phased transition to hydrogen, with a commercialisation decision in 2015. In the US programme (US-DOE, 2005), the success is broadly defined as validation by 2015 of technologies for:

- Hydrogen production at competitive costs with gasoline and no adverse environmental impact.
- Hydrogen storage for more than 300-mile vehicle range with affordable cost.
- Fuel cell vehicle engines at less than USD 50/kW and stationary power systems at USD 400-700/kW, with appropriate durability.

While the full extent of hydrogen benefits will not be achieved for decades, meeting these requirements in 2015 would enable industry to move towards the commercialisation of hydrogen fuel cell vehicles and the development of the needed infrastructure, and would begin to yield benefits as early as 2025.

Specific targets have been identified in the US-DOE programme (Table 1.1) to measure the RD&D progress. These targets are continuously revised in accordance with the lessons being learnt from ongoing RD&D activities. For example, in 2004, the US-DOE decided to abandon its programme of on-board reforming. Similarly, the targets for FCVs start-up time (less than 1 minute) and start-up energy (less than 2 MJ for a 50 kW system) could not be met and were abandoned (US-DOE, 2004).

Table 1.1

Targets in the US RD&D programme

Hydrogen production	
2010	• Distributed production from natural gas at USD 1.50/kg (USD 12.5/GJ) delivered at pump, excl. tax, no CO_2 capture and storage.
	• Grid-connected distributed electrolysis at USD 23.8/GJ delivered.
2015	• Distributed production from biomass-derived liquids at USD 20.8/GJ delivered, excl. taxed.
	• Centralised production from renewable sources at USD 22.9 /GJ delivered.
	• Production from biomass at USD 13.3/GJ at the plant gate and USD 21.7/GJ delivered.
	• Develop and verify the long-term economic feasibility of hydrogen production from photo-electro-chemical and biological processes.
	• Develop solar-driven, high-temperature thermo-chemical production at USD 25/GJ and at USD 33.3/GJ delivered.
Hydrogen delivery	
2010	• Delivery from centralised production facilities to refuelling stations at less than USD 7.5/GJ and compression, storage and dispensing at refuelling stations/stationary facilities at less than USD 6.7/GJ.
2015	• Delivery from producer to end-users (mobile or stationary use) at less than USD 8.3/GJ.
Hydrogen storage	
2010	• On-board hydrogen storage systems achieving 2 kWh/kg (6 wt %), 1.5 kWh/L and USD 4/kWh (USD 1110/GJ).
2015	• On-board hydrogen storage systems achieving 3 kWh/kg (9 wt %), 2.7 kWh/L and USD 2/kWh (USD 555/GJ).
Fuel cells	
2010	• Durable, direct hydrogen fuel cell system for transportation (60% peak-efficient) at USD 45/kW.
	• PEM fuel cell for distributed generation systems (natural-gas or LPG fuelled, 40% electrical efficiency and 40 000-hours durability) at USD 400-750/kW.
2015	• Durable, direct hydrogen fuel cell system for transportation (60% peak-efficient) at USD 30/kW.
Technology validation	
2008	• Wind turbine-powered electrolysers (65% efficiency, incl. 5 000 psi compression) at USD 400/kWe (for 1,000 units).
2009	• Hydrogen vehicles with a range exceeding 250 miles and 2 000-hour fuel cell durability.
	• Hydrogen infrastructure with production cost of less than USD 25/GJ excl. tax.
2011	• Integrated biomass, wind and geothermal electrolyser hydrogen production systems at USD 21.5/GJ at the plant gate excl. tax.
2015	• Hydrogen vehicles with 300+ km range and 5 000-hour fuel cell durability.
	• Hydrogen production cost of USD 12.5/GJ excl. tax.

Source: US-DOE, 2005.

The European Union development plans aim for hydrogen to represent 2% of the total transportation fuel by 2015 and 5% by 2020. Some 2 000 FCVs are expected to be running throughout Europe by 2012-2015, with commercialisation in the period 2015-2020 (EC, 2004). The goal also is to install 5 MW of stationary fuel cells by 2005-2006, 30 MW by 2006-2008 and 200 MW by 2009-2010. This is in addition to 200 MW micro-CHP residential fuel cell systems (<5 kW) and 400 MW of industrial CHP systems by 2015-2020. The industrial systems should be commercialised from 2012-2015 and the micro-CHP systems from 2015-2020.

The European Commission is also implementing ambitious voluntary agreements with car manufacturers to reduce CO_2 emissions in the transport sector. These agreements could also help accelerate the development and commercialisation of hydrogen FCVs. To meet the target of the upcoming EU legislation, European, Japanese and Korean car manufacturers have committed to reduce CO_2 emissions from new passenger cars to an average of 140 grams per kilometre (g/km) in 2008 (2009 for Asian cars). The deal was sealed by ACEA, the European automotive industry association, in a voluntary agreement signed with the Commission in 1999. The ultimate objective is to reduce emissions to 120 g/km in 2012. Hydrogen FCVs could play a significant role in meeting these targets, as they have a considerably higher efficiency than internal combustion engines (ICEs) and zero tailpipe emissions.

In 2003 European car manufacturers sold the lowest emission cars, at just 163 grams of CO_2 emitted on average per km. In comparison, Japanese cars sold in Europe emitted an average of 172 g/km and Korean cars 179 g/km. On average, CO_2 emissions from new passenger cars sold in the EU-15 decreased by 11.8% between 1995 and 2003. This represents an important improvement. However, the new targets set for 2008-2009 seem to be extremely challenging.

The interest in hydrogen is not limited to the OECD countries. Brazil, China, India and Russia are also committed to hydrogen and fuel cells development. China is aiming to introduce hydrogen fuel cell buses as a demonstration project at the Beijing Olympic Games in 2008, and to initiate a mass production of fuel cell vehicles from 2010 onward (Ouyang, 2004).

The importance of technology learning

The cost of new technologies generally decreases significantly when moving from the demonstration phase to the market introduction phase. However, because of the low level of initial demand and hence production, this cost is in general still high in comparison with the costs of mature technologies. A further gradual but significant cost reduction usually occurs as the market expands and demand grows. This process, known as "Technology Learning", is a result of various mechanisms. Initially, RD&D-driven technology improvements play a key role, while the shift from labour-intensive to capital-intensive (automated) production results in further cost reductions. Finally, economies of scale due to mass production (learning by doing) continue to lower costs. This pattern has been observed for many technologies (IEA, 2000) and will be of vital importance for hydrogen and fuel cells, as their costs are currently not competitive with existing technologies. For example, the cost of current demonstration fuel cell vehicles (FCV) is estimated to be in the order of a few thousand USD per kW for a 75 kW system (complete drive system). Car manufacturers are fairly confident that technology learning should be able to bring the cost down quickly, by at least one order of magnitude. However, not even a fuel cell system cost of a few hundred USD per kW, including hydrogen storage, would be competitive with current internal combustion engine vehicles (USD 30-50/kW).

While cost reductions will occur, there is considerable debate as to the potential magnitude of the cost reduction and the pace at which this would be achieved. Previous IEA studies have shown that learning rates vary considerably across different technologies and that they can vary over time for individual technologies. A detailed assessment of cost reduction mechanisms and the consequences of uncertainties for investment costs is needed to arrive at the most robust estimates of the potential cost reductions for hydrogen and fuel cells.

Background and scope of this study

The previous discussion emphasises that successful research and development are critical to making hydrogen and fuel cells available at a competitive cost within a reasonable time, and that significant uncertainties surround these developments. A consideration of the role of alternative technology options and energy policies to mitigate emissions and ensure energy supply is essential to assess the real potential of hydrogen as an energy carrier. This study offers a quantitative assessment of the possible role of hydrogen and fuel cells in energy scenarios for the next few decades, building on consensus stakeholder assumptions on future developments for energy technologies and policies. It includes quantitative estimates of the costs and benefits, and looks at the policy issues associated with the use of hydrogen and fuel cells in energy applications.

The study focuses on three principal objectives:

- Quantifying prospects for technical improvement and cost reduction for hydrogen and fuel cells.
- Exploring technical, economic and policy issues for a transition to a hydrogen energy system.
- Analysing the long-term perspectives of a fully developed market for hydrogen and fuel cells.

It aims to address topics and questions such as:

- *What are the promising technologies for hydrogen production, storage and use?*
- *Is transport the most attractive market for hydrogen and fuel cells?*
- *The role of hydrogen in stationary applications.*
- *The policies and measures to speed up the commercialisation of hydrogen.*
- *What are the transition costs and infrastructure investment?*
- *What impact hydrogen and fuel cells might have on CO_2 mitigation?*
- *What impact hydrogen and fuel cells might have on the security of energy supply.*
- *Policies and potential market penetration of hydrogen and fuel cells in various regions.*

The study has been carried out using the IEA Energy Technology Perspectives (ETP) model. This is a MARKAL-type model (Loulou *et al.*, 2004; Tosato, 2005) of the global energy system that was developed at the IEA (Gielen and Karbuz, 2003 and IEA, 2004c) to analyse technology policies and to support decision making in the energy sector. The model includes: 15 world regions with energy trading between regions, a detailed description of the energy system in each region, with energy demand and supply, fuels, carriers and technologies; a database with more than 1500 demand/supply technologies with performance, costs, emissions; and a proper characterisation of technology learning for emerging technologies. Given the energy systems and technology mix in the base year, the model analyses their evolution over a time horizon to 2050 and provides cost-optimal configurations under selected assumptions for energy policies and technology development.

This study was conceived within the framework of the activity of the IEA Hydrogen Co-ordination Group (HCG). The Group was established at the beginning of 2003 to co-ordinate hydrogen and fuel cell policy and R&D efforts across IEA Member countries. As part of this effort, the IEA published, after input from HCG members, a review of the R&D activities and policies in IEA member countries (*Hydrogen & Fuel Cells - Review of the National R&D Programmes* [IEA, 2004b]). Using the expertise available in the IEA Implementing Agreements, namely the Hydrogen and the Advanced Fuel Cells Implementing Agreements, the HCG has also carried out a review of the priorities and gaps in hydrogen and fuel cells R&D.

In order to provide policy makers with an insight into the potential of hydrogen and fuel cells in future energy scenarios, the HCG asked the IEA Secretariat to carry out this study using the IEA ETP model. The work was financially supported by ten HCG countries: Australia, Austria, Canada, France, Germany, Japan, the Netherlands, Spain, the United Kingdom and the United States. A first draft of this report was extensively discussed by member country representatives and international experts at the ad-hoc workshop organised by the IEA on 28-29 June 2005.

The goal of this study is to provide quantitative information to policy makers about the current state of hydrogen and fuel cell technologies, their current costs, their potential cost reductions and the role these technologies could play in the future under a wide range of assumptions. The purpose of the study is not to forecast what is likely to happen in the future, but to help policy makers to make informed decisions on energy and technology policies, and shape the future of hydrogen and fuel cells.

This report consists of two parts. The first part, comprising Chapter 2, 3 and 4, includes an assessment of the cost and performance of hydrogen and fuel cell technologies, along with prospects for their future development. These chapters offer a very detailed overview of the range of hydrogen and fuel cell technologies, the key RD&D areas, and potential areas of future development. Chapter 2 deals with hydrogen production, transportation, distribution and storage technologies. Chapter 3 focuses on fuel cells and hydrogen end-uses technologies, while Chapter 4 discusses competing technology options. The second part of the study, comprising Chapter 5, 6, 7 and 8, deals with the results of the model analysis. Chapter 5 describes the structure of the analysis and includes a discussion of two basic scenarios that define the energy context. They depict the reference, business-as-usual development of the energy system (BASE scenario), and map key technologies and parameters for hydrogen and fuel cells (MAP Scenario). Chapter 6 discusses the results of a sensitivity analysis aimed at quantifying the effect of varying individual parameters and assumptions for technology and policy. Chapter 7 presents the results of four different scenarios. These scenarios are based on different combinations of key parameters and assumptions, and represent four cost-optimal configurations of future energy systems including hydrogen and fuel cells under different conditions and assumptions. Chapter 8 is the final chapter and discusses the conclusions of the study.

Prospects for Hydrogen and Fuel Cells is the second publication of the IEA Energy Technology Analysis series. The first, *Prospects for CO_2 Capture and Storage*, was published in December 2004 (IEA, 2004c).

Chapter 2.
HYDROGEN TECHNOLOGIES

This chapter provides an assessment of the technical and economic characteristics of the technologies for hydrogen production, transportation, distribution and storage. Chapter 3 provides similar technical and cost information for fuel cells and other hydrogen end-use technologies. These chapters are essential reading to understand the range of hydrogen technologies on offer, their performance and costs, key RD&D areas and other potential developments. The data presented in Chapter 2 and Chapter 3 have been used to quantitatively assess hydrogen potentials using the IEA ETP model.

HIGHLIGHTS

- Hydrogen can contribute to the security of energy supply because in principle it can be produced from any primary energy source, using a number of different processes. Hydrogen can also be a CO_2-free energy carrier and offer benefits in terms of emission mitigation if it is produced from coal and gas with CO_2 capture and storage, from renewable energy, or from nuclear energy.
- Some 40 million tonnes of hydrogen a year are currently produced using established technologies, primarily natural gas reforming but also coal gasification and water electrolysis. However, to produce cost-effective hydrogen for energy use, these technologies need higher efficiencies, significant cost reductions and the development of cheap and safe techniques for CO_2 capture and storage.
- Research efforts are focused on high-efficiency gas reforming, coal gasification in integrated gasification combined-cycle (IGCC) plants for the co-production of electricity and hydrogen, and electrolysis at high temperature and pressure. The large-scale centralised hydrogen production from natural gas and coal require further RD&D efforts, especially to make available cheap and safe techniques for CO_2 capture and storage. A number of emerging technologies such as water splitting using solar and nuclear heat, biomass gasification, photo-electrolysis and biological processes are also being developed, but are still far from being commercialised.
- In the early market introduction phase, decentralised small-scale electrolysis and natural gas reforming (without CO_2 capture and storage) appear as the technologies of choice to produce hydrogen as they do not require expensive distribution systems. However, decentralised plants have in general lower efficiency and higher costs than those of centralised plants. Also, capture of CO_2 emissions in small-scale reformers is not likely to be feasible. Electrolysis is even more expensive than natural gas reforming. In addition, the surplus of CO_2-free electricity for hydrogen production will probably be limited to a few regions even in the long term.
- Currently, the cost of decentralised hydrogen production may exceed USD 50/GJ H_2. While sensitive to electricity prices and natural gas prices, the cost of decentralised hydrogen production from electrolysis may be reduced to below USD 20/GJ H_2 by 2030 and that of natural gas reforming to below USD 15/GJ H_2. Various centralised production options promise hydrogen at less than USD 10-15/GJ H_2. The projected cost of hydrogen from

coal gasification with CO_2 capture and storage could be even lower, at below USD 10/GJ H_2. In the long term, the costs for high-temperature water splitting could range from USD 10/GJ H_2 to USD 20/GJ H_2 using nuclear and solar heat, respectively. Higher costs are projected for other advanced technologies.

- Hydrogen can fuel combustion engines and turbines, but it offers its full benefits in terms of energy efficiency, CO_2 and pollutants emissions when used in fuel cells. The use of hydrogen in fuel cell vehicles could solve both the problem of oil-dependence and emissions in the transport sector. Stationary uses for combined heat and power production are also potential applications for hydrogen fuel cells, but non-hydrogen fuel cells appear a more competitive option in this market segment.

- The global character of the car industry is such that standards for hydrogen production, distribution, storage, safety and quality need to be established before a full-scale hydrogen infrastructure is developed. The identification of a suitable and cost-effective on-board storage system for fuel cell vehicles is an urgent issue, as it may have an impact on the choice of hydrogen infrastructure.

- No existing on-board storage option meets the technical and economic requirements for commercialisation. Gaseous storage at 350-700 bar and liquid storage at -253°C are commercially available, but costly options. The cost of the tank ranges from USD 600-800/kg H_2 and the electrical energy required for compression and liquefaction is more than 12% and 35% of the hydrogen energy content, respectively. Solid storage offers potentially decisive advantages, but it is still under development, with a number of materials being investigated. At present, without further breakthroughs, gaseous storage at 700 bar seems the technology of choice for passenger cars.

- Where the production of hydrogen is centralised, the transportation and distribution costs, and the refuelling cost for transport vehicles, add considerably to the total hydrogen supply cost. These costs are in the range of USD 5-10/GJ /GJ H_2 for large-scale supply systems, but may be higher during the initial development phase. Hydrogen transportation by pipeline is also expensive. In comparison with natural gas, hydrogen pipelines are twice as expensive in terms of investment cost and require five times more energy. Considerably more expensive is the transportation and distribution of liquid hydrogen.

- The global investment in the supply infrastructure to distribute hydrogen for road transport could be in the order of several hundred billion US dollars. If centralised production is adopted, the cost of a hydrogen pipeline supply system for the transport sector might be USD 0.1-1.0 trillion. The *incremental* investment cost for hydrogen refuelling stations over conventional stations would be somewhere between USD 0.2-0.7 trillion (for centralised and decentralised production respectively).

- A full hydrogen economy for both transport and stationary applications would require pipeline investment in the order of USD 2.5 trillion, the bulk of which would be needed to reach commercial and residential customers. Assuming early retirement and partial replacement of the existing gas supply system, a significant part of this cost would be an *incremental* cost.

- Despite the considerable uncertainties surrounding these estimates, the hydrogen investment should be seen in the light of the global investment of USD 16 trillion that would be required for the overall energy supply system until 2030 (IEA, 2004a). Hydrogen investment would add substantially to the total investment cost for the energy system, but should not be considered as a deterrent for a transition to hydrogen.

All figures in this publication are in SI units and the energy content of hydrogen is expressed in terms of the lower heating value (LHV). This means that the energy contained in the gaseous water product of combustion (the energy that is needed to evaporate the water) is not taken into account. The difference is significant: 120 GJ/t (LHV) vs. a higher heating value (HHV) of 140 GJ/t. Using the LHV value is consistent with the conventions used in all IEA energy statistics. It does not affect the evaluation of the overall hydrogen energy chain. However, other studies can be based on HHV, which results in different efficiency figures throughout the energy chain to those presented here on the basis of LHV.

Hydrogen production

Hydrogen can be produced from fossil fuels, nuclear and renewable energy by a number of processes, such as water electrolysis, natural gas reforming, gasification of coal and biomass, water splitting by high-temperature heat, photo-electrolysis, and biological processes. Of the total hydrogen production of about 5 EJ per year, 40% is used in chemical processes, 40% in refineries and 20% for other uses. In 2003, 48% of the global demand for hydrogen was produced from natural gas, 30% from oil and recovered from refinery/chemical industry off-gases, 18% from coal, and 4% from electrolysis. Most of this hydrogen is produced on-site in refinery and chemical plants for captive, non-energy uses. The currently established technologies for producing hydrogen require significant improvements in their technical and economic performance (efficiency and costs) if hydrogen is to be produced for energy use. At the beginning of 2003, the price of pipeline-delivered compressed hydrogen in the United States ranged from USD 7/GJ to USD 30/GJ. For compressed hydrogen delivered in "tube trailers" the price was in the range of USD 90-100/GJ.

Water electrolysis and natural gas reforming are proven technologies that could be used in the early transition phase to hydrogen as an energy carrier. Electrolysis is a costly process used to produce high-purity hydrogen, while the cheaper and more efficient process of gas reforming is used for large-scale production where quality is not such an issue. Depending on the results of R&D currently underway, in the medium to long term hydrogen may be produced by natural gas reforming or coal gasification in centralised plants with carbon dioxide capture and storage (CCS). Other hydrogen production processes from renewable and nuclear sources are still a long way from being commercially viable. The production of hydrogen from biomass faces feed preparation and logistics challenges, and is likely to be competitive only on a large scale. To be economic, thermo-chemical water splitting using high-temperature heat needs the development of new materials for the process equipment, cost reductions, and access to cheap supplies of high-temperature heat (*e.g.* from nuclear or solar energy). The production of hydrogen from photo-electrolysis (photolysis) and from biological production processes are both at an early stage of development.

At present, the production of hydrogen at both a centralised and decentralised level is being considered. However, certain feedstock and technologies are more suited to centralised hydrogen production, while others are more suited to decentralised production. The optimal combination of feedstock and technologies for centralised and decentralised production needs to be analysed in detail.

The cost of current large-scale production of hydrogen from fossil fuels at centralised facilities is too high for hydrogen to be viable as an energy carrier. Natural gas reforming requires further RD&D in order to lower costs, increase the efficiency and enhance the flexibility of the process. Improved catalysts, adsorption materials, separation membranes or purification systems are also needed to produce hydrogen that is suitable for all types of fuel-cell 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. The cogeneration of hydrogen and electricity from coal in centralised IGCC plants with CCS has the potential to produce cost-effective, CO_2-free hydrogen from coal. Ongoing CCS demonstration projects at an industrial scale are producing promising results, but considerably further RD&D is needed (IEA, 2004c) to prove and commercialise this technology. In the future, centralised hydrogen production from high temperature processes based on nuclear or renewable energy could avoid the need for CO_2 capture and storage. However, for centralised production to prove the most economic means of hydrogen production, cost-effective hydrogen transportation and distribution infrastructure will need to be developed.

Today's decentralised production of hydrogen is based on water electrolysers and small natural gas reformers. Small-scale reformers are currently commercially available, with several demonstration projects testing units in industrial applications. In recent years, suppliers have considerably improved reformers' compactness (10×3×3 m) and capacity (500-700 Nm^3/hour, equivalent to 5.5-7.5 GJ/hour), but further RD&D is needed to reduce costs and increase the efficiency of production. Distributed production minimises the need for expensive transportation infrastructure, but this is offset to some extent by the generally higher costs per unit of capacity and lower efficiency of smaller distributed production plants. In addition, CCS from small natural gas reformers is probably too difficult and costly to be feasible. In the long term, photo-electrolysis, water splitting by solar heat and biological processes could be used for decentralised hydrogen production from renewable sources.

Hydrogen from electrolysis

Electrolysis is a well-known process that converts water into hydrogen and oxygen using electricity. Electrolysis opens the door to hydrogen production from any primary energy source that can be used for electricity generation. Currently two types of electrolysers exist: the alkaline electrolysers that use KOH solutions and the less mature polymer electrolyte membrane[2] (PEM) technology. PEM electrolysers are, in simple terms, fuel cells operated in reverse mode. Alkaline electrolysis based on a KOH water solution as a liquid electrolyte is a mature industrial technology. It is well suited to producing hydrogen for stationary applications with operating pressures up to 25 bar. The major R&D challenges facing alkaline electrolysers are to improve their efficiency, lifetime and costs. In PEM electrolysis, the electrolyte is a solid, acidic polymer membrane and no liquid electrolyte is required. Major advantages include the absence of the corrosive KOH electrolyte, a compact design, high current densities and high operation pressures (up to several hundred bar). The main drawback in the current PEM systems is the limited membrane lifetime. It is expected that the PEM electrolyser performance (in terms of cost, capacity, efficiency and lifetime) can be improved by new materials and new cell stack design. New technology variants are under development, such as high temperature and high pressure electrolysers. The theoretical characteristics of different electrolysis options are given in Table 2.1.

Table 2.1

The Theoretical Efficiency of Electrolysis at Various Temperatures and Pressures

P (bar)	T (°C)	Theoretical electricity use (GJ/GJ H_2)	Theoretical heat use (GJ/GJ H_2)	Theoretical total energy use (GJ/GJ H_2)	Theoretical overall efficiency (%)
1	25	0.98	0.20	1.18	84.6
1	1000	0.74	0.63	1.37	73.1
400	25	1.07	0.20	1.27	78.6

Source: Prince-Richard, 2004.

2. Also known as Proton Exchange Membrane fuel cells.

The theoretical maximum efficiency of electrolysers is about 85%, but current electrolysers are in general less efficient. As electricity costs are the main operating cost of electrolysers, the main RD&D target is to increase their electrical efficiency. The current efficiency of decentralised alkaline electrolysers including auxiliaries, but excluding hydrogen pressurisation, is about 40%, while large-scale centralised systems achieve about 50% (Schuckert, 2005). Hydrogen pressurisation requires substantial amounts of electricity and its consideration will reduce the electric efficiency substantially. Other sources suggest a somewhat higher efficiency value of 63.5% (LHV) for current 20 kg/hr (120 cars a day) decentralised electrolysers operating at 11 bar, including auxiliary loads other than compression (NRC, 2004, p. 220). This significant efficiency difference (40% vs. 63.5%) may be explained by differences between working and test conditions. The efficiency of electrolysers also depends on the current density. PEM electrolysers operating at low current density can approach the theoretical efficiency limit. However, the required additional capital cost currently exceeds the electricity cost savings. Lower current densities may become economic in the future if electrolyser capital costs decrease.

High-temperature and high-pressure electrolysis may offer efficiency advantages. Although, the heat energy consumption of the electrolysis process slightly increases when operating at a higher temperature, the electricity requirement decreases. Therefore, high-temperature electrolysis may offer a favourable energy balance if high-temperature residual heat is available from other processes. Steam electrolysis at 800-1000 °C may achieve high efficiency values. High pressure electrolysis can save part of the energy required to pressurise hydrogen. The German research centre Forschungszentrum Jülich has produced a 5 kW high-pressure electrolyser prototype, which is able to produce hydrogen at 120 bar at an efficiency similar to that of the low-pressure model (Jansen *et al.*, 2001). The Avalance Hydrofiller is a commercially available high-pressure unipolar alkaline electrolyser that is able to reach pressures of up to 690 bar and requires an energy input of 5.1-5.4 kWh/Nm^3H_2, which is equivalent to 55-58% electric efficiency (Ivy, 2004). A further option is the Solid Oxide Electrolyser Cell (SOEC), based on Solid Oxide Fuel Cells (SOFCs), which normally operate at 700-1000 °C. The main R&D issues facing SOECs are improvements in materials and thermal stress limits in the ceramic materials. The characteristics of various electrolysers are compared in Table 2.2.

The current cost of an electrolyser system capable of fuelling 120 cars a day (roughly a 700 kW system providing 20 kg/hr) is about USD 1 000/kW, with appropriate scaling factors to be considered for smaller systems (NRC, 2004, p. 220). The cost of electrolysers based on fuel cells operated in reverse mode are expected to decline dramatically to some USD 125/kW over the next 15 to 20 years, as the cost of PEM automotive fuel cells drops to USD 50-100/kW (NRC, 2004).

In terms of hydrogen production cost (USD/GJ H_2), economies of scale due to larger unit capacity and higher production volume should result in hydrogen cost falling to half, or one-fifth, of today's cost (Figure 2.1). Figure 2.1 suggests that the investment cost per unit of capacity for systems of more than 50 cars per day are virtually constant.

The levelised capital cost of a reference decentralised electrolyser system in 2010 would amount to some USD 10/GJ H_2. This is based on assuming USD 1 000/kW, annual operation and maintenance costs of 4% of the initial capital investment, a 15 year life span and a 10% discount rate. Assuming that capital costs fall in-line with expectations in the long term to some USD 125/kW, these capital costs would drop to USD 1.3/GJ H_2. In comparison, the annualised capital cost of high-pressure electrolysers would amount to USD 28/GJ H_2 in 2010, while the potential for reductions in their costs over time is not clear at this stage.

Assuming an average electricity cost of USD 0.035/kWh, the electricity cost in 2010 for a 63.5% efficient electrolyser would be USD 15.4/GJ H_2. Assuming an efficiency of 80% in 2030 implies

Table 2.2

Characteristics of existing and advanced electrolysers

Technology	Conventional electrolyser	Advanced alkaline electrolyser	Inorganic membrane Electrolyser	PEM electrolyser	SOFC High temp. steam electrolyser
Development stage	Commercial large scale units	Prototypes and commercial	Commercial units	Prototypes and commercial units	Lab.-stage and commercial units
Cell voltage (V)	1.8-2.2	1.5-2.5	1.6-1.9	1.4-2.0	0.95-1.3
Current density (A/cm^2)	0.13-0.25	0.20-2.0	0.2-1.0	1.0-4.0	0.3-1.0
Temperature (°C)	70-90	80-145	90-120	80-150	900-1 000
Pressure (bar)	1-2	Up to 120	Up to 40	Up to 400	Up to 30
Cathode	Stainless steel or Ni	Catalytic or non-catalytic active Ni catalyst	Spinel oxide based on CO	C- fibre and Pt	Ni
Anode	Ni	catalytic or non-catalytic active Ni	Spinel oxide based on CO	Porous Ti and proprietary catalyst	Ni-NiO or Perovskite
Gas separator	Asbestos 1.2-1.7 Ohm/cm^2	Asbestos < 100°C; Teflon bonded PBI-K-titanate > 100 °C; 0.5-0.7 Ohm/cm^2	Patented polyantimonic acid membrane 0.2-0.3 Ohm/cm^2	Multilayer expanded metal screens	None
Electrolyte 25-35%	25-40% KOH	14-15% KOH	Perfluorosulfonic KOH	Solid Y_2O_3 acid membrane 10-12 mils thick 0.46 Ohm/cm^2	stabilised ZrO_{380}
Cell efficiency ($GJ\ H_2/GJ$ el)	66-69	69-77	73-81	73-84	81-86
Power need (kWh/Nm^3H_2)	4.3-4.9	3.8-4.3	4.8	3.6-4.0	2.5-3.5
Players	Stuart, Norsk Hydro Norsk Hydro, Teledyne	Stuart, FZ Juelich	Stuart	Stuart, Hamilton Sunstrand, Proton Energy, Hydrogenic, Fuji, Avalance	LLNL, Technology Management Inc.

Source: Prince-Richard, 2004 and Stuart, 2005.
Note: The figures do not account for the energy losses in AC/DC conversion or the electricity use for water ionization (together a few percentage points).

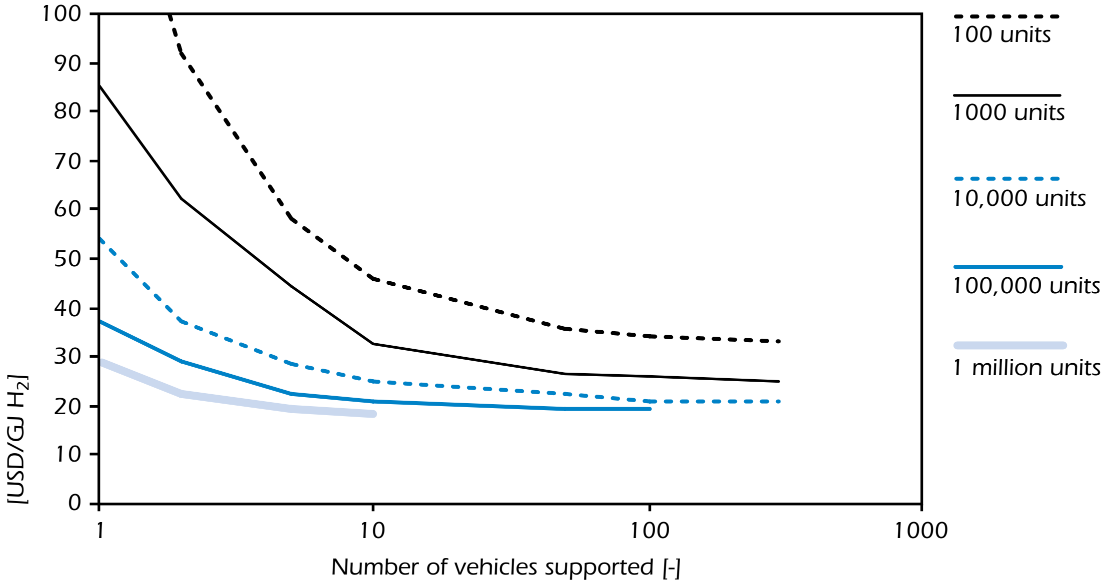
that this cost would drop to USD 12.2/GJ H_2. To these variable costs an additional USD 4/GJ H_2, dropping to USD 2/GJ H_2 in 2030, needs to be added for the hydrogen compressor, storage and dispenser, plus USD 0.7/GJ H_2 for compressor electricity[3].

The cost structure for hydrogen production in 2030, based on high production volumes, is given in Figure 2.2 for a small-scale home system (one or two vehicles) and a large-scale refuelling station (100 vehicles per day).

3. About 7% of the energy content for compression from 15 to 800 bar and up to 14% for compression from 1 to 800 bar (Bossel et al., 2003).

Figure 2.1

Hydrogen production cost vs. electrolyser capacity and production volume

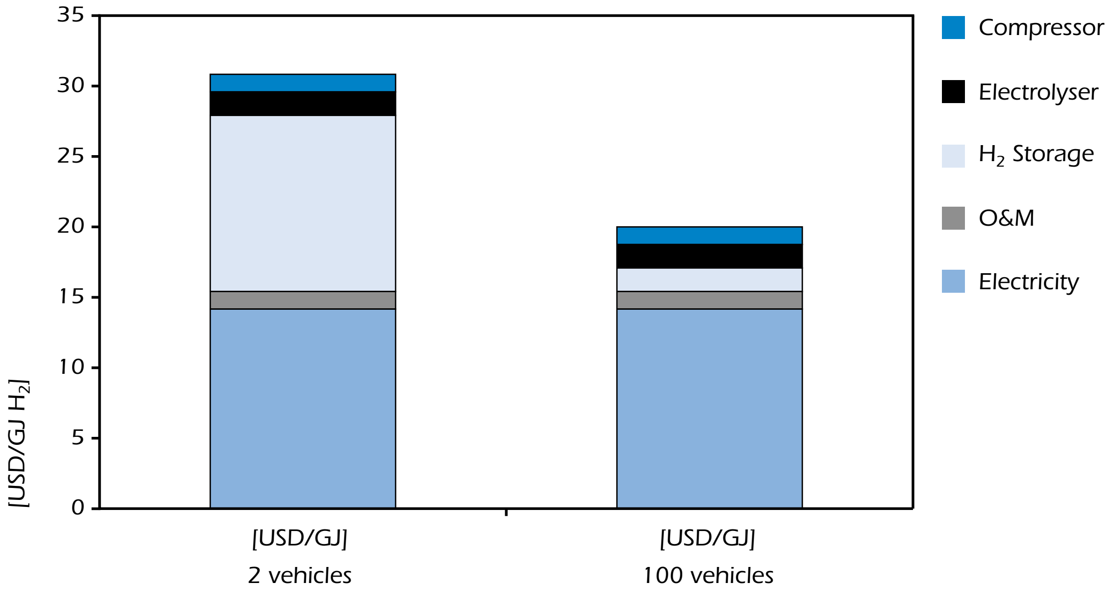


Source : Thomas et al., 2004.

Key point: High-capacity centralised electrolysis at high production volumes can result in a cost reduction factor of 2 to 5

Figure 2.2

Hydrogen production cost breakdown, 2030



Source: Prince-Richard, 2004, p. 99.

Key point: H_2 storage costs matter for residential electrolysers, but not for large-scale refuelling stations

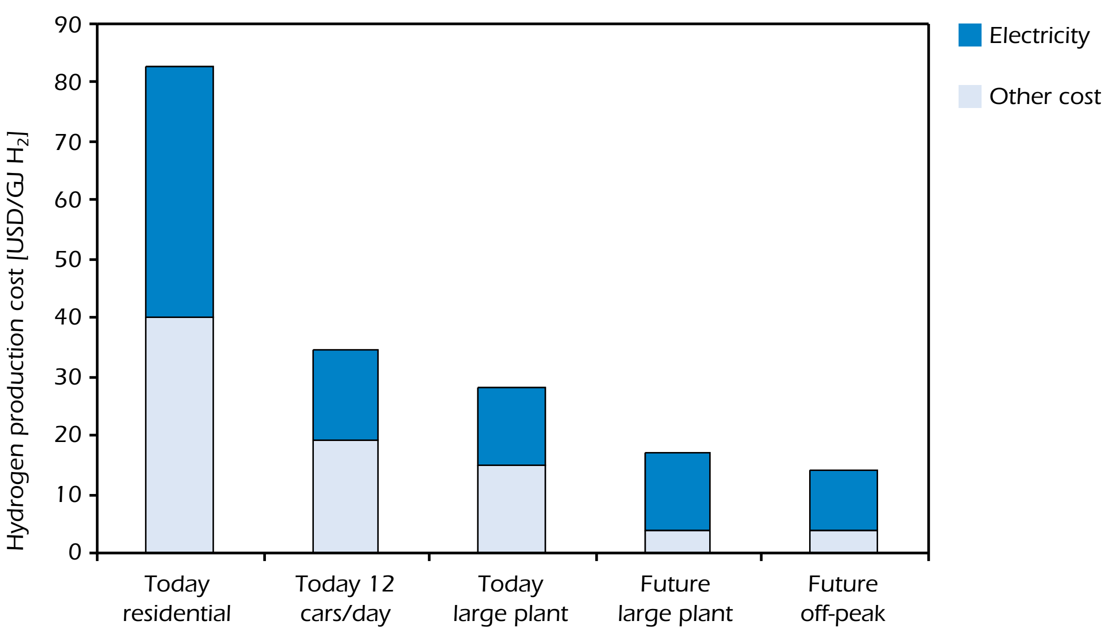
In summary, the cost of producing hydrogen from electrolysis is estimated to range between USD 34.4/GJ in 2010 and USD 17/GJ in 2030 (Figure 2.3). Even lower costs may be achieved if off-peak electricity can be used. However, in 2004, the only OECD countries with an industrial electricity price of USD 0.035/kWh or less were Australia, New Zealand and Norway. The highest price, in Japan, was USD 0.115/kWh. In all OECD countries, residential electricity prices are USD 0.03-0.10/kWh higher than industrial prices. In addition, incremental electricity generation from CO_2-free primary energy sources, or with CCS, is unlikely to be available at USD 0.035/kWh.

Both centralised and various types of decentralised electrolysis systems have been included in the model analysis in the second part of this study. The centralised systems are assumed to have a 3% higher efficiency and 25% lower capital cost than the decentralised systems. For the decentralised production of hydrogen, four systems have been considered (alkaline, PEM fuel cells, high temperature and high-pressure systems), operating in both continuous and diurnal (*i.e.* using off-peak electricity) modes.

While centralised large-scale electrolysis seems an obvious choice from the viewpoint of low capital costs per unit of production capacity, it may not be the best option for the transition phase, as the refuelling network might be too scattered to encourage further uptake when only a small share of the vehicle stock will be fuelled by hydrogen. However, significant reductions in the capital cost of electrolysers will reduce the incentive for large-scale centralised systems and favour decentralised electrolysis instead, perhaps eliminating this potential problem.

Figure 2.3

The current and future levelised cost of hydrogen from electrolysis



Note: Assuming a residential electricity price USD 0.10/kWh, off-peak of USD 0.03/kWh and others USD 0.035/kWh.

Key point: H_2 costs can be halved through economies of scale and the use of off-peak electricity

Hydrogen from fossil fuels

Natural gas reforming and coal gasification in combination with water-gas shift are mature technologies for hydrogen production from fossil fuels. Both processes emit significant amounts of CO_2 and will require CO_2 capture and storage if they are to produce emission-free hydrogen. In refineries and the chemical industry, natural gas reforming is widely used to produce hydrogen on a large scale. Small-scale reformers are currently being used in demonstration refuelling stations for automotive applications (see Annex 4 for existing hydrogen refuelling stations). The future production of hydrogen from coal gasification builds on IGCC power plants, a certain number of which are currently operated in various countries either as demonstration or first-of-kind commercial plants. In this study, special attention is given to the cogeneration of electricity and hydrogen from coal in IGCC plants. Although the cost of such plants is high in comparison with conventional coal-fired power plants, they have the potential to produce electricity and hydrogen efficiently, and to allow cheap CO_2 separation and capture. The captured CO_2 could then be stored underground, for example in deep saline aquifers. The feasibility of the safe and permanent underground storage of CO_2 is currently being tested in various large-scale demonstration projects (IEA, 2004c).

Production from natural gas

Hydrogen can be produced from natural gas by three processes: Steam Methane Reforming (SMR), Partial Oxidation (POX) and AutoThermal Reforming (ATR). There are different variants of each of these processes and new variations on these technologies are under development. The processes are based on one or more chemical reactions that are either endothermic or exothermic (Table 2.3). Appropriate balancing of these reactions can result in processes that require little heat exchange.

In the steam reforming process, methane reacts with water vapour at 700-850°C and 3-25 bar to produce hydrogen and carbon monoxide. The carbon monoxide is then converted into CO_2 and H_2 through the water-gas shift reaction. In the partial oxidation process, methane reacts with oxygen to produce hydrogen and carbon monoxide. Carbon monoxide further reacts with steam to produce additional H_2 and CO_2. Autothermal reforming is a balanced combination of steam reforming and partial oxidation at 950-1100°C and 100 bar. For large-scale units, SMR offers efficiencies of up to 85% (excluding hydrogen pressurisation), low levels of emissions and low costs. ATR requires an advanced reactor design and might in the future be able to offer high efficiencies, especially for small-scale units.

Table 2.3

Reactions for producing hydrogen from fossil fuels

	Process	Enthalpy (kJ/mol)
Steam reforming	$CH_4 + H_2O \rightarrow CO + 3H_2$ $C_nH_m + n\ H_2O \rightarrow nCO + (n + m/2)\ H_2$ $CO + H_2O \rightarrow CO_2 + H_2$	-206 -1 175 41
CO_2 reforming	$CH_4 + CO_2 \rightarrow 2\ CO + 2H_2$	-247
Autothermal reforming	$CH_4 + {}^3/_2O_2 \rightarrow CO + 2H_2O$ $CH_4 + H_2O \rightarrow CO + 3\ H_2$ $CO + H_2O \rightarrow CO_2 + H_2$	520 -206 41
Catalytic partial oxidation	$CH_4 + O_2 \rightarrow CO_2 + 2H_2$	38

Source: Larsen *et al.*, 2004.

Note: A minus indicates a reaction that releases heat and a plus indicates a reaction that requires heat from an external source.

For moderate levels of hydrogen demand with a low geographical concentration, decentralised production from natural gas could be cheaper than large-scale centralised production, because it does not require an extensive transportation and distribution infrastructure. An important disadvantage is that CO_2 capture and storage from small plants would be very expensive. Despite this, natural gas reforming is likely to be the best option to supply hydrogen during the early market introduction phase. The main characteristics of decentralised technologies are given in Table 2.4. In general, the efficiency of decentralised plants is 5 to 10 percentage points lower than those of centralised units.

Table 2.4

Decentralised reforming technologies

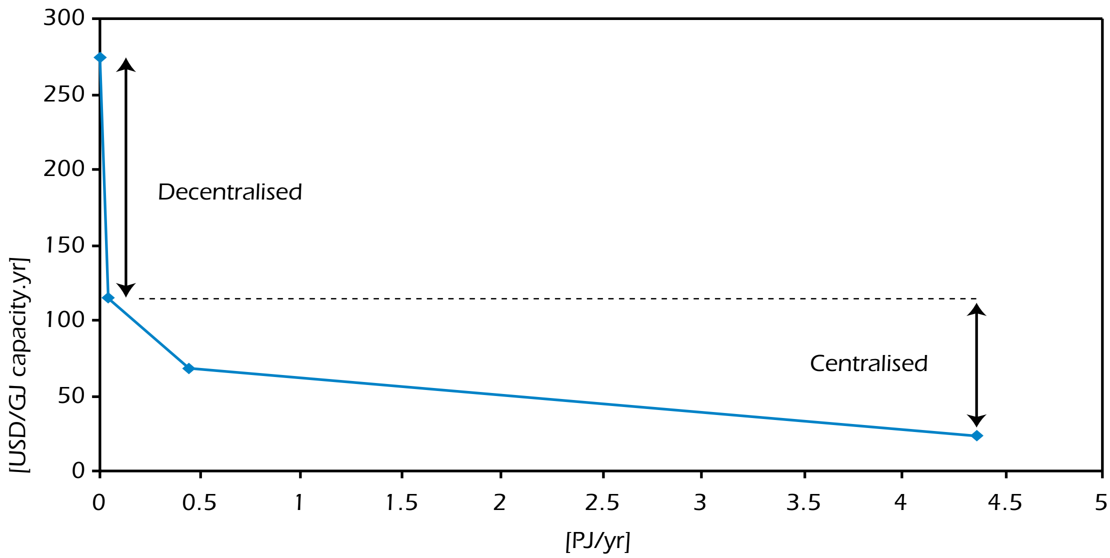
Technology	Conversion efficiency (%, LHV)	Investment cost (USD/GJ.yr)
Steam methane reforming	71-76	125 (6)
Partial oxidation	66-76	NA
Autothermal reforming	66-73	NA
Potential of novel reforming technologies	>75	NA

Source: Ogden, 2002 and NRC, 2004.
Note: Figures in brackets indicate the future potential (2020-2030). Pressurisation not included.

In general, the reformer cost per unit of capacity declines as the unit size increases. It can be seen from Figure 2.4 that the investment cost of a 300 cars/day fueling station (0.04 PJ of H_2 per year) would be around USD 100/GJ. Smaller systems than this are estimated to be up to 3-4 times

Figure 2.4

Investment costs for steam reforming units vs. capacity



Source: Mintz, 2003.
Note: H_2 pressurisation is not included.

Key point: Investment costs for decentralised steam reforming are up to 10 times higher than for large-scale units more expensive. However, while potential improvements in large-scale steam reformers are limited, it is estimated that the new small-scale reformers currently under development have a significant cost reduction potential (Table 2.5).

Table 2.5

The current and future costs and efficiency of hydrogen production from natural gas

Unit size (PJ H_2/yr)	Large scale 50		Medium scale 1		Small scale 0.02	
	Gaseous H_2 78 bar		Liquid H_2		Gaseous H_2 340 bar	
	Current	Future	Current	Future	Current	Future
Investment w/o CCS (USD/GJ yr)	9.4	6.8	21	16	42	22
Investment with CCS (USD/GJ yr)	11.9	8.1	28	22		
Thermal efficiency w/o CCS, LHV (%)	72.5 (76.2)	76.9 (80)	46.1	53.1	46.7 (60)	59.6 (70)
Thermal efficiency with CCS, LHV (%)	61.1 (62)	70.0 (78)	43.4	49.0		
Natural gas price (USD/GJ)	3	3	3	3	4	4
H_2 cost w/o CCS (USD/GJ)	5.5	4.9	9.6	8.1	13.5	10.0
H_2 cost with CCS (USD/GJ)	6.7	5.5	11.1	9.4		

Source: NRC, 2004.
Note: Data include H_2 pressurisation, where applicable. The figures in brackets present the efficiency excluding H_2 and CO_2 pressurisation. Electricity process inputs for pressurisation have been translated into primary energy equivalents assuming the efficiency of electricity production from natural gas to be 55%.

Centralised production from coal gasification

Hydrogen can be produced from coal through an endothermic gasification reaction that produces a gas mixture of hydrogen (H_2), carbon monoxide (CO), carbon dioxide (CO_2), methane (CH_4), and other components depending on the temperature at which the reaction occurs. If gasification takes place at temperatures above 1000 °C, proportionately more CO and H_2 is produced. The carbon monoxide can then be converted into CO_2 and further H_2 through a water-gas shift reaction at high temperatures. In modern hydrogen plants, the CO concentration is reduced to 0.2% in a second, low-temperature catalytic reaction step. The resulting mixture of H_2, CO_2 and contaminants can be separated using physical absorption processes. In addition to hydrogen, the final product of this process is a relatively pure CO_2, which is ready for pressurisation and storage. However, further hydrogen treatment may be needed to reduce the residual CO concentration in the hydrogen to levels suitable for PEM fuel cells.

Coal gasification, although a complex process, is a mature and cost-effective technology. Some 385 gasifiers (half of which are coal-fed), with a total capacity of 46 GW, are in operation in more than 117 projects world wide (Childress, 2004). In general, hydrogen from coal gasification is more expensive than hydrogen from natural gas reforming at gas prices of USD 3-5/GJ, but may become competitive as gas prices increase. Coal gasification needs oxygen instead of air to reduce dilutants and provide a concentrated stream of CO_2. One of the reasons for this is that pure oxygen is used for the reaction. The production of oxygen is currently based on cryogenic separation which is a costly and energy intensive process. New methods under development may increase the production efficiency and reduce the cost of oxygen production. This will, in turn, reduce the cost of hydrogen from coal gasification. Other developments may also reduce the cost of coal gasification, *e.g.* new hydrogen membrane reactors for the water-gas shift reaction may considerably reduce the energy needs for gas separation and CO_2 pressurisation (Mundschau *et al.*, 2005), and would improve conversion of CO into CO_2. However, these membranes are still in early development (Paul and Winslow, 2005).

The production of hydrogen by coal gasification is not suited to decentralised production, because it relies on economies of scale, and CO_2 capture and storage in small-scale systems would be expensive and difficult. However, the large-scale production of hydrogen from IGCC plants appears to be a particularly attractive option for the centralised production of hydrogen. IGCC plants offer the potential for the efficient and flexible cogeneration of electricity and hydrogen from coal, with cheap CO_2 separation for CCS. In recent years, increasing attention has been paid to the co-production of electricity and synfuels (methanol, Fischer-Tropsch diesel and hydrogen) from coal, as these capital-intensive plants offer significant economies of scale, high capacity factors and high levels of overall efficiency (Lange *et al.*, 2001). A study by Sasol points out that co-producing liquid fuels and electricity increases the overall efficiency of energy use by 40% to 50% compared to the same coal-to-liquids plant without the cogeneration of electricity (Steynberg and Nel, 2004). Studies in the United States have focused on the security of supply and emission mitigation benefits of the co-production of synthetic fuels and electricity at IGCC plants (Gray and Tomlinson, 2001).

Table 2.6 summarises the costs and efficiency of the production of hydrogen from coal gasification for current and future plants, with and without CO_2 capture and storage, and with cogeneration in IGCC plants. The current production cost for hydrogen without CCS is more than USD 7 /GJ H_2. With CCS, the current production cost would be in the range of USD 8-10/GJ H_2, while in the future this could drop below USD 7/GJ H_2. The breakdown of the hydrogen production investment cost from coal, including CO_2 capture, is given in Figure 2.5 for a plant with a production capacity of 35 PJ per year. As the CO_2 has to be removed even if it is not captured, the additional investment cost for CO_2 capture is only the cost for CO_2 drying and compression. This represents only 5% of the total investment cost.

A coal-based power plant technology for electricity and hydrogen cogeneration and CO_2 capture and storage, in line with the US FutureGen concept (Williams and Larson, 2003), has been included in the model. The assumption is that 0.6 EJ of H_2 is produced together with 1 EJ of electricity. Previous analyses (Figure 2.6) show the hydrogen production mix as a function of the investment cost of the plant. The IGCC hydrogen production share declines as the IGCC cost increases. Above USD 2 000/kWel these plants are no longer competitive and production from natural gas with CCS replaces the coal based cogeneration plants.

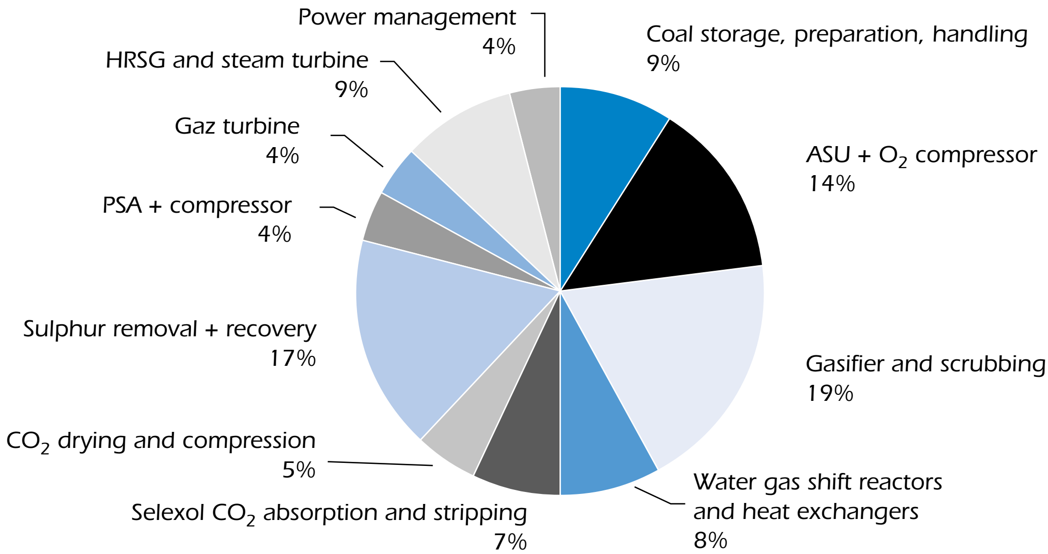
Other production processes from fossil fuels

Hydrogen is also produced from fossil fuels in refinery processes, the production of coke oven gas and in chlorine plants. Refineries both produce their own hydrogen and in some cases purchase hydrogen from third parties. At the refinery, hydrogen is produced in three main ways:

- As a by-product of the catalytic reforming process (which accounts for around half the total refinery production).
- As a by-product of activities at adjacent petrochemical facilities, typically from ethylene crackers.
- By on-site steam reforming units.

Figure 2.5

The investment cost breakdown of hydrogen production from coal (35 PJ/yr of H_2 with CCS)

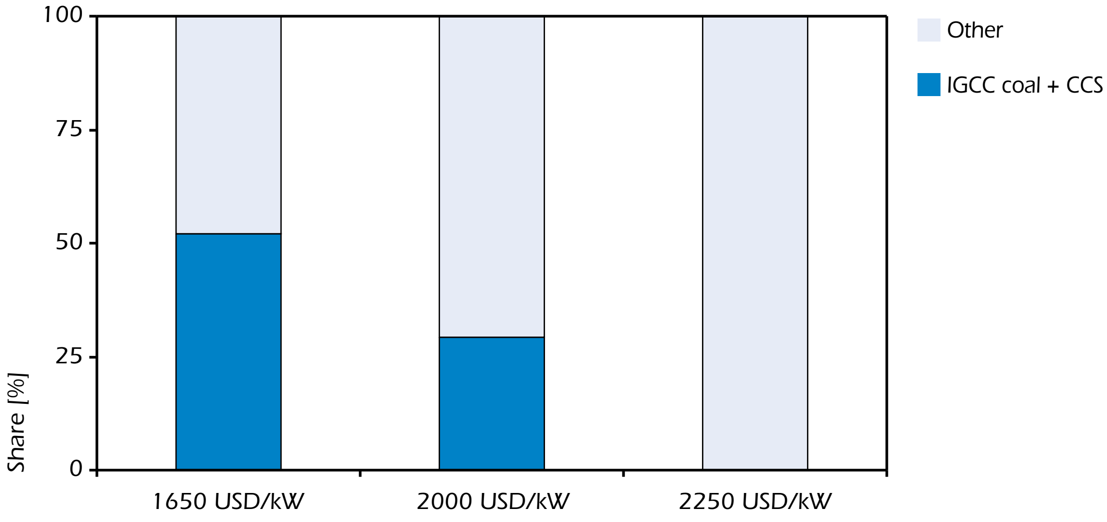


Source: Williams and Larson, 2003.

Key point: The additional cost for CO_2 capture represents only 5% of the total investment cost

Figure 2.6

2050 H_2 production shares as a function of the investment cost of a FutureGen plant



Source: Gielen and Podkanski, 2005.

Key point: High costs for IGCC plants reduce the potential role of IGCCs for H_2 production

Table 2.6

Cost and efficiency of hydrogen production from coal

		Coal input (MW)	Electricity output (MW)	H_2 output (MW)	H_2/El ratio (-)	Capital cost (MUSD/yr)	Capital cost ($/kWe)	Source	Overall (%)	H_2 efficiency (%)	H_2 cost efficiency (USD/GJ)
Texaco O_2-blown gasifier, high-S hard coal	w/o CCS	1 863	78	1 070	13.7	765	9 763	(Williams and Larson, 2003)	61.7	66.8	6.55
Texaco O_2-blown gasifier, high-S hard coal	with CCS	1 863	39	1 070	27.5	807	20 733	(Williams and Larson, 2003)	59.5	62.1	7.29
FutureGen	with CCS	550	275			571	2 076	(DOE, 2004b)			
Coal current	w/o CCS	2 470	-121	1 667		1 152		(NRC, 2004)	62.6	56.6	7.83
Coal future	w/o CCS	2 264	-98	1 667		868		(NRC, 2004)	69.3	64.0	6.19
Coal current	with CCS	2 470	-187	1 667		1 177		(NRC, 2004)	59.9	50.7	8.43
Coal future	with CCS	2 264	-88	1 667		890		(NRC, 2004)	69.7	65.0	6.23
Texaco quench, PSA	w/o CCS	944	20	457	22.4	367	17 990	(Gray and Tomlinson, 2002)	50.6	53.2	7.91
Texaco quench, PSA	with CCS	944	27	415	15.4	417	15 502	(Gray and Tomlinson, 2002)	46.8	50.3	9.48
Advanced gasifier, advanced membrane separation	with CCS	944	25	551	22.1	425	17 000	(Gray and Tomlinson, 2002)	61.0	64.3	7.29
Cogeneration	w/o CCS	1 889	475	520	1.1	910	1 916	(Gray and Tomlinson, 2002)	52.7	83.4	6.64
Cogeneration	with CCS	1 889	358	534	1.5	950	2 654	(Gray and Tomlinson, 2002)	47.2	70.4	9.68
Cogeneration, membrane CO_2 separation	with CCS	1 889	416	534	1.3	950	2 284	(Gray and Tomlinson, 2002)	50.3	77.2	8.38

Assumptions: coal cost USD 1/GJ, an electricity price of USD 0.04/kWh, an annuity of 15%, an O&M cost of 4% and a capacity factor 85%. H_2 produced at 75 bar. The H_2 efficiency is calculated by assuming 45% efficiency for stand-alone electricity production from coal. Coal future refers to a plant built with the best available technology two to three decades from now. The H_2/electricity production ratio allows comparison across designs with different capacities.

The global refinery industry's production capacity of hydrogen amounted to around 2.1 EJ in 2000. This hydrogen is needed to process the crude oil and to improve the characteristics of transportation fuels. The refinery industry's demand for hydrogen is increasing due to the increased processing of heavier crude types and the continued shift of the product mix towards the more hydrogen-rich transportation fuels. In addition, recent legislation in Europe and other regions that requires lower sulphur levels in gasoline and diesel will boost hydrogen demand, as this will require more hydrogen treatment. As a consequence of these trends, refineries will be growing consumers of hydrogen and cannot be considered a source of hydrogen for other uses. However, hydrogen production units that feed refineries and their associated hydrogen transport and distribution system may create economies of scale in hydrogen production and lower hydrogen production costs.

The separation of hydrogen from coke oven gas is being considered, especially in Japan. Coke oven gas is a by-product of the production of coke, both of which are currently used by the steel processing industry. Around 400 m^3 of coke oven gas is produced per tonne of coke. This gas contains around 55% hydrogen on a dry basis, or 29% on a wet basis. One tonne of coke therefore has the potential to yield about 254 m^3 of hydrogen, which is equivalent to around 2.7 GJ H_2. With global coke production of about 350 Mt per year, the potential for hydrogen recovery is therefore about 0.95 EJ per year. This potential could be almost doubled if the coke oven gas is subjected to further processing (Diemer *et al.*, 2004). However, hydrogen would only be produced from coke oven gas if it yielded a higher value to steel producers than its current use in steel processing. Moreover, increased recovery of hydrogen from coke oven gas would imply more natural gas or coal use by the iron and steel industry to make up for the energy shortfall. This would reduce the net CO_2 benefits of hydrogen use substantially. For this reason, this option has not been analysed in more detail.

The electrolytic production of chlorine from salt produces hydrogen as a by-product (3.4 GJ H_2 per tonne of chlorine). Global production capacity of around 50 Mt of chlorine per annum, at some 650 chlorine plants, translates into a production potential 190 PJ H_2. At present, this hydrogen is used on-site for energy recovery. However, as this hydrogen is pure and does not require extensive cleaning for use in FCVs, it could become more attractive to use this hydrogen in FCVs in the future.

Hydrogen from high-temperature water splitting using solar and nuclear heat

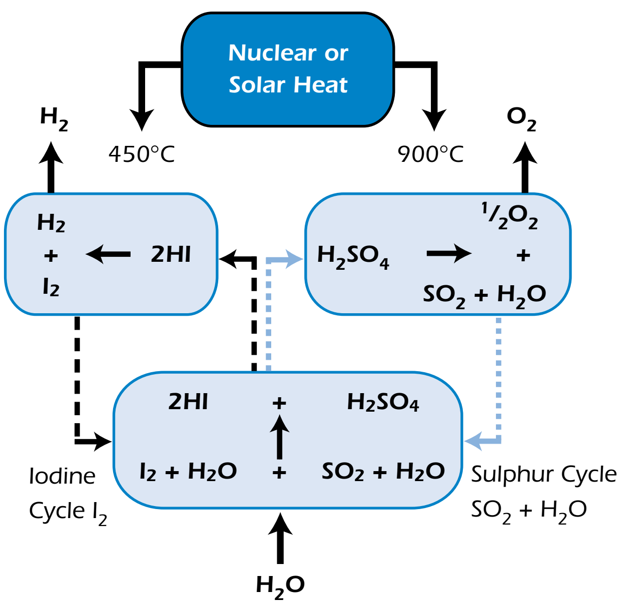
The direct use of high-temperature heat to split water and produce hydrogen has the advantage of avoiding the costly and energy-consuming generation of electricity as an intermediate step in the production of hydrogen. The main problem is that direct water splitting occurs at very high temperatures (above 2 500 °C). However, a number of technologies are currently being researched which aim to reduce the temperature required for the process to below 1 000 °C. They include: thermo-chemical cycles, hybrid thermal/electrolytic decomposition processes, direct catalytic decomposition using ceramic membranes and plasma/chemical decomposition with a CO_2 cycle. In addition to reducing the temperature of the process, research efforts are trying to raise energy efficiency values above 50% in order to significantly reduce the hydrogen production cost. They are also seeking to overcome major technical issues, including corrosion and heat exchange, for the materials and components working at high temperatures, such as separation membranes. If these issues can be overcome, a source of cheap high-temperature heat (*i.e.* from nuclear or solar energy) will be required to make these proposed forms of hydrogen production attractive.

For the purpose of this study, only thermo-chemical water splitting is considered, given that the other processes being proposed are at a very early stage of their development. A number of thermally driven chemical cycles (more than 100) have been proposed for thermo-chemical water splitting. These include: sulphur-iodine (S-I), bromine-calcium (Br-Ca), and chlorine-copper (Cl-Cu) cycles. While these cycles are technically feasible from a chemical point of view, low cost and high efficiency processes that are commercially viable have yet to be developed. Sulphur-iodine appears to be the most promising cycle (Figure 2.7). It can achieve higher efficiencies and use chemicals that are easier to handle in comparison with those used in other cycles. This process is being researched and developed by the nuclear industry in France, Japan and the United States. Key issues are the capture of the thermally split H_2 to avoid recombination and side reactions, and corrosion problems associated with the materials involved in the cycle. The predicted efficiency is about 43% (LHV) at a temperature of 900 °C. Due to heat losses in the heat exchanger, the initial heat temperature source needs to be at least 950 °C.

The existing and currently commercially available nuclear reactors cannot deliver a temperature of 950 °C. However, a High-Temperature Test Reactor (HTTR) working at 950 °C is currently being trialled in Japan. Others are currently under design, including a Modular Helium Reactor (GT-MHR) proposed by General Atomics in the United States and a Pebble Bed Modular Reactor concept being developed in various countries. Both these new designs work at temperatures of 850-1000 °C. Most of the reactor concepts selected in the context of the Generation IV nuclear initiative also have the potential for hydrogen production (Bertel, 2004).

Figure 2.7

The sulphur-iodine thermo-chemical hydrogen production process



(850°C): $H_2SO_4 \rightarrow SO_2+H_2O+{}^1/_2O_2$

(120°C): $I_2+SO_2+2H_2O \rightarrow H_2SO_4+2HI$

(450°C): $2HI \rightarrow I_2+H_2$

SUM: $H_2O \rightarrow H_2+{}^1/_2O_2$

The investment costs for the hydrogen production process including the cost of the nuclear reactor, the cost of the intermediate loop (heat exchanger) and the cost of the S-I cycle are estimated at USD 710/kWt (Table 2.7). This is based on a Very High Temperature Reactor (VHTR) working at 950 °C. Given that the efficiency of the H_2 production is 45%, then the cost per kW of hydrogen production capacity is USD 1 580. Reactor decommissioning and nuclear waste treatment would add around USD 220/kW H_2, raising the total cost to USD 1 800/kW H_2. Assuming a 90% capacity factor, 12% annuity and 4% O&M cost, the projected cost of hydrogen would amount to USD 10/GJ H_2.

Table 2.7

Projected investment cost of H_2 production from nuclear heat

	(USD/kWth)
Very High Temperature Reactor (VHTR)	370
Intermediate loop	43
S-I hydrogen plant	297
Total H_2-VHTR H_2 plant	710

Source: Schulz, 2003.

Higher efficiencies can be achieved if the S-I cycle is operated at higher temperatures. If an advanced heliostat/collector is used to produce heat, the operating temperature would be some 1 100 °C and the efficiency could reach 56%. However, because of the smaller size, the cost of a solar S-I cycle using an advanced heliostat/collector would be four times higher per unit of capacity than the cost for the plant using nuclear heat. The cost of the whole solar S-I cycle system would be in the range of USD 1 360/kW. Assuming a capacity factor of 33%, 1.3% annual O&M cost and a 12% annuity, the projected production cost of hydrogen from solar energy would be around USD 20/GJ. This cost is considerably lower than that of a solar PV-based system, but it is twice the cost of hydrogen from coal and natural gas with CO_2 capture, and from the nuclear cycle. The higher costs are mainly attributable to the low capacity factor and the smaller size of the solar plant. The current state of development of thermo-chemical technologies to produce hydrogen suggests that commercially viable plants can be expected from 2030 onwards.

Hydrogen from biomass

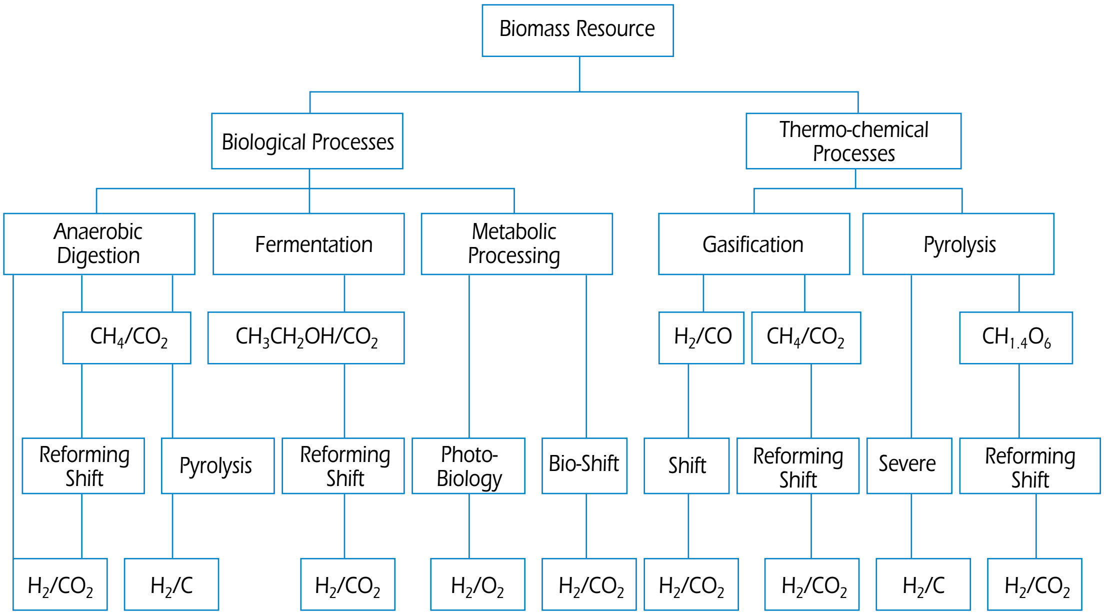
Biomass can be converted into hydrogen through a number of biological and thermo-chemical processes (Figure 2.9). Biological processes are generally much slower and more costly than thermo-chemical processes. While biological processes may play a role in the decentralised production of hydrogen, centralised production will generally be based on thermo-chemical processes, *i.e.* gasification and pyrolysis. Most of the research attention is focused on gasification, given that pyrolysis results in a wide range of intermediate products that require extensive processing. The gasification process is similar to that used for producing hydrogen from coal, but the scale of operation will probably be smaller, as large-scale units would need a large biomass supply, which increases the transport costs considerably. As a rule of thumb, if the process is half as big, the capital cost per unit of capacity is twice as high. The cost of primary biomass varies widely, but typically the cost of energy crops will be in the range of USD 2-5/GJ, or at least twice that of coal. Given the higher capital and feedstock costs, the centralised production of hydrogen from biomass using gasification will not be competitive with coal. However, niche technologies may be competitive in certain circumstances (*e.g.* using biomass residues or co-gasification with coal).

The gasification process can use a variety of biomass resources, such as agricultural residues and wastes, or specifically grown energy crops. The technologies for gasifying biomass in IGCC plants for power generation have been the subject of intensive R&D efforts over the last two decades. A certain number of demonstration units are in operation, but no concept has so far reached the technical maturity required for hydrogen production. Improved process economics and biomass logistics are needed if this option is to become attractive.

The production of hydrogen from biomass is in potential competition with biofuels production (bioethanol and biodiesel) for biomass supplies. Hydrogen and biofuels have the same advantage of being CO_2-neutral. However, biofuels have the dual advantage of being at a more advanced stage of development and of being easier to introduce into the existing transportation infrastructure and market. The use of biomass for producing hydrogen instead of liquid biofuels could, however, be very attractive if it is combined with CCS, because in this case the process would result in negative emissions.

Figure 2.8

Overview of hydrogen production routes from biomass



Source: Larsen *et al.*, 2004.

Other hydrogen supply options

Photo-electrolysis

Photovoltaic (PV) cells for electricity production coupled to electrolysers are commercially available. These systems offer some flexibility, as the output can be electricity from the photovoltaic cells or hydrogen from the electrolyser. However, their cost is high because of the high cost of the PV panels. Direct photo-electrolysis is an advanced alternative to PV-electrolysis. In photo-electrochemical (PEC) processes hydrogen can be produced in one step – the splitting of water by illuminating a water-immersed semiconductor with sunlight. In the photochemical cells, the semiconductor surface serves two functions, to absorb solar energy and to act as an electrode. The semi-conductor electrodes convert light energy into chemical energy. Such a system offers potentially lower capital costs than PV-electrolysis and its efficiency is 30% higher.

Four major PEC concepts are being actively studied, including: two-photon tandem systems, monolithic multi-junction systems, dual-bed redox systems and one-pot/two-step systems. While the first two concepts employ water-immersed thin-film-on-glass techniques, the latter two concepts are based on photosensitive powder catalysts suspended in water. To reach technical and commercial maturity, PEC technologies need advances in materials science and engineering. There is currently no commercially available photo-electrode material that is considered "ideal" in terms of conversion efficiency and stability, and new materials have to be synthesised and engineered if this is to be overcome. Research is also needed on doping for band-gap shifting, surface chemistry modification and systems integration. Test-scale PEC devices have been developed in recent years with solar-to-hydrogen conversion efficiencies of up to 16% (IEA HIA, 2005a). Although, far from being commercialised, these technologies could one day have a major impact on the prospects for hydrogen production.

Photo-biological production

Hydrogen can be derived from organic matter and water using micro-algal photo-synthesis. The process is based on two steps; the first is photosynthesis ($2\ H_2O \rightarrow 4\ H^+ + 4\ e^- + O_2$) and is followed by hydrogen production ($4\ H^+ + 4\ e^- \rightarrow 2\ H_2$) in green algae and cyanobacteria (Figure 2.9). Micro-algal hydrogen metabolism has to be genetically engineered in order to achieve significant production of hydrogen and the feasibility of the scheme depicted in Figure 2.9 is a matter of discussion. However, hydrocarbons could first be produced from sunlight and then converted into hydrogen using an anaerobic process. Significant research is needed to understand the natural processes and genetic engineering of H_2 production in large bio-reactors (particularly on genetically engineered algae for the efficient photosynthetic production of hydrocarbons), but possible breakthroughs would pave the way to a long-term solution to sustainable hydrogen production. An alternative approach consists of reproducing a two-step reaction using artificial photosynthesis. Laboratory-scale projects have demonstrated the ability of these processes to produce hydrogen, but the R&D into these processes is still in its infancy and production costs remain uncertain.

Figure 2.9

The principle of photo-biological hydrogen production

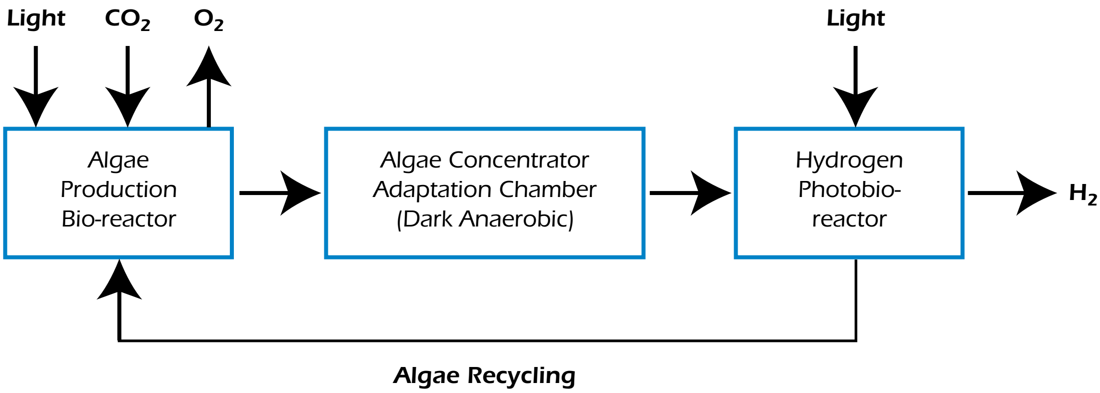


Table 2.8 provides an estimate of the investment cost and energy needs to produce hydrogen from kitchen waste and similar types of biomass feedstock. However, the process needs substantial amounts of electricity, and the efficiency of the biomass conversion is only 33%. In addition, the capacity factor will be limited to less than 50% by the fact that the bacteria need sunlight. Given these points, further substantial efficiency improvements and R&D effort will be needed if this process is to become attractive for producing hydrogen.

Photo-biological hydrogen production and PV systems combined with electrolysis have been considered in the model analysis contained in the second part of this study. PEC cells have not been explicitly considered, as the feasibility of the technology is not yet proven and it seems unlikely that the technology will be commercialised in the next three decades. However, further development of this technology should be supported by public RD&D, given its potential for low-cost hydrogen production from a widely available solar energy source.

Table 2.8

Investment and energy needs for photo-biological production

	Investment (USD/GJ H_2)	Energy (GJel/GJ H_2)	Feedstock energy (GJ/GJ H_2)
			3.03
Extruder	29	0.10	
Bioreactors, pumps etc.	36	0.16	
Sun collector	22	0.00	
Equipment H_2 recovery thermo-bioreactor	11	0.04	
Equipment H_2 recovery photo-bioreactor	5	0.05	
Purification H_2	0	0.00	
Total	104	0.36	3.03

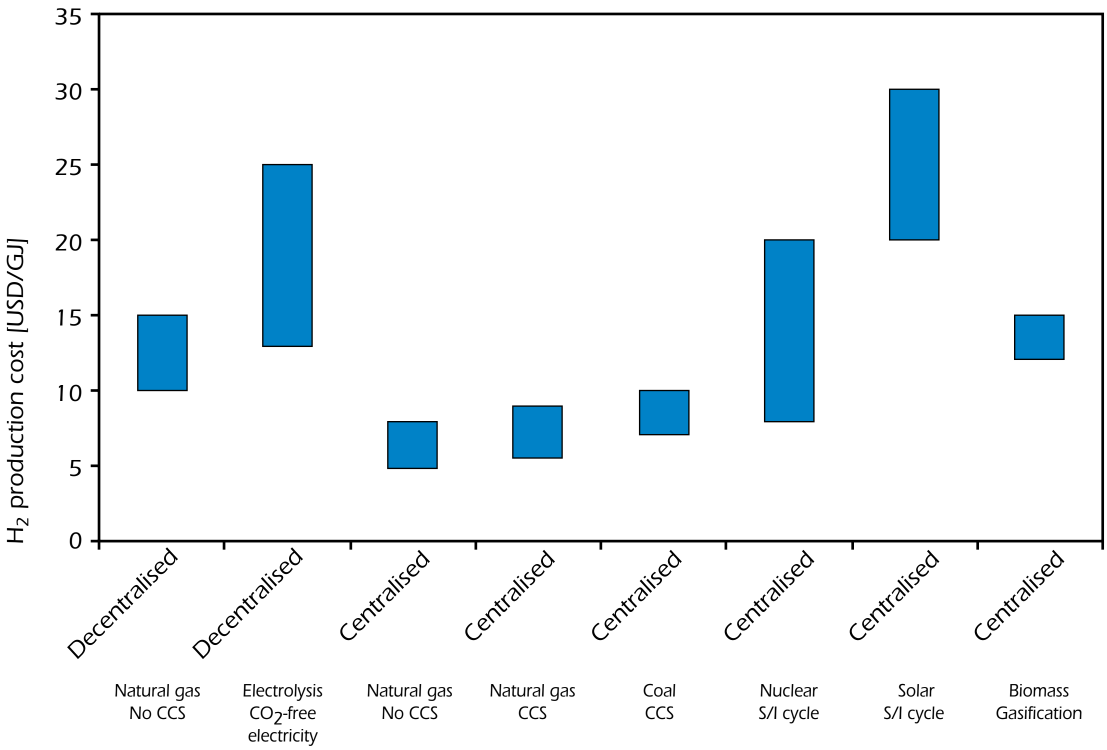
Source: Claassen *et al.*, 2000.

Summary of hydrogen production cost

Figure 2.10 provides a summary of projected hydrogen production costs from various sources and technologies. Currently the production cost of hydrogen at a decentralised level is more than USD 50/GJ H_2. In the mid to long term, various centralised production options promise hydrogen at less than USD 10-15/GJ H_2. While sensitive to electricity prices and natural gas prices, the cost of decentralised hydrogen production from electrolysis may be reduced to below USD 20/GJ H_2 by 2030 and that of natural gas reforming to below USD 15/GJ H_2. The projected cost of hydrogen from coal gasification with CO_2 capture could be even lower, at a level below USD 10/GJ H_2. The costs for high temperature water splitting could range from USD 10 /GJ H_2 to USD 20/GJ H_2 in the long term using nuclear and solar heat respectively. Higher costs are projected for other advanced technologies. Figure 2.10 shows somewhat wider ranges, because it reflects favourable estimates that do not apply to all regions, and a number of uncertainties regarding future prices of primary energy (natural gas, electricity), regional differences, costs of developmental technologies (*e.g.* nuclear and solar plants, S-I cycles, CO_2 capture and storage, advanced electrolysers), different assumptions for the discount rate, size of plants and economy of scale. For example, decentralised hydrogen production by electrolysis at less than USD 15/GJ using CO_2-free electricity seems to be realistic only if off-peak electricity is used and assuming that CO_2 capture and storage technologies will be available at low-cost. Similarly, "nuclear" hydrogen at less than USD 10/GJ will be available only under favourable assumptions on the cost of nuclear heat. The production cost of hydrogen from biomass gasification reflects the cost of the process, not the large uncertainty regarding the cost of making available the primary feedstock.

Figure 2.10

Hydrogen production cost projection



Key point: *Considerable uncertainties but prospects to make available hydrogen at competitive cost in the mid to long term*

Hydrogen transportation and distribution

Transportation of gaseous hydrogen by pipeline

Pipelines have been used to transport hydrogen for more than 50 years. Several thousands of kilometres of hydrogen pipelines are currently in place. For example, Air Liquide operates an 879 km network in Belgium, France, and the Netherlands. Air Products and Chemicals Inc. has two pipelines in the United States (Texas and Louisiana), with a total length of about 175 km. They carry some 190 000 kg of H_2 per day to refineries and chemical plants. Praxair Inc. operates pipelines in Texas and Indiana which total 275 km and deliver about 200 000 kg H_2 per day. Existing hydrogen pipelines are about 25-30 cm in diameter and usually operate at a pressure of 10-20 bar, but pressures up to 100 bar can also be used. Figure 2.11 shows the investment costs as a function of pipe diameter for hydrogen and natural gas pipelines. The investment cost for hydrogen pipelines of a given diameter is about twice that of natural gas pipelines. As hydrogen's energy density by volume is about a quarter that of natural gas, a larger pipe diameter or higher pressure is needed to supply the same amount of energy. For a pipeline with the same energy capacity, the cost for a hydrogen pipeline is therefore about six times higher than for natural gas.

Hydrogen pipelines need to be made of non-porous materials, such as stainless steel. This means hydrogen cannot be transported in most existing natural gas pipelines, because they are made of materials that are too porous for hydrogen. For example, plastic materials, often polyethylene, are commonly used for natural gas distribution and services (Thompson, 2003). Small hydrogen molecules would permeate these materials resulting in gas losses and making the pipeline materials brittle. The implication is that the introduction of hydrogen would require new pipelines for the transportation and distribution network. This represents a potentially huge investment cost.

An idea of how large this level of investment might be can be gauged by assuming the hydrogen pipeline network becomes as large as the natural gas network. The United States natural gas pipeline distribution network includes 1.74 million km of distribution pipelines and 1.05 million km of services pipelines, serving 55 million customers. The average replacement cost of the main pipelines would be USD 0.1 million/km, the average cost of service replacement would be USD 950 per service with 55 million services (Thompson, 2003). That puts the total investment for the gas distribution system in the United States at some USD 230 billion. In real terms (USD 2005 prices), the amount would be about USD 310 billion. This system currently supplies about 14.4 EJ of natural gas per year. So the investment cost is about USD 22/GJ of annual natural gas capacity. For hydrogen, the cost would double to around USD 620 billion[4]. The worldwide investment required to develop a hydrogen pipeline network might be in the order of USD 2.5 trillion, assuming the investment cost of USD 44/GJ of hydrogen capacity is applied to the global gas use by end-users of 55 EJ in 2003. These figures should be considered as order-of-magnitude estimates.

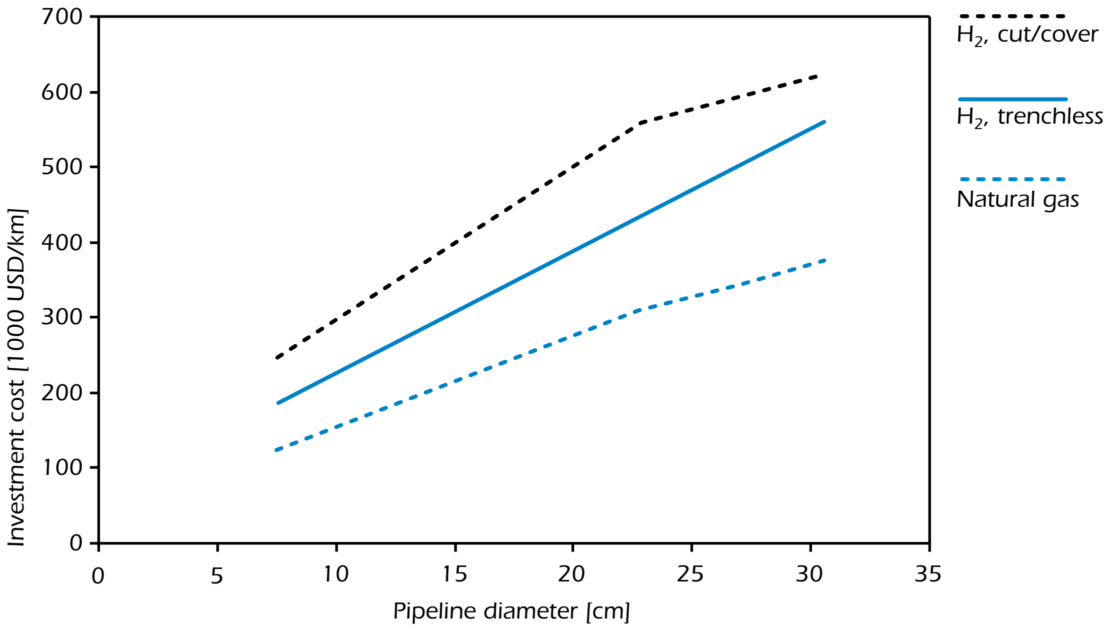
However, some ongoing research regarding the use of existing natural gas pipelines for hydrogen transportation suggests that certain parts of the natural gas system could be used for hydrogen transportation. If this is the case, then the pipeline investment cost could decrease substantially. In any event, a hydrogen system will probably be developed for the transportation sector first and then extended to other end-uses. If the production of hydrogen is centralised at large plants, then the cost of a worldwide pipeline system for the transport sector alone would be in the range of USD 0.1 to 1 trillion, spread over some decades. The wide range of this estimate reflects different assumptions regarding refuelling station size and density. How much of this investment would truly be an incremental cost due to the development of the hydrogen economy is a matter for discussion.

The energy required to move hydrogen through a pipeline is on average around 4.6 times higher per unit of energy than for natural gas. This means moving hydrogen over a distance of 1 200 km would imply a 10% (LHV) energy loss; the same energy would move natural gas 5 000 km (Eliasson and Bossel, 2002). As a consequence, the transportation of hydrogen through pipelines over long distances is not likely to be economically feasible. Based on the estimates in this section, the ETP model assumes that the transportation cost to deliver gaseous hydrogen to refuelling stations is USD 1/GJ. The cost of compressing the hydrogen to the refuelling pressure is included in the refuelling station. The trunk pipeline pressure will be in the range of 50 to 100 bar. The cost of distribution pipelines for hydrogen to the residential and commercial sectors is projected to decline from USD 100/GJ to USD 40/GJ of annual capacity.

4. This figure excludes any allowance for interstate pipelines and other large pipelines, which amount to another 3.4 million km in the United States. However, given the high cost and the considerable energy requirements for hydrogen pipeline transportation, the demand for long-range transportation is probably limited.

Figure 2.11

The cost of hydrogen and natural gas pipelines



Source: Mintz, 2003.

Key point: *Hydrogen pipelines are twice as expensive per unit of volume as natural gas pipelines. Significant economies of scale exist.*

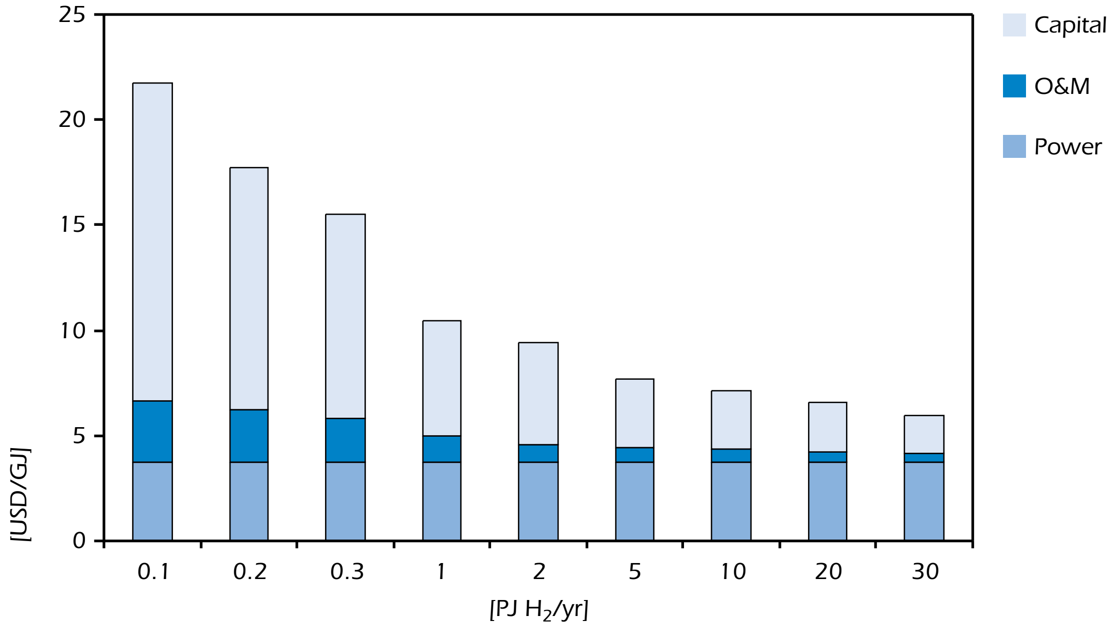
Transportation of liquid hydrogen by truck or ship

The liquefaction of hydrogen is potentially a very expensive process. In theory, a minimum of 14.3 MJ/kg H_2 are needed to liquefy hydrogen at -253°C. However, today's best large-scale plants require 36 MJel/kg H_2 (Syed *et al.*, 1998). This corresponds to 31% of the energy content of the liquid hydrogen. Research has suggested that a reduction of the energy needed to 25.2 MJel/kg H_2 is feasible, or around 21% of the energy content of the liquid hydrogen (Bossel *et al.*, 2003). Assuming that the electricity used was produced at 50% efficiency (the average for existing gas-fired power plants in OECD countries), even this improved liquefaction process would require primary energy inputs equal to 42% of the energy content of the liquid hydrogen. For very large systems (30 PJ/yr), a liquefaction cost of about USD 7/GJ has been estimated (Figure 2.12), 75% of which is due to the cost of electricity. The liquefaction cost is estimated to triple for the typical size of a refuelling station system.

In the ETP model, the liquefaction investment cost is assumed to decline from USD 150/GJ of annual capacity in 2005 to USD 50/GJ in 2030, and is stable afterwards (with a maximum plant size of 1 PJ per year, in order to account for scale limitations due to increasing distribution costs). The electricity use for liquefaction declines from 0.34 GJ/GJ of H_2 in 2005 to 0.30 GJ/GJ of H_2 in 2050. Although highly dependent on volume and distance, the cost of distributing one tonne of liquid hydrogen by truck to a refuelling station is assumed to be about USD 2.5/GJ. This is based on experience in the liquid nitrogen industry (Doty, 2004). In this study, it has been assumed to decline over time to USD 0.5/GJ in 2030 for airplane refuelling and to USD 2/GJ for cars.

Figure 2.12

Hydrogen liquefaction costs



Source : Syed *et al.*, 1998.
Note: The calculations assume a 12% annuity and USD 0.04/kWh for electricity.

Key point: Liquefaction costs are high, but there are important economies of scale

Transportation of liquid hydrogen by ship over long distances is also very expensive due to the very low temperature (90 degrees lower than for LNG) and the low energy density (40% of the LNG energy density of 22.5 GJ/m3) of liquid hydrogen. Fast ships are required in order to reduce the boil-off losses that amount to 0.2-0.4% of the liquid hydrogen per day. Although these losses can be recovered and used to fuel the ship (Abe *et al.*, 1998), the shipment cost will still be considerably more than for LNG. For the sake of this study, it is set at USD 2/GJ of H_2 for shipments of a few thousand kilometres.

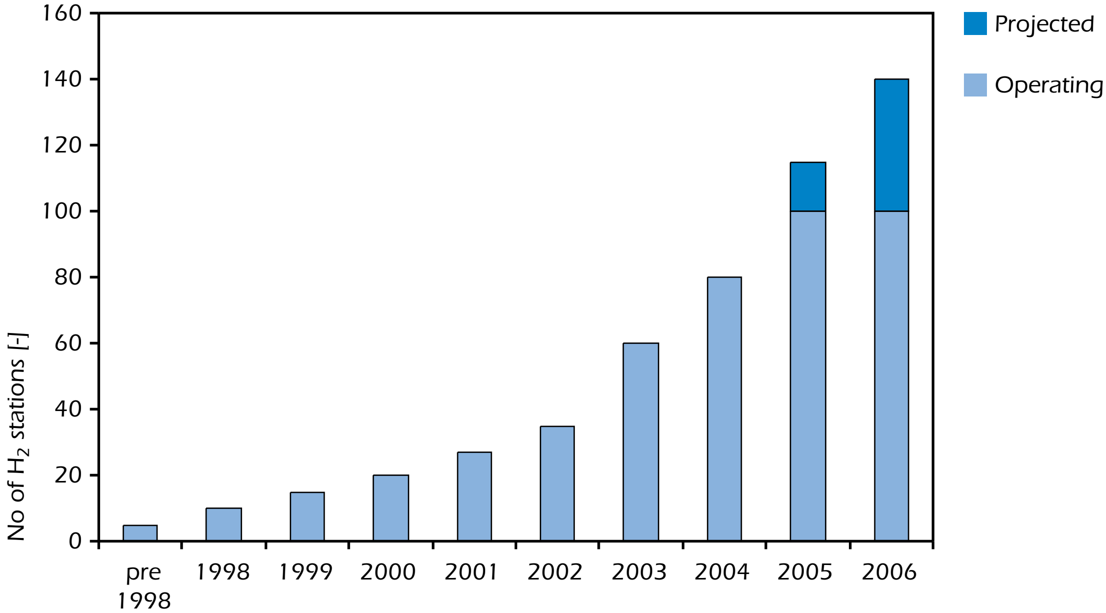
Hydrogen refuelling stations

Hydrogen refuelling stations represent an important component and a significant cost in the hydrogen chain for transport applications (IEA, 2003). However, the ultimate cost is uncertain, because only limited operational experience is available. About 100 hydrogen refuelling stations have been built to date (Figure 2.13).[5] These stations deliver either gaseous hydrogen at 350 bar or liquid hydrogen. They either produce their hydrogen on-site from electrolysis or steam reforming, or receive it from centralised plants. Gaseous hydrogen stations represented some 90% of the stations built in 2004-2005, while liquid hydrogen stations often have compressed hydrogen dispensers. This development, and the trend towards gaseous hydrogen stations, is driven by the fact that most fuel cell cars and buses run on gaseous hydrogen.

5. A list of over 60 existing hydrogen refuelling stations is provided in Annex 4.

Figure 2.13

Worldwide hydrogen refuelling stations



Source: Baker, 2005.

The basic assumptions for refuelling stations in this study are detailed in Tables 2.9, 2.10 and 2.11. Tables 2.9 and 2.10 show the cost of refuelling stations with on-site production and pipeline delivery that deliver gaseous hydrogen at 350 or 700 bar (the investment cost for decentralised production is indicated separately). Three refuelling station sizes are considered: 50, 500 and 1300 kg H_2 per day. As refuelling a fuel cell vehicle requires 4-5 kg H_2, this equals around 10, 100 or 300 vehicles per day. Three types of refuelling stations have been considered, 35 MPa (350 bar) multi-banking, 35 MPa booster concept and 70 MPa booster concept. The multi-banking system has three hydrogen reservoirs at different pressure, which are used in sequence from low to high pressure to fill a vehicle tank. This results in a more efficient use of the refuelling system. The booster concept assumes a storage reservoir operating at 300 bar and further pressurisation (to 400 or 800 bar) at the moment of refuelling.

Large refuelling stations operating at 700 bar experience significant economies of scale. The investment cost for the smallest station would be USD 272/GJ of H_2 capacity, while the largest station (300 vehicles a day) would require an investment cost of just USD 36/GJ of H_2 (Table 2.10). In general, small-scale refuelling stations have investment needs at least three times higher per unit of annual capacity. Especially for high pressure delivery (700 bar), the largest single investment required for refuelling stations using the booster concept is the cost of the compressor. Cost reductions for high-pressure compressors will be essential if this option is to become more competitive. The compressor cost of a refuelling station that produces its hydrogen on-site is higher than for stations receiving hydrogen by pipeline, because pipeline delivery takes place at elevated pressure, thereby reducing the size of the on-site compressor that is needed (Table 2.10).

The investment cost is also high for refuelling stations that are supplied with liquid hydrogen delivered by trucks (Table 2.11). The costs for the largest stations (1 300 kg H_2/d) translate into USD 5-6/GJ H_2 delivered. This does not account for the cost of delivering the liquid hydrogen, which adds significantly to the final cost. It is unlikely that this distribution option will take off on a large

Table 2.9

Investment costs for hydrogen refuelling stations by size

		35 MPa, multibanking			35 MPa, booster concept			70 MPa, booster concept		
Daily sale	**(kg H_2/day)**	**50**	**500**	**1 300**	**50**	**500**	**1 300**	**50**	**500**	**1 300**
Compressor	(USD 1 000)	39	195	458	255	510	764	371	926	1 112
Storage	(USD 1 000)	30	181	469	25	125	328	25	125	328
Refuelling system	(USD 1 000)	57	114	229	57	114	229	82	164	328
Installation cost	(USD 1 000)	31	98	139	85	187	255	120	243	265
Total	(USD 1 000)	157	588	1 295	421	936	1 576	597	1 457	2 032
Compressor cost in case of decentralised production	(USD 1 000)	0	0	0	285	694	1 139	400	1 139	1 356
Add on cost for distributed generation										
Steam reforming	(USD 1 000)	689	2 678	3 003	689	2 678	3 003	689	2 678	3 003
Electrolysis	(USD 1 000)	337	2 340	6 057	337	2 340	6 057	337	2 340	6 057

Source: DWV, 2003.
Note: Assumes hydrogen supplied at pipeline pressure (70 bar).

Table 2.10

Investment costs of hydrogen refuelling stations by station size (per unit of energy)

		35 MPa, multibanking			35 MPa, booster concept			70 MPa, booster concept		
Daily sale	**(kg H_2/day)**	**50**	**500**	**1 300**	**50**	**500**	**1 300**	**50**	**500**	**1 300**
Annual sale	(PJ H_2)	0.002	0.022	0.056	0.002	0.022	0.056	0.002	0.022	0.056
Compressor	(USD/GJ)	18	9	8	116	23	13	169	42	20
Storage	(USD/GJ)	14	8	8	11	6	6	11	6	6
Refuelling system	(USD/GJ)	26	5	4	26	5	4	37	7	6
Installation cost	(USD/GJ)	14	4	2	39	9	4	55	11	5
Total	(USD/GJ)	72	27	23	192	43	28	272	67	36
Compressor cost in case of decentralised production	(USD/GJ)	0	0	0	130	32	20	183	52	24
Add on cost for distributed generation										
Steam reforming	(USD/GJ)	315	122	53	315	122	53	315	122	53
Electrolysis	(USD/GJ)	154	107	106	154	107	106	154	107	106

Source: DWV, 2003.
Note: Assumes hydrogen supplied at pipeline pressure.

scale, but it may be very important in the initial stages of the introduction of hydrogen into the market. The high cost of refuelling stations and the high initial cost of hydrogen for end-users due to the low level of demand and the low density of hydrogen infrastructure has the potential to be the classic "chicken-or-egg" problem. That is, little hydrogen supply infrastructure will be developed without significant hydrogen demand, but no hydrogen demand will occur without the existence of a large-scale hydrogen supply infrastructure that can deliver hydrogen at an attractive price. In order to achieve significant momentum in the transition phase, either a dedicated fleet of vehicles that operate in a small area (*e.g.* buses) or multi-fuel vehicles (*e.g.* hybrid vehicles that can use hydrogen or gasoline) will be required in an area to encourage infrastructure growth. This will then lead to a virtuous self-sustaining cycle where more infrastructure creates more hydrogen demand, and hence the need for more infrastructure.

Table 2.11

Investment costs for H_2 refuelling stations by station size for liquid hydrogen delivered by truck

Daily sale	(kg H_2/day)	50		500		1 300	
On-board gaseous storage pressure	(MPa)	35	70	35	70	35	70
Liquid hydrogen storage tank	(USD 1 000)	130	130	629	629	629	629
Liquid hydrogen high pressure pump	(USD 1 000)	101	129	203	256	406	512
Air heated high pressure vaporiser	(USD 1 000)	47	47	94	94	186	186
Gaseous hydrogen storage buffer	(USD 1 000)	13	124	26	247	53	494
Refuelling system	(USD 1 000)	57	82	114	164	229	328
Installation cost	(USD 1 000)	87	127	213	278	225	322
Total	(USD 1 000)	436	638	1 279	1 668	1 728	2 471

Source: DWV, 2003.

Table 2.12 contains estimates of the investment needs of refuelling stations in 2030 where hydrogen is produced on-site by natural gas reforming. These estimates suggest that not only is the overall cost of stations expected to fall, compared to the current costs presented in Table 2.10, but that the cost of the reformer will fall to about 50% of the total cost of the refuelling station. However, more data is needed from experience at actual commercial refuelling stations before the true cost of hydrogen refuelling stations will become clear.

Table 2.12

Projected investment costs for refuelling stations with on-site hydrogen production from steam reforming in 2030

	SMR/PSA (USD/GJ)	ATR/PSA (USD/GJ)	SMR/Membrane (USD/GJ)	ATR/Membrane (USD/GJ)
Reformer system	24.53	20.33	27.21	22.93
Hydrogen compressor	4.13	4.13	5.05	5.05
Hydrogen storage	8.65	8.65	8.65	8.65
Dispenser	4.11	4.11	4.11	4.11
Other cost	4.25	4.11	4.32	3.87
10% contingency	4.57	4.13	4.93	4.46
Total	50.23	45.45	54.27	49.07

Source: Myers, 2002.

Note: The calculations are for a 115 kg H_2/day station (25 cars/day or 0.005 PJ/yr). H_2 storage at the refuelling station at 475 bar, for on-board storage at 350 bar.

The available data suggest an investment cost for refuelling stations with pipeline connection ranging from around USD 160 000 to USD 2 000 000 for stations serving 10 to 300 cars per day respectively. The investment cost rises considerably for the same size stations with on-site hydrogen production, with the station cost rising to USD 340 000 and USD 6 500 000 per station. This translates into investment costs of USD 23/GJ to USD 272/GJ of annual H_2 capacity for stations connected to a pipeline and USD 160/GJ to USD 600/GJ of annual hydrogen capacity for stations with on-site production. An overview of the cost estimates is presented in Table 2.13.

In addition to the capital costs, the operating and energy costs need to be included to arrive at the total cost of the refuelling station per unit of hydrogen. The considerable electricity needed for hydrogen compression is shown in Figure 2.14. Pressurisation at 800 bar requires 0.14 GJ/GJ of H_2. If the electricity price is USD 0.04/kWh (a low estimate), the cost of pressurisation would be around USD 1.6/GJ H_2 and the total refuelling cost amounts to USD 5.6/GJ H_2, including 12% annuity, 4% O&M cost, and the energy. These costs refer to large-scale stations (300 cars/day) based on a mature technology (the booster concept). During a transition period, the cost will be considerably higher.

Table 2.13

Overview of investment cost estimates for refuelling stations

		(USD/GJ of capacity)
Pipeline delivery	50 kg H_2 (10 cars) per day	272
Pipeline delivery	500 kg H_2 (100 cars) per day	67
Pipeline delivery	1300 kg H_2 (300 cars) per day	36
On-site production	50 kg H_2 (10 cars) per day	486-770
On-site production	500 kg H_2 (100 cars) per day	229-241
On-site production	1300 kg H_2 (300 cars) per day	112-159
Liquid H_2 delivery	50 kg H_2 (10 cars) per day	291

Source: DWV, 2003.
Note: H_2 pressure at 700 bar. The investment costs for centralised H_2 production and pipeline distribution are not included.

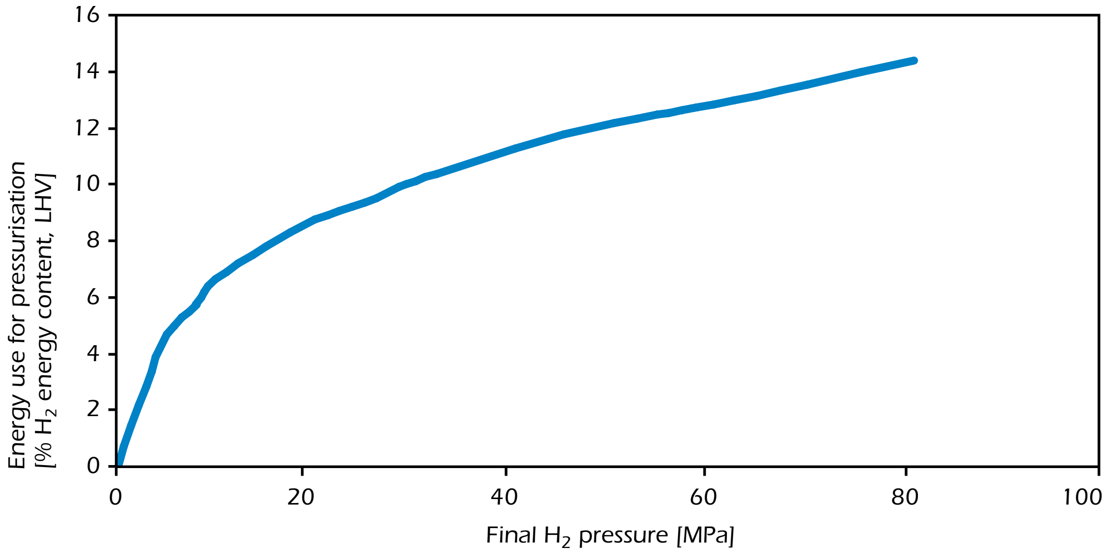
In this study, the investment cost for gaseous hydrogen refuelling stations served by pipelines is assumed to decline to USD 25/GJ of annual H_2 capacity over the next two decades (Table 2.10). The electricity needs are assumed to be 10% of the hydrogen energy content; based on the hydrogen being delivered by pipeline at a pressure of 75 bar, the need to compress to 800 bar for on-board storage at 700 bar and refuelling times of less than 3 minutes. The higher pressure is needed to overcome the temperature rise to more than 80 °C during the refilling process (DWV, 2003).

For liquid hydrogen delivered from a centralised production source, the distribution and refuelling cost must be accounted for as well. Based on the data for refuelling stations presented here, it is estimated that the investment cost for a liquid hydrogen refuelling station would amount to USD 100/GJ of annual capacity for a volume of 50 kg H_2/day (10 cars/day) and USD 20/GJ for a volume of 1 300 kg H_2/day (300 cars/day), based on the data in Table 2.11.

Table 2.14 shows the current relationship between the number of gasoline stations and the number of cars. Depending on the country, the gasoline station density ranges from 1 per 700 cars to 1 per 2 800 cars. This suggests an intensity of use (throughput) much higher than that which is

Figure 2.14

Energy needs for hydrogen pressurisation



Source : Bossel *et al.*, 2003.

Key point: *On-board high-pressure gas storage entails significant energy use for pressurisation*

Table 2.14

Number of gasoline stations and intensity of use for a number of countries

	Refuelling stations	Year	Cars (mln)	Cars/gasoline station
USA	170 700	2002	189	1 106
Japan	52 600	2002	52	996
Brazil	29 721	2002	21	704
Germany	15 970	2002	45	2 796
France	16 200	2000	29	1 800
UK	12 200	2000	28	2 335

generally assumed in hydrogen studies, where figures of 1 refuelling station per 300 to 750 cars are often assumed. At least part of this difference is explained by the fact that gasoline stations have multiple refuelling points, hence a higher potential throughput than for hydrogen stations, where studies assume only one or two refuelling points.

Given the present stock of 750 million cars and assuming one hydrogen refuelling station per 2 100 cars (one refuelling per week for 300 cars per day) at a cost of USD 1.3 million per station (pipeline delivery, multibanking refuelling system), then the investment cost for a complete conversion of the refuelling infrastructure to hydrogen would amount to around USD 0.46 trillion (excluding hydrogen production and delivery). The figure would be higher if hydrogen was produced on-site, as the investment for the hydrogen production plant would have to be included (electrolysis-based decentralised production would raise the cost of a refuelling station to USD 8 million, with potential for reductions to USD 2.5 million). However, the actual cost could vary considerably depending on the extent of the success of hydrogen in displacing conventional fuels, the rate of growth in car ownership, etc. This potential investment is also *not all incremental*, because part of these costs would be incurred for conventional stations in any event. For example, the cost of a gasoline refuelling station is around USD 0.2-0.5 million (depending on location and throughput and excluding restaurant, grocery store, land cost, etc.). Therefore, the *incremental* investment cost for a hydrogen refuelling infrastructure might be somewhere between USD 0.3 trillion for centralised hydrogen production and USD 0.7 trillion if production is decentralised. Previous studies (Table 2.15) have arrived at lower estimates of the investment required for refuelling stations because they assume only part of the vehicle fleet will use hydrogen.

Table 2.15

Different estimates of the investment required for the transition to hydrogen

Region	Refuelling stations	Centralised + distribution	Assumptions	Source
EU	EUR 6.3-23.6 bn	n.a.	5% of transportation fuels in 2020	(Mulder and Girard, 2005)
EU	EUR 120-180 bn	EUR 60-120 bn	60 000 refuelling stations by 2020	(Wurster, 2002)
EU	USD 4.6 bn		2 800 refuelling stations by 2020	Linde
EU	EUR 7-11 bn	EUR 0-3 bn	10 000 refuelling stations by 2020	(H_2 Steering Panel, 2004, based on HyNet)
USA	USD 80-420 bn	USD 0-390 bn	100 million FCVs	(Mintz, 2002)
California	USD 0.6-1.1 bn		2 500 stations, 183-1464 cars/day	(Directed Technologies)

Large-scale hydrogen storage

The cost of hydrogen storage depends on the technology used, storage capacity and the length of time the hydrogen is stored. Underground gas storage, where hydrogen is compressed and injected into underground storage aquifers or caverns, is the best method for storing large quantities of hydrogen over long periods of time. Three types of underground storage sites exist: depleted gas fields (and closed aquifers), salt mine caverns and hardrock mine caverns. The cost of these different caverns ranges from zero to more than USD 50/m^3.

The investment required for an underground storage facility, excluding the compressor, is in the range of USD 3.0-6.8/GJ of hydrogen storage capacity. This comprises the underground cavern or aquifer cost and the wells required for injecting the hydrogen. The cavern cost is in the range of zero to USD 3.8/GJ, assuming that the storage capacity at 200 bar and 100 °C is about 13.3 kg H_2/m^3. The cost of the wells for injecting the hydrogen is assumed to be USD 1 million per well for a storage capacity of 0.3 PJ (22.6 Mm^3) per well, or USD 3/GJ.

The energy needed to compress the hydrogen from 1 to 200 bar is around 7% of the H_2 energy content (Bossel *et al.*, 2003). However, it is assumed that 70% of this energy can be recovered when the gas re-expands to 1 bar. The electricity needs for storage therefore amount to 2.1% of the energy content, although Amos (1998) assumes a figure of 2.2 kWh/kg, which equals 6.6 MJel/GJ H_2 or 0.66% of the energy content. This study makes the conservative assumption that there will be one storage cycle a year, *i.e.* one filling and one extraction per year. It is also assumed that the storage site is filled in one month. The size of the compressor is determined by the filling time. Storing 0.3 PJ hydrogen in 1 month requires an 8 MW compressor (*i.e.* capable of 3.5 t/hr), as well as an expander for energy recovery.

The total investment cost (including cavern, compressor, expander, and auxiliary equipment) is assumed to be USD 15/GJ of annual capacity if there is one storage cycle per annum. However, this figure declines - due to the higher utilisation of the storage system - if there is more than one storage cycle per annum.

To calculate the total storage cost, O&M costs are set at 1.5% of the investment cost (USD 0.23/GJ per annum), the annuity at 12% of the investment cost and the price of electricity is assumed to be USD 0.04/kWh. Given these assumptions, the total storage cost equals some USD 2.7/GJ, 84% of which is capital cost.[6] More than one filling and extraction cycle per year would reduce the capital cost considerably.

Hydrogen as an electricity storage medium

Hydrogen has the potential to be a storage medium for electricity, as electricity can be used to produce hydrogen through electrolysis, while that same hydrogen could then produce electricity using the same device, i.e. *PEM fuel cells/electrolysers. Using hydrogen to store electricity is an option that might be attractive for intermittent renewable electricity sources. Tiax (2002) has compared various short-term electricity storage options, including the use of fuel cells and hydrogen. Although lead-acid batteries were the least-cost option, with a capital cost of only USD 210/kW, Tiax estimates in the long-run that the cost of a PEM system could be similar (USD 220/kW). However, the overall energy efficiency would only be 45% for the fuel cell and hydrogen storage, compared to 85% for the lead-acid battery. The production of hydrogen from electricity at times of low demand, followed by use in fuel cells during peak demand periods is not a viable competitor to battery storage. Regarding large-scale electricity storage, pumped hydro and underground pressurised air storage show better characteristics (higher efficiency and lower cost) than the fuel cell and hydrogen option.*

Hydrogen could also be produced from off-peak electricity and stored for later use, e.g. *as a transportation fuel, resulting in better use of existing electrical capacity. Depending on the choice of diurnal or seasonal production patterns, the hydrogen storage capacity required might vary significantly. The problem with the production of hydrogen from off-peak electricity is that the electrolyser capacity factor would be low (in the order of 20-30%). This would significantly increase the cost of the hydrogen produced, even if electrolysers decline in price substantially. For example, at USD 0.03/kWh, the electricity cost would amount to USD 11/GJ H_2 and the total production cost would be around USD 15-17/GJ H_2.*

On-board hydrogen storage

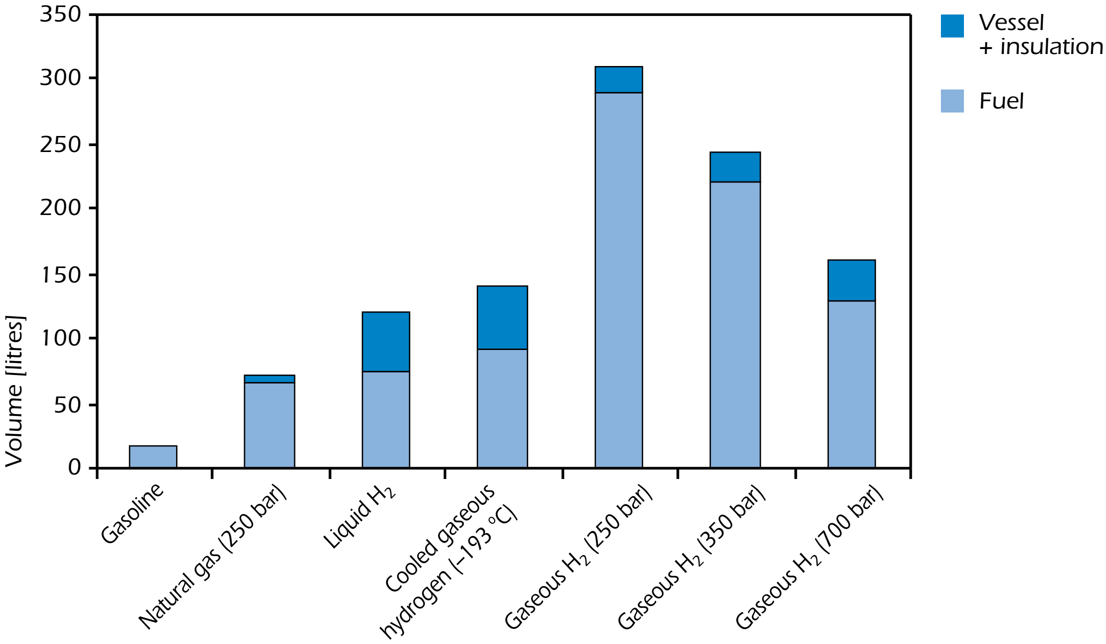
Although hydrogen storage is required for both stationary and automotive applications, the main R&D focus is directed at the question of on-board storage in either fuel cell vehicles or ICE/electric hybrid vehicles. Storing hydrogen, with its low energy content density, is a challenging pre-condition for introducing hydrogen as a transportation fuel.

6. The cost calculations do not include any allowance for hydrogen losses.

Hydrogen can be stored as a compressed gas in pressure vessels, as a liquid in cryogenic tanks and *adsorbed or absorbed* in solid materials. The mechanism is either physical or chemical bonding. The target is to store 5 kg of hydrogen (*i.e.* 460-580 km range for a mid-size FCV) in a small-volume vehicle's tank with at least 5-6 weight % of hydrogen (the so-called "gravimetric density"), a release temperature of 80-150°C, a rapid refuelling time, a low refueling energy, and a tank cost of around USD 150/kg. Figure 2.15 suggests that cryogenic liquid storage and gaseous storage at 700 bar require the least volume (*i.e.* 140 to 160 liters), but that they are seven to nine times more voluminous than gasoline fuel tanks with an equivalent fuel content. Solid metal hydrides promise three to four times higher hydrogen density than gaseous storage. Solid storage, however, is not commercially proven and may result in significant weight penalties, depending on the specific hydride used as a storage material.

Figure 2.15

Fuel tank volume by fuel type



Source: Berry and Lamont, 2003.
Note: The calculations are for 5 kg of hydrogen or energy equivalent for other vehicles.

Gaseous storage

Gaseous hydrogen can be stored in conventional steel vessels, or in high-pressure, low-weight carbon-fibre composite tanks operating at pressures of between 350 and 700 bar. The advantage of the carbon-fibre composite tank is the low weight. The tank consists of three layers: an inside polymer liner as a hydrogen permeation barrier, a carbon-fibre composite shell and an impact-resistant outer shell. These tanks have been certified and are commercially available at operating pressures of up to 350 bar. However, while storage at 350 bar would be sufficient for buses, passenger cars would require higher pressures in order to reduce the tank volume. Tanks for storage at 700 bar are in the demonstration stage (Shirosh, 2002), with Dynetek having delivered a number of units to Nissan for use in FCV test vehicles. In 2004/2005, one out of ten FCV test vehicles was equipped with a 700 bar storage system (Adamson, 2005).

High-pressure gas storage has a number of issues that need to be addressed before commercial production can begin. In addition to safety issues, the effects of the loading cycle on tank lifetime needs to be addressed. The high cost of gaseous storage tanks and the energy penalty in compression remain the main problems. The current cost of high-pressure composite tanks is very high, with a range of between USD 2 400/kg H_2 (Quantum Technology's estimate for a 165 litre hydrogen tank) and USD 3 300/kg H_2 (Motyka *et al.*, 2004). The US-DOE goal for 2015 is to lower the cost to USD 67/kg H_2, which implies that costs need to be reduced by a factor of at least 36.

In general, the carbon fibre cost represents 40-80% of the total tank cost, depending on whether low or high-performance fibres are used. High-performance carbon fibres have low "K" numbers, where the K stands for 1 000 filaments per fibre. A relatively cheap 24K fibre costs approximately USD 20/kg, while a high performance 12K fibre costs around USD 170/kg. These costs for carbon fibre translate into USD 650 per tank - or a material cost of USD 130 per kg of H_2 capacity - for a 165 litre tank using the 24K fibre.[8] The significant cost difference between the Quantum Technology estimate and the estimated materials cost suggests a significant assembly cost. There is therefore the potential for substantial cost reductions if mass production is introduced. Mass production could lower the tank cost to USD 500-600/kg H_2, but a cost reduction to meet the US-DOE target of USD 67/kg H_2 seems unlikely for this technology given that the production of carbon fibres is a mature process and their cost reduction potential is limited. In addition, the public's perception of high pressure gaseous hydrogen as an unsafe system should not be underestimated.

In the ETP model it is assumed that the cost of on-board storage tanks for gaseous hydrogen decline to USD 225/kg H_2 in the long term. Assuming 5 kg on-board storage and an 80 kW fuel cell system this translates into some USD 15/kW (vehicle power).

An alternative to gaseous hydrogen storage is offered by hollow glass micro-spheres. Filled by hydrogen permeation at a high pressure (350-700 bar) and temperature (300 °C), the micro-spheres are then cooled down to room temperature to retain the gas. They are then re-heated to 200-300 °C to release hydrogen to the fuel cell engine. A storage density of 5.4 wt% has been demonstrated (IEA HIA, 2005b). The main problems with micro-spheres are their low volumetric densities and the high filling pressure. The release of hydrogen at high temperatures is also of concern when using a PEM fuel cell engine working at 70-80°C. It is not yet clear if micro-spheres will become a viable storage option. The characteristics of composite tanks and glass micro-spheres are compared in Table 2.16.

Table 2.16

Gaseous H_2 storage: the merits of composite tanks and glass micro-spheres

Parameter	Composite tanks		Glass micro-spheres	
	Value	Comment	Value	Comment
Temperature, *T*	+	No heat exchanger needed	-	High *T* needed
Pressure, *p*	-	High *p* compressors needed	+	Low on-board *p* possible
Energy density	-	Only partially conformable	+	Up to 5 wt.% H_2, conformable
Robustness	+	Extensively tested	-	Breakable spheres
Safety	+	Existing codes & standards	+	Can be inherently safe
Cost	-	Long-term USD 500-600/kg H_2	?	Needs to be determined

Source: IEA HIA, 2005b.

8. This is based on a 165 litre tank requiring 47 kg of carbon fibre composite with 68% carbon fibre weight (Carlson et al., 2004). While the 24K carbon-fibre is assumed to cost USD 20/kg, an additional USD 4/kg is needed for binder.

Liquid storage

Hydrogen can be stored in liquid form at cryogenic temperatures (-253°C). Liquid hydrogen has been demonstrated in commercial vehicles, particularly by BMW. Although the theoretical density is 70.8 kg/m^3 and the theoretical gravimetric density is 100%, target values are 20 wt. %. This depends on the tank weight, insulation materials, systems adopted to recover boil-off losses, etc. The US-DOE indicates that practical values that can be achieved in today's liquid hydrogen storage systems are around 5 wt.%. Using liquefied hydrogen has significant disadvantages, including that some 0.3-0.7 GJ of primary energy is needed to produce 1 GJ of liquefied hydrogen, that boil-off losses occur even in highly insulated cryogenic tanks and that the public's perception is that liquid H_2 is an unsafe and very "high-tech" system. The main advantage with liquid hydrogen is the high storage density that can be achieved at relatively low pressures. Liquid hydrogen storage could be attractive in the future for aircraft given it has the lowest weight penalty of current storage systems.

The use of borohydride ($NaBH_4$) solutions is an alternative option for the liquid storage of hydrogen. The hydrogen is released through a catalytic hydrolysis reaction: $NaBH_4(l) + 2H_2O(l) \rightarrow 4H_2(g) + NaBO_2(s)$, with a theoretical storage density of 10.9 wt%. The main advantage of the $NaBH_4$ solution is that it allows for the safe and controllable on-board release of hydrogen, while the main disadvantage is that $NaBO_2$ must be stored in order to be unloaded and regenerated back into $NaBH_4$. The current regeneration costs of USD 50/kg should be able to be reduced to less than USD 1/kg, in spite of unfavourable thermodynamics. However, $NaBH_4$ solutions might be attractive in high-value portable and stationary applications. Other organic liquids for hydrogen storage such as methylcyclohexane (C_7H_{13}) and toluene (C_7H_8) could offer storage densities up to 6.1 wt.% (43 kg H_2/m^3). However, they release hydrogen at high temperatures (300-400 °C) and their use requires further study on safety and toxicity issues. The relative merits of different liquid H_2 storage options are given in Table 2.17.

Table 2.17

The merits of H_2 storage in liquid form and in solutions (Liquid H_2, $NaBH_4$ solutions and organic liquids)

Parameter	LH_2		$NaBH_4$ Solutions		Organic liquids	
	Value	Comment	Value	Comment	Value	Comment
Temperature, *T*	-	30-40% energy losses, Boil-off	+		-	T_{dehyd} = 300-400°C
Pressure, *P*	+	Low *P*	+		+	
Energy density*	+	100, 20, 5 wt.% **	+	10.9 wt.% H_2	+	6.1 wt.% H_2
Safety	-	Public perception	?		-	Potential toxicity
Cost	-	Infrastructure	-	Regeneration costs Infrastructure	-	Regeneration costs Infrastructure

Source: IEA HIA, 2005b.
* Theoretical values.
** Theoretical, target and practical value.

Solid storage

Hydrogen storage in solid materials offers the potential for the safe and efficient storage of hydrogen for both stationary and mobile applications. Four main groups of suitable materials are considered: carbon and other high surface area (HSA) materials, H_2O-reactive chemical hydrides, thermo-chemical hydrides and rechargeable hydrides.[9] A list of the potential materials within each of these broad groups is given in Table 2.18.

9. An overview of the various material options is given in (IEA HIA, 2005b).

Table 2.18

Solid storage materials under consideration

Carbon & other HSA materials	Chemical hydrides (H_2O-reactive)
• Activated charcoals • Nanotubes • Graphite nanofibres • Metal Organic Frameworks, Zeolites, etc. • Clathrate hydrates	• Encapsulated NaH • LiH & MgH_2 slurries • CaH_2, $LiAlH_4$, etc.
Rechargeable hydrides	**Thermal-chemical hydrides**
• Alloys & intermetallics • Nanocrystalline • Complex	• Ammonia borozane • Aluminum hydride

Source: IEA HIA, 2005b.

Carbon-based and HSA materials

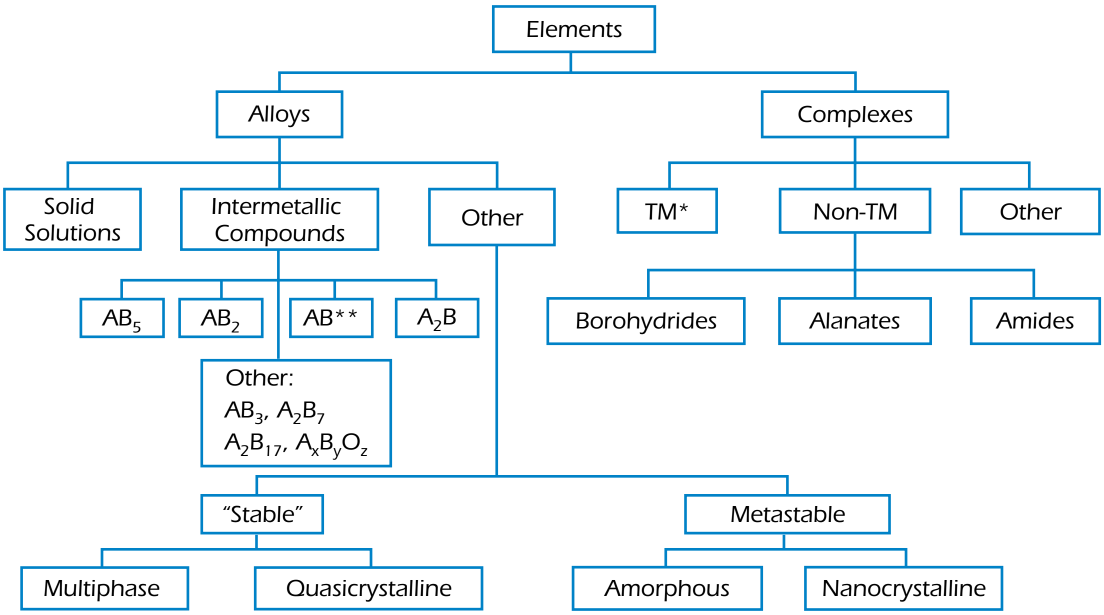
Nanotubes and graphite nanofibres have received a lot of attention over the past decade. The general consensus today is that the high storage capacities (30-60 wt%) reported a few years ago were the result of measurement errors. Pure hydrogen molecular physisorption up to several wt% has been demonstrated only at cryogenic temperatures. Nijkamp (Nijkamp *et al*., 2001) indicates a maximum of 2.13 wt.% hydrogen for their best activated carbon at 77 K and 1 bar. Pure atomic hydrogen chemisorption of up to 8 wt% has been reported, but the covalent-bound H is liberated only at impractically high temperatures above 400˚C (IEA HIA, 2005b). Currently, adsorption mechanisms are not fully understood and the technologies to economically produce suitable carbon materials still need to be developed. As a result, the storage of hydrogen in carbon-based materials is now considered a questionable option. Other hydrogen storage alloy (HSA) materials such as zeolites, metal organic frameworks (MOF, basically ZnO structures bridged with benzene rings) and clathrate hydrates might prove viable, but need more investigation. Engineered zeolites are porous HSA materials made from complex aluminosilicates. These materials are well known as molecular sieves for capturing gases. MOF have extremely high surface areas. Clathrate hydrates are H_2O-ice cage structures that may contain guest molecules such as CH_4. HSA materials have shown a storage capability of a few wt% at cryogenic temperatures. The question is whether they can be engineered to store significant amounts of hydrogen at near room temperature. MOF and clathrate hydrates are promising and are some of the new storage ideas that would benefit from further investigation.

Rechargeable hydrides

Rechargeable hydrides have been the subject of research for decades and their properties are well known (IEA HIA, 2005b). The metal hydride "family tree" is provided in Figure 2.16. *Elemental hydrides* are well understood, but they are too stable or unstable for use at practical temperatures (0-100 °C). *Alloys and intermetallic compounds* are well understood, although expensive, and work at temperatures less than 100 °C. Their low gravimetric density (< 2.5 wt%) makes them unsuitable for vehicles, but they could be used for stationary storage. *Nanocrystalline and Amorphous hydrides* show good kinetics, but unfavourable storage capacities and release temperatures. *Complex hydrides*, particularly borohydrides, alanates and amides could prove promising, but require further development. $NaAlH_4$, in particular, has good low-temperature kinetics and its reversibility may be improved by using a catalyst such as titanium. However, $NaAlH_4$ practical (reversible) storage is only around 4-5 wt% and the costs are rather high. As catalysed $Mg(AlH_4)$ is characterised by a poorly reversible hydrogen storage reaction and other alanates have high release temperatures, the main RD&D direction is to investigate catalyst concepts for other alanates. Borohydrides have a higher capacity potential than alanates, but they are too stable (they do not release the hydrogen easily) and less reversible. However, progress has been achieved in improving the performance of the $LiBH_4$ borohydride. The main RD&D goals for borohydrides are to develop improved catalysts, to reduce the temperature at which hydrogen is released and to lower costs. The key properties of some alanates and borohydrides are provided in Table 2.19.

Figure 2.16

The metal hydride family tree



(*) TM = transition metal complex hydrides.
(**) A_xB_y = Typical intermetallic compounds.
Source: IEA HIA, 2005b.

Table 2.19

The key properties of selected alanates and borohydrides

Alanates	Max. theoretical storage density, wt% [a]	H_2 release temperature, °C
$LiAlH_4$	10.6	190
$NaAlH_4$	7.5	100
$Mg(AlH_4)$	9.3	140
$Ca(AlH_4)$	7.8	>230
Borohydrides		
$LiBH_4$	18.5	300
$NaBH_4$	10.6	350
KBH_4	7.4	125
$Be(BH_4)_2$	20.8	125
$Mg(BH_4)_2$	14.9	320
$Ca(BH_4)_2$	11.6	260

[a] The currently achievable maximum storage wt.% level is often less than the theoretical values. For example, the maximum hydrogen storage in NaAlH4 is currently 5.6 wt.%.

Water-reactive chemical hydrides

Water-reactive chemical hydrides can be safely handled in a semi-liquid form, such as a mineral-oil slurry. The controlled injection of water into the slurry containing the chemical hydrides results in the release of hydrogen. This process has the advantage that releasing the hydrogen does not require any heat, while the theoretical maximum storage is around 5-8 wt%. It appears that, given the current state of research, MgH_2 is likely to offer the best combination of performance and cost. The key RD&D goal is to reduce the cost of the energy intensive process of converting the spent hydroxide back into a hydride.

Table 2.20

The storage density of water-reactive chemical hydrides

Hydrolysis Reaction	Max. theoretical storage density, wt%
$LiH + H_2O \Rightarrow H_2 + LiOH$	7.8
$NaH + H_2O \Rightarrow H_2 + NaOH$	4.8
$MgH_2 + 2H_2O \Rightarrow 2H_2 + Mg(OH)_2$	6.5
$CaH_2 + 2H_2O \Rightarrow 2H_2 + Ca(OH)_2$	5.2

Thermal chemical hydrides

Ammonia borane is a group of chemical hydrides that are potentially suitable for the storage of hydrogen in a solid state (IEA HIA 2005b). However, reactions are not reversible and off-board regeneration is required. Further research is required to investigate the viability of this option.

Table 2.21

The key characteristics of thermal-chemical hydrides

Decomposition reaction	Maximum theoretical storage density (wt%)	Decomposition temperature, (°C)
$NH_4BH_4 \Rightarrow NH_3BH_3 + H_2$	6.1	< 25
$NH_3BH_3 \Rightarrow NH2BH2 + H_2$	6.5	< 120
$NH_2BH_2 \Rightarrow NHBH + H_2$	6.9	> 120
$NHBH \Rightarrow BN + H_2$	7.3	> 500

Summary of the options for on-board storage

Existing on-board storage options for hydrogen FCVs do not meet all of the targets for performance and cost. Considerable R&D effort is still needed if these targets are to be met. At present, gaseous storage in carbon-fibre vessels at 350-700 bar and cryogenic liquid storage at -253°C are commercially available, but costly options. For buses, gaseous storage at 350 bar would be sufficient, but this pressure is too low for passenger cars. Currently projected costs of storage tanks are still too expensive (USD 600-800/kg H_2) and have short lifetime, while the high energy needs for compression and liquefaction add considerably to the final cost of hydrogen.

In comparison with gaseous and liquid options, solid storage has the potential to store the equivalent quantity of hydrogen at a low volume and pressure, and require fewer energy inputs. It is, however, in the very early stages of development and a number of process and materials issues need further investigation and improvement. Although, it is too early to identify the best option, the most developed materials for solid storage are metal hydrides. These hold the potential for storage at more than 8 wt%, or 90 kg/m_3 at 10-60 bars. However, a number of new materials such as complex hydrides are being investigated and these could prove to be more attractive in the long run.

The key challenge for on-board hydrogen storage is to find innovative solutions that can lower costs and improve the energy efficiency of on-board storage systems for hydrogen-use cars. Without further breakthroughs, gaseous storage at 700 bar seems the technology of choice for passenger cars in the near term. However, such a system is unlikely to be able to meet the DOE cost target of USD 67/kg H_2. Given that the choice of on-board storage system may influence the choices for the least-cost hydrogen infrastructure - including for production, distribution and refuelling - the identification of a suitable and cost-effective storage technology is an urgent issue. Table 2.22 presents a summary of the characteristics of some hydrogen storage options.

Table 2.22

Targets and performance for on-board hydrogen storage

Desirable technical characteristics: Low volume/weight tank, high H_2 content (> 5-6 wt% H_2), low pressure, temperature suitable for fuel cell engines (80-150 °C), short refuelling time, low storage energy, prompt H_2 release and low costs (USD 150/kg) for storage of 5 kg H_2 for 500 km drive in a FCV.

Current performance

	Gaseous storage C-fibre vessels	Liquid storage cryo-tanks	Solid storage metal hydrides
Weight (wt % H_2)	4 (6)	4-5 (20)	8 ?
Volume (l)	240-160	120-130	60-80 ?
Pressure (bar)	350-700	1 bar,	10-60 bar ?
Temp. (°C)	room T	-253 C	?
Cost (USD/kg)	600-800	700-800	?
Storage energy (% LHV H_2)	22-30	60	Low ?
Status	Commercial	Commercial	Developmental
Pros	temperature and time	volume, pressure and time	volume, pressure, energy and H_2 purity
Cons	lifetime, volume, safety, cost and storage energy	lifetime, boil-off, safety, cost and storage energy	lifetime, weight, time, reversibility and cost
Alternative Options	Glass micro-spheres	$NaBH_4$, C_7H_{14}, C_7H_8	Nano-C, MOF HAS, alanates, borohydrides, thermal hydrides

Note: Storage energy for gaseous hydrogen is calculated starting from 1 bar and assuming 50% efficiency in electricity production. The storage energy will be lower if hydrogen is received under pressure via a pipeline.

Chapter 3.

FUEL CELLS AND OTHER HYDROGEN END-USE TECHNOLOGIES

HIGHLIGHTS

- Fuel cells are the technology of choice to maximise the potential benefits of hydrogen in terms of energy efficiency, improved energy-security and lower emissions.
- Proton exchange membrane fuel cells (PEMFCs) are suitable for both stationary and transport applications. However, their sensitivity to carbon monoxide and sulphur pollutants requires a pure hydrogen gas (*e.g.* hydrogen produced by electrolysis). Hydrogen from natural gas reforming or from residual industrial gases would need purification after production.
- At present, PEMFCs seem to be the best fuel cell technology for fuel cell vehicles (FCVs). PEM technology could also be used in electrolysers to produce hydrogen, resulting in potential synergies between FCVs and hydrogen production infrastructure. Direct Ethanol Fuel Cells (DEFCs) could also become an interesting option for transport, but they are still at a very early stage of development.
- The current stack cost of PEMFCs exceeds USD 2000/kW, but a reduction to less than USD 100/kW seems to be feasible. However, even this significant cost reduction would not be enough to produce FCVs that are competitive with conventional vehicles. To be competitive, PEMFCs need to reduce their costs to below USD 50/kW. This requires fundamental advances in the materials used in PEMFCs and higher fuel cell power densities.
- The RD&D for PEMFCs is focusing on high temperature membranes that are less prone to poisoning and enable on-board reforming. The uncertainty surrounding the hydrogen purity that will be needed for PEM technologies means that it would be premature to make choices for hydrogen infrastructure at this point.
- The efficiency of hydrogen FCVs is twice that of current internal combustion engine (ICE) cars on the highway and three times as high in urban traffic. However, FCVs are not ready for commercialisation. In addition to cost reductions in fuel cell stack, they need to improve their durability and reliability. Other components, including the electric drive and hydrogen storage system, also contribute to the FCV cost. Assuming a cost of the PEM fuel cell stack of USD 35/kW and USD 75/kW in 2030, the *incremental* cost of FCVs over an ICE vehicle would be USD 2 200 to USD 7 600 per vehicle, respectively. The global *incremental* cost for some 700 million FCVs that could be sold between now and 2050 would then be in the range of USD 1-2.3 trillion.
- Buses, delivery vans and forklifts are "niche" markets where fuel cell engines can be competitive with traditional gasoline and diesel internal combustion engines (ICEs) at a higher cost than for cars. It is estimated that to be competitive in buses, fuel cell stack costs need to fall to USD 200/kW, while they need to fall to USD 135/kw for delivery

vans and to USD 100/kW for forklifts. Buses could in principle be the largest and most promising market. The early foothold FCVs could carve in these markets would contribute to cost reductions through "technology learning" that could then benefit the competitiveness of PEMFCs in the passenger car market.

- Molten carbonate fuel cells (MCFCs) and solid oxide fuel cells (SOFCs) are the most promising candidates for use in stationary applications, but are not suitable for vehicles because of their high operating temperatures that result in long start-up time. They are less sensitive to pollutants than PEMFCs and their electric efficiency is higher. While current MCFCs are fuelled by natural gas, SOFCs can be fuelled by either hydrocarbons or pure hydrogen. Both MCFCs and SOFCs do not require external reformers because of the high operating temperature.
- Natural gas-based MCFCs and SOFCs appear to have similar prospects and share part of the market in the coming decades. However, hydrogen-fuelled SOFCs could be preferred for reducing CO_2 emissions because CO_2 capture in small, decentralised fuel cell plants is not likely to be feasible.
- Stationary fuel cells could fill a market gap between large-scale combined heat and power (CHP) units and small-scale boilers, thus extending the economic feasibility of distributed CHP to the level of buildings. However, it is not clear that they would be attractive for the decentralised generation of electricity alone, as their electrical efficiency is still lower than that of competing technologies for centralised generation. If used for CHP applications, fuel cells could achieve overall efficiencies of around 90%. Stationary fuel cells can bear higher costs than fuel cells for mobile applications due to their higher load factor and the higher cost of competing conventional technologies. Their cost is expected to decline by a factor of five to ten and to become competitive once mass production is introduced.
- Direct methanol fuel cells (DMFCs) use methanol rather than hydrogen as a fuel and are the best candidates for portable applications, given that PEMFCs face hydrogen storage problems and that the operating temperatures of MCFCs and SOFCs are too high for portable applications. However, their low efficiency makes them uneconomic for mobile and stationary uses.
- Portable DMFCs appear close to the point of commercialisation, while they are likely to be followed by stationary MCFC and SOFC systems for decentralised use. More RD&D is needed before mobile PEMFCs are ready for commercialisation, although they are urgently needed to meet environmental and energy-security objectives.

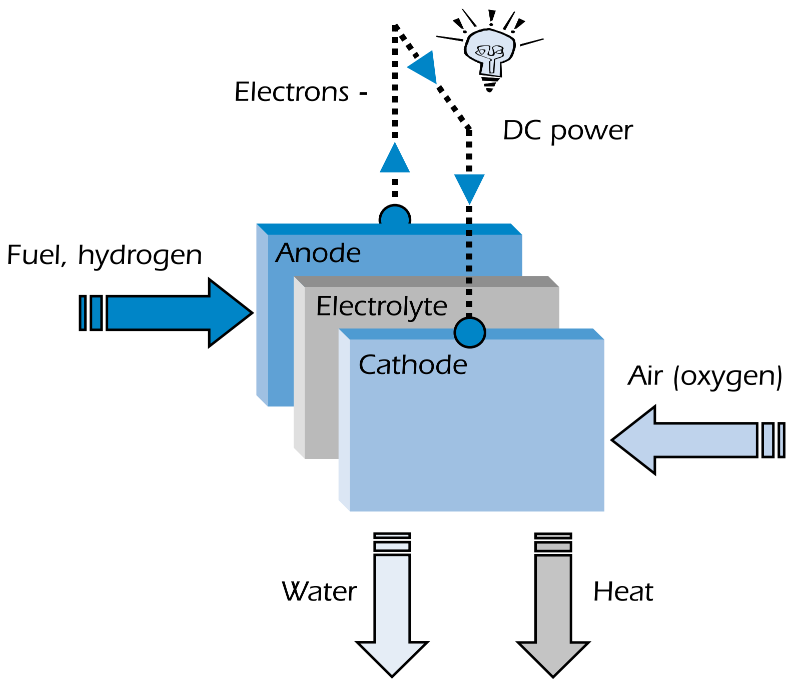
Hydrogen and fuel cells do not need to be used together. However, the use of hydrogen-fed fuel cells holds important synergies and maximises the potential benefits in terms of energy efficiency, energy-security and the emissions of CO_2 and other pollutants. As a consequence, fuel cells represent the technology of choice for using hydrogen as an energy carrier. They might be an attractive option in the the transport, residential, commercial, industrial and power generations sectors. Using hydrogen fuel cells in automotive applications represents one of the few options capable of replacing or complementing oil use, and reducing CO_2 emissions in the transport sector.

Overview of fuel cell types

Fuel cells use hydrogen (or a hydrogen-rich fuel) and oxygen to produce electricity through an electrochemical process. A fuel cell consists of two electrodes – a negative anode and a positive cathode – sandwiched around an electrolyte. In simple terms, they operate by feeding hydrogen to the anode and oxygen to the cathode. At this point, activated by a catalyst, 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.

Figure 3.1

The fuel cell concept



The production of fuel cells in 2003 amounted to 2 800 systems (Fontell, 2004), of which 800-900 were stationary fuel cell units with a capacity greater than 0.5 kW, 1 600-1 800 were portable fuel cell units and 200 were fuel cells for cars and buses. The total power of these fuel cell systems amounted to about 30 MW and sales were USD 338 million in 2003 (PWC, 2004). Some 2 700 stationary systems have been constructed and are in operation worldwide, of which 2 000 are small units of 0.5-10 kW and 700 are large units of 10 kW or more. In 2003 alone, 800 small stationary units and 50-60 large units were installed.

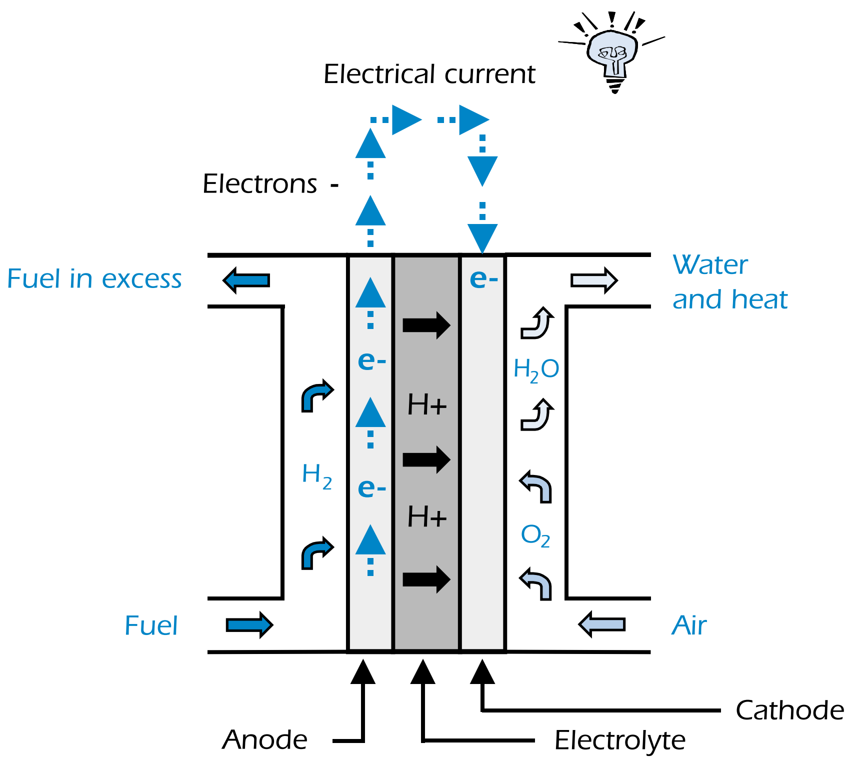
Proton exchange membrane fuel cells are the technology of choice for the transportation sector and also represent 70-80% of the current small-scale stationary fuel cell market. Solid oxide fuel cells (SOFCs) represent 15-20% of the stationary market at the moment, but their share is projected to increase gradually. Phosphoric acid fuel cells (PAFCs) dominated the large-scale stationary market until 2002, but molten carbonate fuel cells (MCFCs) are expected to take most of this market in the period 2005-2015, along with a gradually increasing share of SOFCs (Fontell, 2004).

Proton exchange membrane fuel cells

Proton exchange membrane fuel cells (PEMFCs) are particularly suited to powering passenger cars and buses due to their fast start-up time, favourable power density and power-to-weight ratio. Fuelled with pure hydrogen from storage tanks or on-board reformers, PEMFCs use a solid polymer as an electrolyte and porous carbon electrodes with a platinum catalyst. They operate at relatively low temperatures of around 80°C. This has the advantage of allowing fuel cells to start quickly, but it requires cooling of the cell in order to prevent overheating. The platinum catalyst is, however, costly and extremely sensitive to CO poisoning. New platinum/ruthenium catalysts seem to be more resistant to CO. The RD&D effort is also focusing on new high temperature membrane materials that will be less prone to poisoning and that would enable on-board reforming. In addition, high-temperature PEMs avoid the need for large cooling systems.

Figure 3.2

The proton exchange membrane fuel cell concept



Phosphoric acid fuel cells

Phosphoric acid fuel cells (PAFCs) use phosphoric acid as an electrolyte and porous carbon electrodes containing a platinum catalyst. They were the first fuel cells ever used commercially and over 200 units are currently in use. Primarily used in stationary power applications, they have also been used to power buses. PAFCs tolerate hydrogen impurities and can achieve overall efficiencies of around 85% when used for electricity and heat co-generation, and around 37-42% for electricity production alone. However, they are larger and heavier than other fuel cells with the equivalent power output. They are also expensive, at around USD 4 000-4 500/kW, because they require an expensive platinum catalyst. PAFCs currently play a role in niche applications and they should be considered as an established technology with limited potential for cost reductions below USD 4 500/kW. United Technologies Corporation, which sold over 250 PAFC installations of 200 kW, no longer produces PAFCs and has switched to the production of PEMFCs, which offer greater potential cost reductions over time (Blesl *et al.*, 2004).

Direct methanol fuel cells

Direct methanol fuel cells (DMFCs) were developed in the early 1990s and use methanol as a fuel. Methanol has a higher energy content per unit of volume than hydrogen and is easily transported. DMFCs appear to be a promising option for replacing batteries in portable applications such as cellular phones and computers. They currently account for 10 % of the global fuel cell RD&D effort (PWC, 2004) and their commercial introduction is underway. In DMFCs, liquid methanol is oxidized in the presence of water at the anode and generates CO_2, hydrogen ions and electrons. The hydrogen ions travel through the electrolyte, while the electrons travel through the external circuit producing electricity. At the cathode, the hydrogen ions react with oxygen from the air and the electrons from the external circuit to form water. The main drawbacks of DMFCs are their low efficiency and power density. The efficiency is currently limited to around 15-20%, because of methanol crossover from the anode to the cathode. This methanol is not only lost, but poisons the catalyst. Recent R&D progress has resulted in an increased power density and the efficiency may eventually reach 40% (FCTEC, 2003). The Los Alamos National Laboratory in the United States has developed a 50 W DMFC with 1 kW/l power density and 37% electrical efficiency (Dillon *et al.*, 2004). The use of DMFCs will probably be limited to portable applications where the advantages of methanol as a readily transportable fuel outweigh their low efficiency.

Direct ethanol fuel cells

The interest in developing direct ethanol fuel cells (DEFCs) has declined over the last couple of years, because the kinetics of ethanol oxidation is much more complicated than for methanol. The strong C-C bond results in high over-voltages and low conversion efficiency. The high over-voltages are also caused by the use of a Platinum (Pt) catalyst. The recent development of a non-Pt catalyst reduces the over-voltage problem, and preliminary indications suggest that an efficiency of around 42-45% might be achievable (Barbaro *et al.*, 2005). If these results are confirmed, the interest in DEFCs may increase significantly, because DEFCs might then be a candidate for use in FCVs.

Hydrogen membrane fuel cell

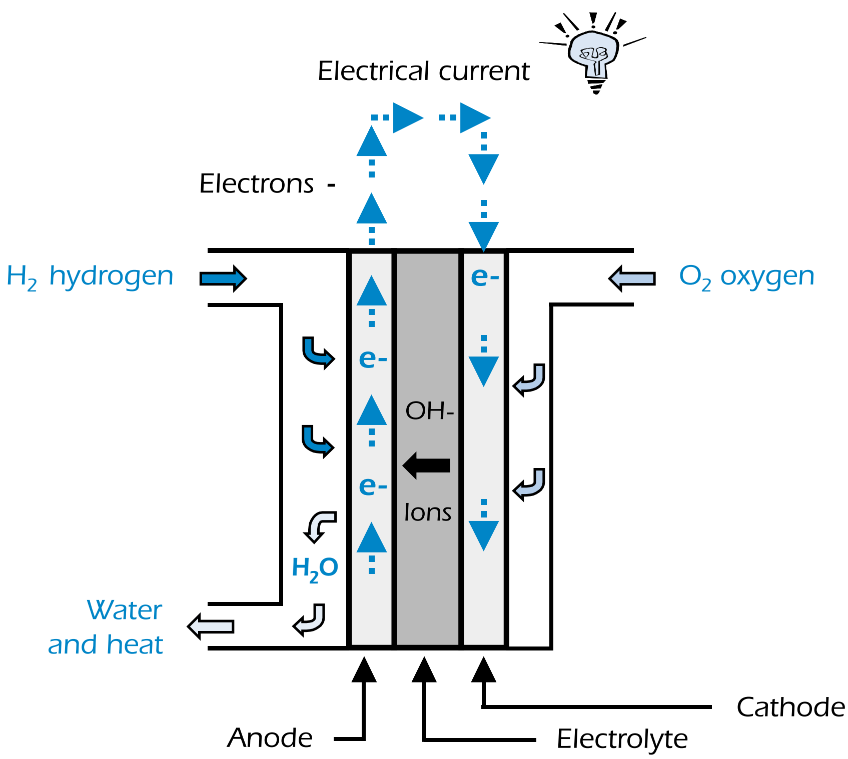
Hydrogen membrane fuel cells (HMFCs) operate at a temperature of around 500 °C and are a new concept that has been developed by Toyota (Kawai, 2004). They consist of a palladium (Pd) dense film combining a metal hydrogen membrane and an anode, and a perovskite $BaCeYO_3$ at the cathode. The thickness of the cell is only 1-1.5 mm, considerably less than the typical thickness of a PEMFC at 5 mm. The thinner electrolyte membrane provides higher proton conductivity and a power density of 0.78 kW/m^2. This is higher than for current Nafion membranes, but lower than new PEM membranes. Palladium replaces the platinum catalyst. Toyota hopes to use HMFCs in vehicles fuelled by hydrocarbons, alcohol or dimethyl ether, using on-board reforming. The high operating temperature of the HMFCs will prevent CO absorption by the catalyst, thus eliminating the need for a CO scrubber. The high operating temperature is also closer to the hydrocarbon reforming temperature and allows the use of smaller heat exchangers. HMFCs also take up less space than some other fuel cells; however, the high operating temperature implies longer start-up times.

Alkaline fuel cells

Alkaline fuel cells (AFCs) were the first fuel cell technology ever developed and were used in the United States' space programme. They use a potassium hydroxide solution as the electrolyte and a variety of non-precious metals as a catalyst at the anode and cathode. AFCs typically operate at between 100-250 °C, but recent versions operate at between 23-70 °C. AFCs are high-performance devices that achieve an efficiency of 60%, but they are vulnerable to poisoning by even small amounts of carbon dioxide. This makes it almost impossible to operate these fuel cells in a normal atmosphere (*e.g.* in cars), as they need pure oxygen. Their commercial use is therefore constrained by costly purification processes and their short lifetime of 8 000 hours, around one-fifth of the economic target of 40 000 hours for stationary systems.

Figure 3.3

The alkaline fuel cell concept



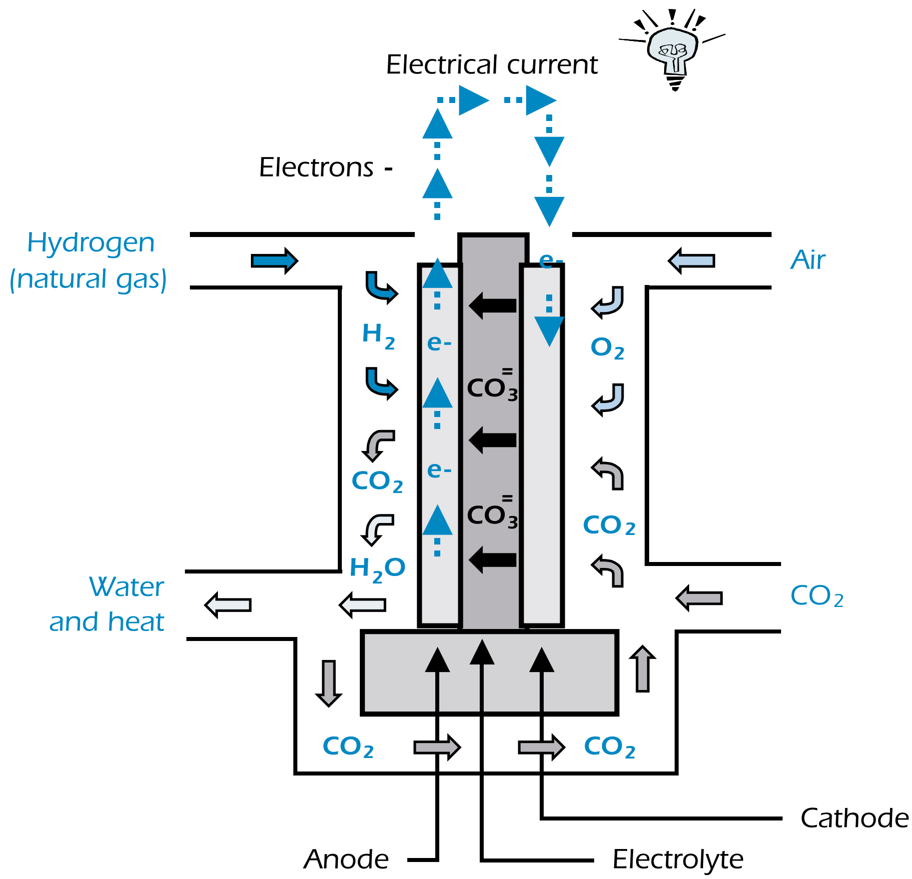
Molten carbonate fuel cells

Molten carbonate fuel cells (MCFCs) are being developed to be fuelled by natural gas. 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. MCFCs can achieve a stack efficiency 60% and overall efficiencies of up to

90% if used for cogeneration. Their resistance to poisoning is being improved. Efforts are also underway to extend their economic life, which is limited by their high operating temperature and electrolyte-induced corrosion.

Figure 3.4

The molten carbonate fuel cell concept

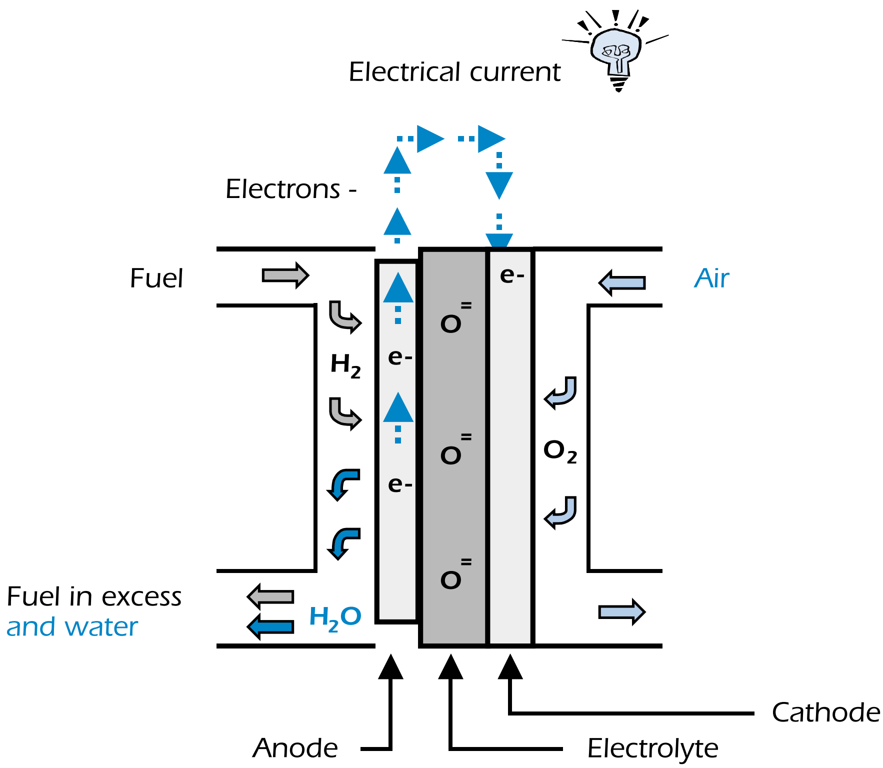


Solid oxide fuel cells

Solid oxide fuel cells (SOFCs) use a non-porous ceramic electrolyte and appear to be the most promising technology for electricity generation. When combined with a gas turbine, SOFCs are expected to achieve an electrical efficiency of 70% and up to 80-85% efficiency in cogeneration. High operating temperatures of 800-1000 °C mean precious-metal catalysts and external reformers are unnecessary, helping to reduce the cost of SOFCs. However, this is balanced by cell design problems and a slow start-up capability as a consequence of the high operating temperature. SOFCs can also 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 low-cost materials with a high durability also represents critical technical challenges for this technology.

Figure 3.5

The solid oxide fuel cell concept



Hydrogen purity

PEM fuel cells require pure hydrogen, because the Pt catalyst has little tolerance to sulphur compounds or carbon monoxide, and decomposition of the membrane is induced by impurities. This is a problem for hydrogen produced from natural gas reformers, because it would require purification before use in PEM fuel cells. In contrast, SOFCs are more tolerant of impurities due to their high operating temperature. In SOFCs, hydrogen is produced internally through a catalytic reforming process, which eliminates the need for an external reformer. In addition, carbon monoxide, a contaminant for PEM fuel cells, can be used as a fuel by SOFCs. However, SOFCs are sensitive to sulphur impurities (Table 3.1) and the current SOFCs cannot be fed with gas derived from coal unless the sulphur concentration is reduced to below one part per million. Even certain natural gas types could require purification prior to use in SOFCs. Tests show that this sulphur poisoning is reversible and that the sulphur removal cost is modest. New anode and cathode materials are under development, which are less sensitive to sulphur (Trembly et al., *2005). However, the likelihood that these materials can be successfully developed is not yet clear.*

Table 3.1

Fuel requirements of the principal fuel cells

	PEMFC	AFC	MCFC	SOFC
H_2	Fuel	Fuel	Fuel	Fuel
CH_4	Dilutent	Dilutent	Dilutent	Dilutent
CO_2&H_2O	Dilutent	Poison	Dilutent	Dilutent
CO	Poison (>10 ppm)	Poison	Fuel	Fuel
S (H_2S & COS)	Few studies, therefore not clear	Unknown (>0.5 ppm)	Poison (>1.0 ppm)	Poison

Source: Ziomek-Moroz *et al.*, 2005.

In general, the efficiency of a fuel cell is a function of the hydrogen purity and concentration. Fuel cell efficiency in one study decreased by 36% when switching from 100% H_2 to a 40% H_2 syngas mixture generated by a gasoline reformer, and decreased by 27% when switching to 75% H_2 generated by a methanol reformer (Thomas et al.*, 2000). In general, impurities degrade the fuel cells and have irreversible impacts on the efficiency of the fuel cell. In the European CUTE city bus project, PEMFCs fuelled by hydrogen from electrolysers exhibited a 4% decline in voltage and efficiency over a period of 18 months, in comparison to 10% for the buses that used hydrogen from natural gas reformers (Schuckert, 2005). However, given the ongoing state of development of most fuel cell technologies, it makes little sense to develop strict hydrogen purity standards at this stage if future PEMFCs are expected to be more tolerant of impurities.*

The cost and performance of PEM fuel cells for vehicles

PEM fuel cell cost

The cost of a PEMFC drive system can be split into the fuel cell stack, the balance of plant (BOP), the electric motors and hydrogen storage. The costs of the stack, BOP and the electric motors will be discussed in more detail in this section.

The cost of a PEMFC stack is the sum of the individual costs of the membrane, electrode, bipolar plates, platinum catalyst, peripheral materials and the cost of assembly. Apart from the cost of assembly, PEMFC costs are usually expressed per square metre of cell surface, where each square metre is equal to about 2-kW power. Table 3.2 provides an overview of current cost estimates and the cost structure. The total cost of around USD 1 800/kW seems to be dominated by the cost of the bipolar plates and the electrodes. Both these components are manually manufactured at the moment, but their future large-scale production should lead to a significant fall in their cost.

Table 3.2

Estimates of current cost of manually produced PEM fuel cells

	Cost (USD/m^2)	Cost (USD/kW)	Share (%)
Membrane	500	250	14
Electrode	1 423	712	39
Bipolar plates	1 650	825	45
Platinum catalyst	48	24	1
Peripherals	15	8	0
Assembly		8	0
Total		1 826	100

Source: Tsuchiya and Kobayashi, 2004.

Whether fuel cell components are manually manufactured, or produced by hypothetical large-scale industrial processes of some 500 000 vehicles per year, is a key point that may account for the wide range of current cost estimates for PEM fuel cell stacks. The switch from small-scale manufacturing to mass-production may be able to reduce the fuel cell cost by one order of magnitude. Another cause of confusion is that in some cases future cost targets are mixed up with actual cost figures. Finally, advances are occurring at such a rate that even a change of a couple of years in the reference year can make an important difference.

An analysis by Arthur D. Little in 2000 estimated a production cost of USD 140/kW for a large plant producing 500 000 vehicles per year. An important point is that this is for fuel cells optimised for fuel efficiency; those that are optimised for power output have significantly lower costs per kW due to higher power densities (Bar-On *et al.*, 2002). Toyota claims they can presently build fuel cell stacks at about USD 500/kW (Shuldiner, 2005). Ballard claims their fuel cell stacks, if they were produced today at the rate of 500 000 units a year, would cost USD 103/kW and that they are aiming for USD 30/kW by 2010, in line with the US-DOE target (Ballard, 2005).

The analysis below identifies for each cost component how a cost of USD 100/kW can be achieved.

Membranes

Current PEM fuel cells use DuPont-patented Nafion membranes. The material was initially developed for electrolysers for industrial chlorine production and they have been in production for more than 30 years. The membrane consists of a perfluorinated polymer chain where hydrogen ions "jump" between the SO3- sites. Different membrane materials with similar characteristics exist under different trade names (Dow, Asahi Glass and Asahi Chemicals). Typical membrane thicknesses are 50 to 175 µm. Proton mobility in the membrane is sensitive to the water content. The membrane has a low-rate of gas cross-over and a high chemical stability (Kuschel, 2005). Nafion's disadvantages include the need for humidification, their low operating temperature (<80 °C) and high cost. The low operating temperature requires a platinum catalyst which is expensive and sensitive to CO poisoning, and cooling of the fuel cell may be needed. At higher temperatures, poisoning problems are mitigated and other catalyst materials can be used. Various sulphonated plastics are being studied as alternative membrane materials (NRCAN, 2005). The choice of the membrane material is a fundamental issue, as the whole fuel cell design may change depending on the material used. Membrane materials represent an area where technical and economic breakthroughs may happen in the future. The current cost of the Nafion-type membranes can be up to USD 800/m^2, which translates into USD 250-300/kW (Apanel, 2004). Alternative materials that are not yet commercially ready may result in significant cost reductions. For example, organically modified silicates (ORMOSILs) promise a factor 10-20 cost reduction (NASA, 2004). However, such materials are not yet commercially available.

Electrode and platinum catalyst

Current systems using Nafion membranes that operate at 80 °C need 0.5 mg/cm^2 of platinum for both the anode and cathode, or 1 mg/cm^2 of platinum in total. Given a power density of 0.7 W/cm^2, this translates into 1.4 g Pt/kW. New membrane materials operating at above 100 °C will require significantly less platinum. The goal is to reduce the platinum required to 0.2 g/kW. Platinum loading at the anode can be reduced ten-fold without affecting the performance. However, reducing the amount of platinum at the cathode to 0.2-0.4 mg/cm^2, with the current Pt/C catalyst system, results in cell voltage losses of 10-20 mV and efficiency losses of 2-4% (Gasteiger *et al.*, 2004). Improved efficiency of the mass transport, the diffusion media and the electrode structures can increase the power density, and reduce the platinum load accordingly. The catalyst activity also needs to be increased compared to existing Pt/C catalysts in order to reduce the catalyst needs per kW. New electrode production technologies such as Gas Diffusion Layer technology can also reduce the platinum needs, because a larger share of the Pt surface area is available for the electrochemical reaction, enhancing the catalyst activity by up to 50% (De Castro *et al.*, 2004). Little or no gain in mass activity is anticipated for state-of-the-art Pt/C catalysts; however, new, more active Pt-alloys with cobalt and chromium appear capable of a three-fold activity increase (Adcock *et al.*, 2004).

A possible barrier to a full market expansion for fuel cells is the potential global production capacity of platinum. The production of 100 million fuel cell vehicles per year in 2050 would require 2 kt of Pt per year, assuming that 0.2 g of Pt per kW implies 20 g of platinum per vehicle. Current annual Pt production amounts to just 0.2 kt and even platinum recycling and the use of other precious metals, such as palladium and ruthenium, may not be enough to meet demand.

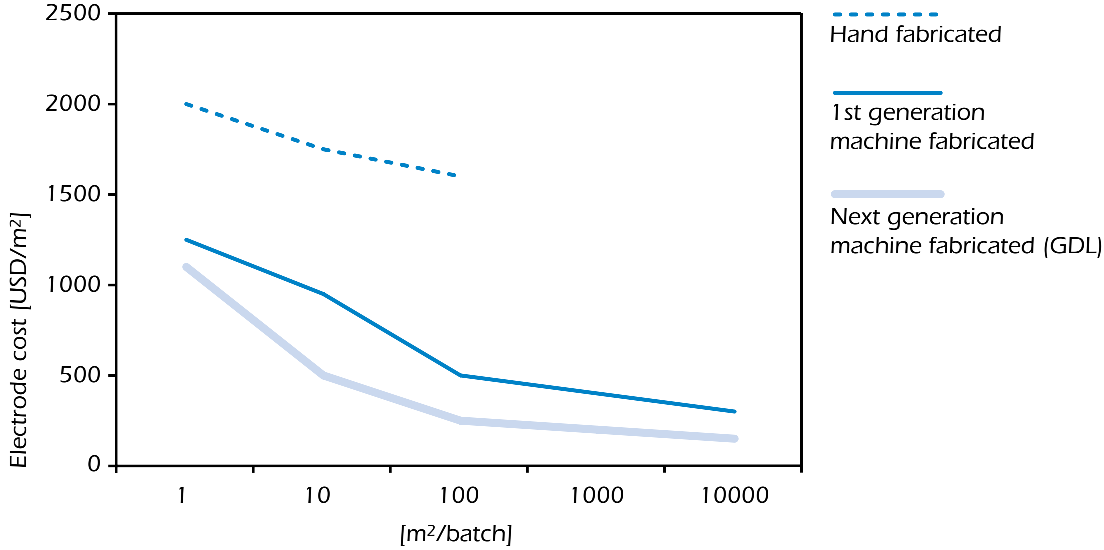
New active catalysts or high-temperature membranes that do not use Pt are critical to lowering the costs of fuel cells and ensuring the success of fuel cells in transportation. Although a platinum cost of USD 2-6/kW for the Pt catalyst (assuming a platinum price of USD 10-30/g and 0.2 g/kW) is small for current fuel cells, it could become a major obstacle to reducing long-term stack costs below USD 50/kW. The cost of electrodes depends on the production technology used and the production volume (Figures 3.6 and 3.7). Automated production on a large-scale may lower the electrode cost from USD 1 500-2 000/m^2 to USD 150/m^2.

Bipolar plates

The cost of bipolar plates can be reduced if they are mass produced. Carbon-polymer composites or coated-steel seem the best materials candidates. Bipolar plates are currently made from milled graphite or gold-coated stainless steel. Ongoing R&D is aiming to replace these materials with polymers (plastics) or low-cost steel alloys (Jobwerx, 2004; Haack, 2005; Brady *et al.*, 2005). The use of plastics would allow the use of low-cost injection-moulding production techniques. Porvair claims that its carbon/carbon bipolar plates can be produced for USD 250/kW, if the production volume were 10 000 units per year, and that the cost might drop to USD 25/kW for 1 million plates per year (Haack, 2005). A Ni-Cr alloy-cladded steel bipolar plate would cost USD 80/m^2 (Brady *et al.*, 2005). Given a power density of 2-6 kW/m^2, this translates into USD 13-40 /kW. Achieving higher power densities will be essential to reducing the cost of bipolar plates. Figure 3.7 shows the cost of injection-moulded plastic plates as a function of the batch size. Even relatively small batches would result in a drastic cost reduction from current levels, while the cost of large batches (10 000 m^2, *i.e.* sufficient for 400 to 800 vehicles at once) would drop to USD 90/m^2.

Figure 3.6

Electrode cost by production technology and volume

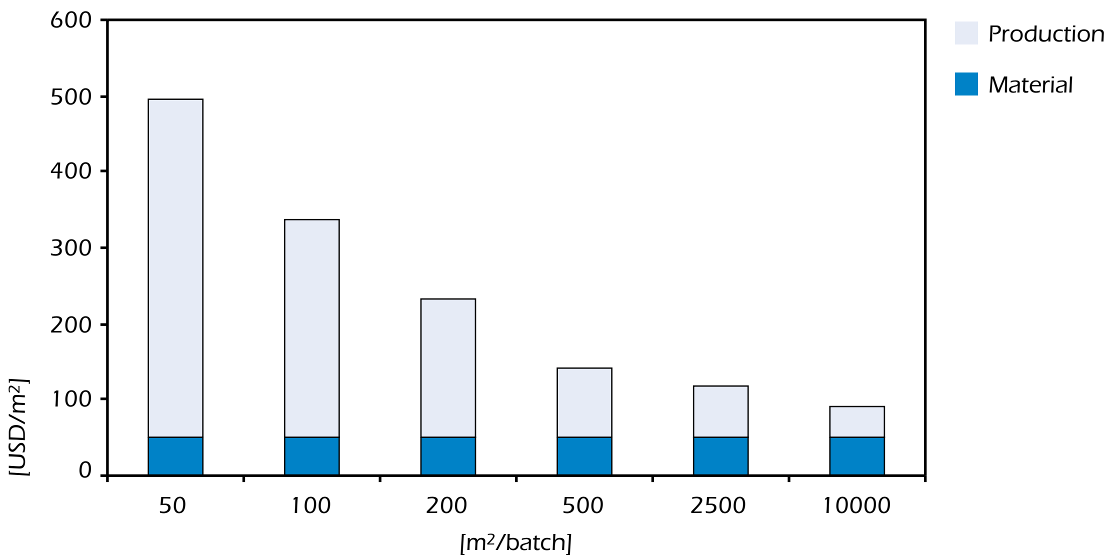


Source : De Castro *et al.*, 2004.
Note: GDL = Gas Diffusion Layer.

Key point: A factor 20 cost reduction may be achieved through a switch to machine fabrication and upscaling

Figure 3.7

The cost of injection-moulded bipolar plates by batch size



Source : Heinzel *et al.*, 2004.

Key point: A factor 10 cost reduction may be achieved through upscaling

Conclusions for the stack cost

The key changes that are needed to reduce the cost of PEM fuel cells from around USD 1 800/kW to USD 100/kW (Table 3.3) are:

- The mass-production of membranes and possibly the use of new materials (other than Nafion).
- The mass-production of electrodes based on the new Gas Diffusion Layer technology.
- The mass-production of either plastic or coated-steel bipolar plates.
- Achieving an increase in power density from 2 kW/m^2 to 3 kW/m^2.
- The production of 100 000 m^2 per year of fuel cell stacks, which equals 4 000 vehicles per year for an 80 kW vehicle.

Table 3.3

Estimated future cost of a PEM fuel cell stack (based on the identified cost reduction potential)

	Cost (USD/m^2)	Cost (USD/kW)	Share (%)
Membrane	50	17	16
Electrode	150	50	49
Bipolar plates	91	30	29
Platinum catalyst	8	3	3
Peripherals	4	1	1
Assembly		2	2
Total		103	100

It is possible that the cost of the PEM fuel cell stack could be even lower than USD 100/kW in the future. A projected cost of just USD 50/kW might be possible assuming a power density of 4 kW/m^2 and the use of cheaper electrodes and bipolar plates (Table 3.4). However, reducing costs to that level cannot be achieved with gradual improvements in existing technologies. It is based on new membrane technologies, a new electrode production technology and a different, unspecified, method to produce bipolar plates. Alternatively, an even higher current density may pose the breakthrough needed to achieve such a target, but this may limit fuel cell efficiency and life.

Table 3.4

Estimated future cost of a PEM fuel cell stack (optimistic scenario)

	Cost (USD/m^2)	Cost (USD/kW)	Share (%)
Membrane	50	13	25
Electrode	96	24	48
Bipolar plates	35	9	17
Platinum catalyst	8	2	4
Peripherals	4	1	2
Assembly		2	4
Total		50	100

Source: Tsuchiya and Kobayashi, 2004.

The cost of the balance of plant

In addition to the stack cost, fuel cells require power electronics in the form of DC/DC converters, inverters, electric motors, control electronics, as well as air and hydrogen gas humidification (depending on the fuel cell membrane type). The supply of air and hydrogen to the fuel cell must be within a fixed, very narrow, pressure range to prevent damage to the fuel cell. A cooling system is needed to cool the fuel cell and a voltage monitoring system is needed for performance and safety control.

The electric motors represent the most costly component, followed by the DC/DC converter. In the ETP model, the cost of the electric motors is defined separately from the other balance of plant (BOP) elements. A three-phase induction motor is the most likely choice for this component, as they are already widely used in electric and hybrid vehicle applications (Rajashekara, 2000). The model assumes that the electric motor cost for a car declines from USD 2 000 to USD 1 200, or from USD 25/kW to USD 15/kW (DOE, 2001).

A DC/DC converter is needed if the fuel cell and battery are of a different voltage. In the case where a fuel cell does not have a battery, the DC/DC converter is not needed, but this implies that the inverter has to cope with a wide variation in the DC-input voltage. If not properly compensated for, this variation in voltage may create stability problems in the drive system (Rajashekara, 2000). The absence of a battery also means that the re-generative braking energy cannot be captured, leading to a lower efficiency. Furthermore, an inverter is needed for DC/AC conversion in the case of AC drive motors.

The nickel-metal hydride (NMH) batteries used in current hybrid cars (Prius) cost around USD 2 500 for a storage capacity of 1.5 kWh (giving a 20 km driving range). The Prius battery is designed to maximise battery life and to last the life of the vehicle. New generation batteries are 15% smaller, 25% lighter, have 35% more specific power and cost some 36% less. Li-ion batteries, currently used in the Toyota Eco-Yaris, hold the promise of further cost reductions.

The current cost of the balance of plant for a FCV system is around USD 1 000-1 500/kW, about half of which is accounted for by the power converter. However, the cost of the balance of plant should be reduced dramatically once large-scale production is introduced. In this study the total cost of the balance of plant is assumed to decline from USD 4 500/car to USD 1 350/car, or from USD 56/kW to USD 17/kW.

PEM fuel cell performance

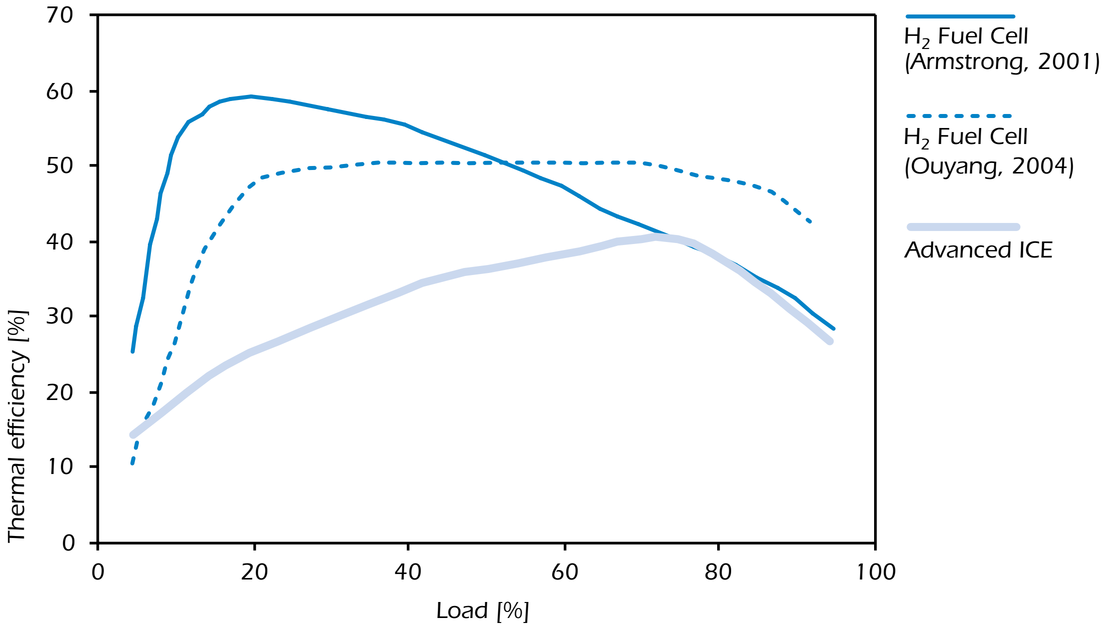
Fuel cell efficiency

The theoretical efficiency of the fuel cell stack can be calculated as the ratio of the actual cell voltage to the theoretical cell voltage. Assuming a practical value for the cell voltage of around 0.7 V, to be raised to 0.75 V by improved fuel cell design (Gasteiger *et al.*, 2005), and a theoretical cell voltage of 1.17 V, the theoretical maximum efficiency is around 64%. In real-world applications, certain losses and the drain of ancillary equipment needs to be allowed for. Losses due to transformation and in the electric motors, and the electricity needs for gas treatment, cooling, pumping, etc., all lower the efficiency below the theoretical level.

Fuel cells are significantly more efficient (up to three-times) than internal combustion engines (ICEs) when operating at partial loads, whereas at high loads the efficiency of the two systems is similar (Figure 3.8). However, on the road, the higher efficiency of the fuel cell engine is to some extent offset by higher parasitic losses and the 10% weight penalty of fuel cell vehicles (Ahluwalia, 2004). The key to obtaining high on-road fuel cell economy lies in maintaining the high efficiency of fuel cell systems at low load factors. Besides a high-performance fuel cell stack, low parasitic losses are therefore critical. Different sources give quite different performance gains for fuel cells compared to ICEs. The difference may be explained by whether parasitic losses are accounted for or not (*i.e.* whether the fuel cell stack efficiency or the FCV efficiency is being presented).

Figure 3.8

The thermal efficiency of ICE and fuel cell vehicles by load factor



Source: Armstrong, 2001 and Ouyang, 2004.

Key point: The main FCV efficiency benefits occur at partial load

Impact of the power density

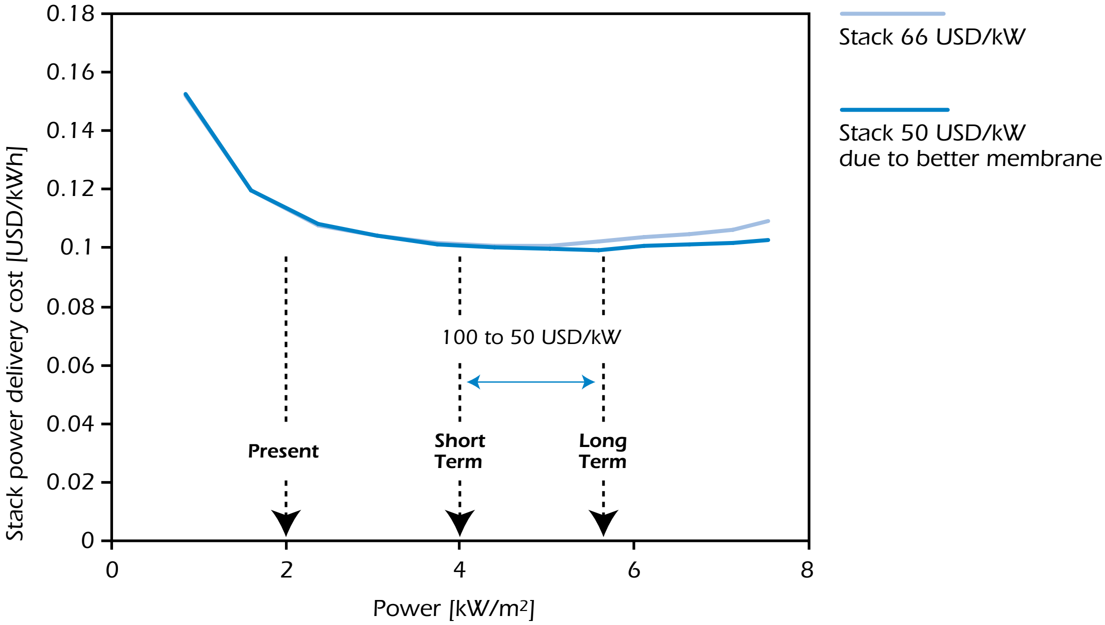
If the cost of fuel cells is reduced below USD 100/kW, then the basic materials cost becomes a significant component of the total cost. The materials cost can be reduced by increasing the power density. However, there is a trade-off, because higher power densities results in higher energy losses, lower efficiency levels and therefore lead to higher costs per unit of produced energy. Depending on capital costs, hydrogen costs and the efficiency loss, there exists an optimal power density which minimises the cost per unit of energy produced.

Current cells achieve 0.3-0.6 A/cm^2 current density at 0.6-0.7 V voltage. The power density (*i.e.* voltage multiplied by the current density) achieved in laboratory conditions is 1.8-4.2 kW/m^2. In real-world conditions, stacks achieve values at the lower end of this range (2 kW/m^2). However, a value of 3 kW/m^2 is achievable with minor improvements in the membrane and is the value assumed in this study. Higher values of 4-6 kW/m^2 would necessitate improved membrane materials.

If the price of hydrogen is assumed to be USD 15/GJ and the fuel cell cost to be USD 100/kW for a power density of 2-3 kW/m^2 and USD 66/kW for a power density of around 4-5 kW/m^2, then the minimum energy cost would occur at the higher power density. However, it is anticipated that mass-transport induced energy losses will soon be reduced by at least 50% (Gasteiger *et al.*, 2005). This improvement will mean that the least-cost design for the energy produced occurs at the higher power density of 5-6 kW/m^2, with the stack cost reduced to USD 50/kW.

Figure 3.9

The delivered power cost of FCVs



Key point: Higher power densities reduce the fuel cell's cost substantially

Fuel cell durability

Fuel cell durability is critical to the life-cycle cost of fuel cell application. The goal for stationary applications is an operating life of 40 000-60 000 hours or 5-8 years of operation. In mobile applications a life of 3 000-5 000 hours for cars and up to 20 000 hours for buses is required (Knights *et al.*, 2004). The operating life of PEM fuel cells depends to a large extent on the operating conditions, such as the external temperature at start-up, excessive or insufficient humidification, and fuel purity. The average life span of PEM fuel cells for vehicles is currently about 2 200 hours or 100 000 km. However, this can vary from 1 000 to 13 000 hours depending on the test conditions (Knights *et al.*, 2004). Doubling the average life and reducing the variability in average life will be imperative to gain consumer acceptance. Given the significant advances in lifetime (durability) during recent years and the wide gap between average and best durability, further improvements should be feasible. Fundamental fuel cell design changes, such as different membrane materials and new high-temperature catalyst materials, may increase durability. The operating life of auxiliary equipment will also need to be addressed.

PEM fuel cell applications: light duty vehicles

Hydrogen-fuelled internal combustion engines are a proven technology. Some ICE components and systems may require adaptation to burn hydrogen instead of hydrocarbons, but no major technology innovation is needed. The more favourable compression ratio such engines achieve could mean they are more efficient than gasoline engines. However, the use of hydrogen in fuel cell vehicles results in fuel economy of two to three times more than a conventional gasoline ICE vehicle (Ahluwalia *et al.*, 2004). The higher efficiency also results in less demanding requirements for on-board hydrogen storage, which is a key issue for hydrogen vehicles. In addition, burning hydrogen in combustion engines produces nitrogen oxides (NOx) emissions, while hydrogen FCVs emit only water, thus maximising the environmental benefits of hydrogen.[10]

The major car producers currently build and test some 200 FCVs per year for demonstration projects, but significant technology and economic hurdles need to be overcome before FCVs are a viable proposition for mass-production. If FCVs are to be successful, they need to be price competitive and meet, or exceed, users' needs and expectations. They should perform at least as well as conventional vehicles in terms of driving range, start-up time, acceleration, reliability and durability. Current FCVs are already competitive in terms of efficiency, emissions, silent driving and acceleration. However, further R&D is needed to reduce their cost and improve their durability.

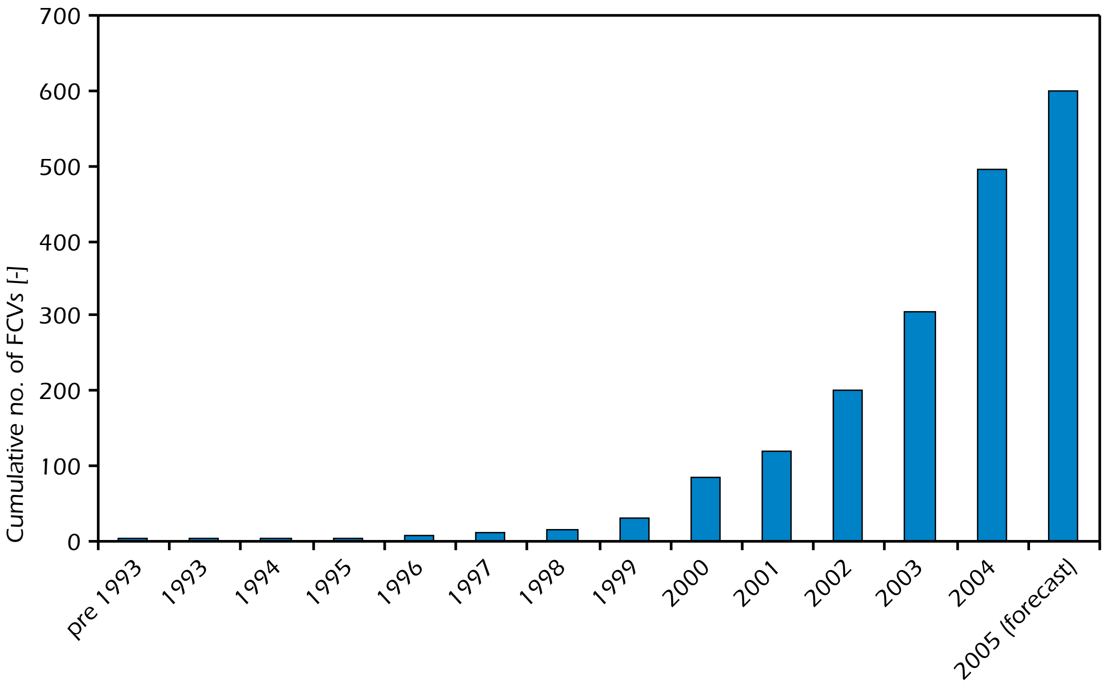
In addition, a "chicken-or-egg" problem exists: an expensive hydrogen supply system will not be established without sufficient demand, and the demand for FCVs is unlikely to grow without the low-cost hydrogen and extensive refuelling network that is provided by the hydrogen supply infrastructure. The potential use of fuel cells in the transportation sector has been considered since the late 1980s, and the potential of the "chicken-or-egg" problem to hinder the use of hydrogen was identified in the 1990s. Car manufacturers devised a strategy to get fuel cell cars on the road without the need for hydrogen infrastructure (Renzi *et al.*, 2000 and Romano, 2003). The strategy focused on reforming hydrogen on-board the vehicle from hydrocarbons. The goal was the introduction of mass-produced FCVs at a competitive cost, without the need for an extensive hydrogen supply network in the initial market introduction phase.

Methanol was the prime candidate for on-board reforming. However, methanol and methyl tertiary butyl ether (MTBE) developed a bad reputation due to toxicity and MTBE's miscibility with water, which results in ground-water pollution. The focus was then switched to on-board gasoline reforming, but this development has also proved impractical. One reason is that the higher reforming temperature of gasoline results in a long start-up time, well in excess of the 30 seconds that are considered acceptable. In addition, sulphur impurities in gasoline poison the fuel cell's platinum catalyst. In conclusion, the on-board reforming of hydrogen poses significant additional technical and economic problems over and above the already significant ones faced by FCVs that have on-board hydrogen storage. As a result, the current focus is on solving the technical and economic problems associated with FCVs that rely on the on-board storage of hydrogen.

10. NOx emissions from hydrogen ICEs will be 90% lower than for a gasoline ICE, because the engine can operate in the so-called "lean-burn" mode with an excess of air. This leads to lower engine temperatures and less NOx production. A lean ratio also helps prevent pre-ignition and back-firing. The specific characteristics of hydrogen combustion require some combustion engine adjustments, such as the use of superchargers or sequential injection of air and fuel (Cho, 2004). These adjustments do not necessarily prevent the use of other fuels in the same engines. For example, BMWs hydrogen-fuelled ICE vehicles can run on hydrogen or on gasoline. This dual-fuel capability may become an essential feature of the introduction of hydrogen in the transition period.

Figure 3.10

Growth in the global FCV fleet



Source: Adamson, 2005.

Key point: *FCV sales are in the range of a few hundreds a year, compared to 50 million passenger cars a year*

The efficiency of fuel cell vehicles

The technical fuel efficiency of FCVs will depend on the stack efficiency and the characteristics of the drive system. Assuming that theoretical efficiency of the fuel cell stack is around 64% (Gasteiger *et al.*, 2005) and that the electric drive train efficiency is typically 90%, then the overall fuel cell systems efficiency is 58%. However, it is possible that the current fuel cell stack efficiency of 58% may increase to 64% by 2020 (METI, 2005a). The efficiency of the FCV may increase from 50 to 60% during the same period.

A comparison of the average efficiency of current ICE vehicles (ICEVs), hydrogen ICE vehicles (HEVs) and FCVs is presented in Figure 3.11.[11] This data is based on a Japanese demonstration project that began in 2002 and presently involves 59 FCVs (METI 2005b). The FCVs proved to be at least a factor of 1.8-2 times more efficient than ICEVs, while the best FCVs are three-times more fuel efficient than conventional ICEs.[12] It is anticipated that future FCVs will be four-times more efficient than conventional ICEs. However FCVs are only 1 to 1.5 times more efficient than HEVs.

11. Figures in the graph have been corrected for vehicle weight, as the current FCV weight is about 1 700 kg, significantly higher than an ICEV's weight (METI 2005b).

12. The comparison suggests that most Japanese vehicles operate, on average, at partial load, where the efficiency benefits of FCVs are substantial. This may not apply to other regions with less dense traffic and higher average speeds.

A comparison between the future efficiency of ICEVs and FCVs is complicated by a number of factors, including:

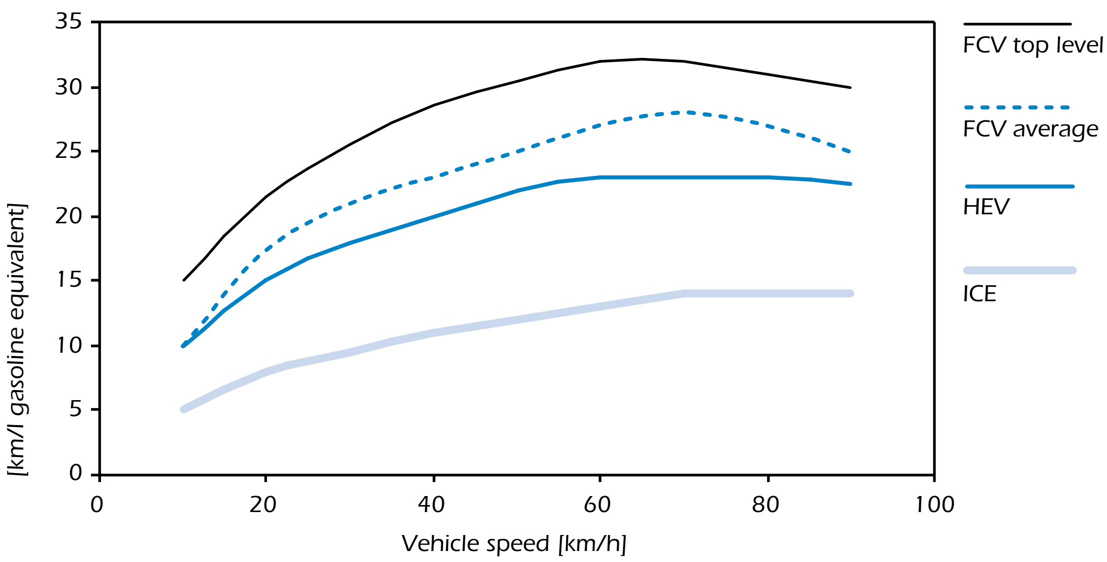
- The efficiency depends on the drive cycle characteristics.
- The efficiency of both FCVs and ICEVs will improve over time.
- A switch from ICEVs to FCVs may result in very different vehicle designs, with important efficiency implications that are not apparent at this time.

A gasoline/diesel ICE achieves an efficiency of 40% in its optimal load range, but this tends to fall quickly in other operating conditions. On-road, the engine operates at partial load for most of the time, resulting in an average efficiency of less than 25%. Including the transmission (95% efficiency) and other loads, the average overall efficiency is at or below 23%. The actual value varies depending on the specific engine technology.

FCVs are significantly more efficient than ICEs in urban traffic, where partial loads are common. Modelling suggests that the average fuel consumption of an FCV is 2.5-2.7 times lower than for 2001 reference cars in the United States. It ranges from a factor of two in highway traffic to a factor of three in urban traffic (Ahluwalia, 2004). However, the efficiency benefits are sensitive to the drive cycle characteristics. Hybrid FCVs may achieve 10-15% higher efficiency than FCVs without the recovery of braking energy.

Figure 3.11

The on-road vehicle efficiency of ICEVs, HEVs and FCVs



Source: METI 2005b.

Key point: *FCVs are 2-3 times more efficient than ICEVs and 1-1.5 more than HEVs*

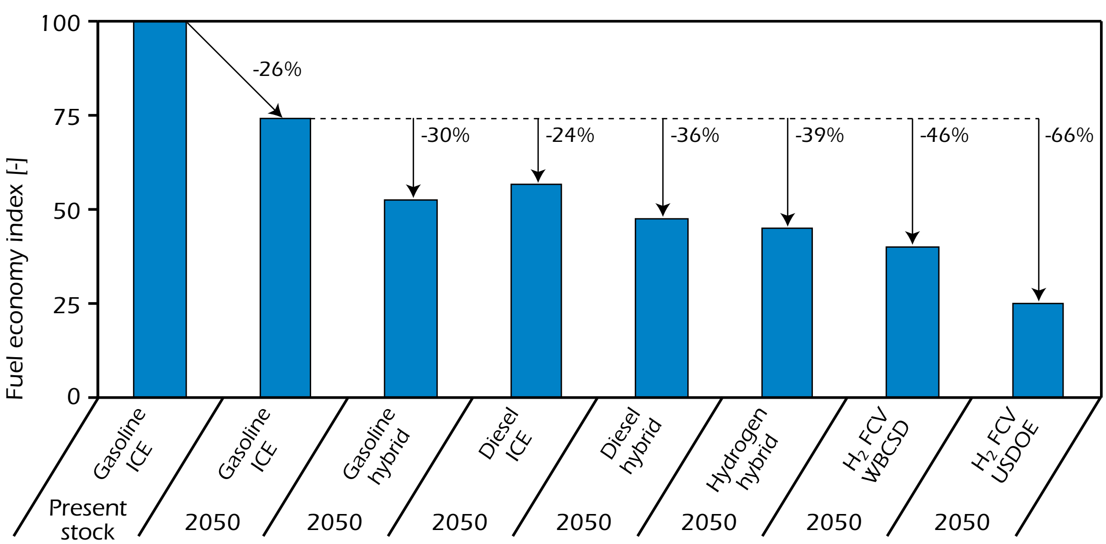
Both the efficiency of FCVs and ICEVs are expected to improve over time. CO_2 emissions from new cars sold in the EU-15 decreased by 11.8% between 1995 and 2003, which is a measure of efficiency gains. A further improvement in the average efficiency of ICEVs of about 15% is targeted for 2008/2009, compared to 2003 (EC, 2005). The improvement will be due to the introduction of a range of new technologies, including: variable-valve timing and lift electronic control systems, dual and sequential ignition, gasoline direct injection, turbo and twin-turbo engines or variable compressors, and advanced transmissions. Further technology improvements, such as intelligent drive systems and continued weight reduction, could also be applied to FCV drive systems.

FCVs also offer the opportunity for specific energy-efficiency improvements not available to ICEVs. FCVs can recover the energy in braking if they are equipped with a battery, similar to the existing ICE-hybrid vehicles. This may yield a few percentage points up to 15% fuel savings, depending on the drive cycle characteristics. Fundamental re-design of the vehicle could make FCVs about 300 kg lighter than a comparable ICEV and result in a fuel saving of 15% (Watanabe, 2005). If both effects are accounted for, FCVs might be 2.26 to 2.93 times more efficient than an advanced ICEV. The so-called "skateboard design", where the fuel cell is integrated in the bottom-plate of the car and each wheel is equipped with its own electric motor, could make the transmission system unnecessary. In this case steering, braking and other vehicle systems could be controlled electronically rather than mechanically.

The United States Department of Energy takes some of these factors into account in its projections, resulting in a relative efficiency factor of 2.27 (*i.e.* FCVs use 2.27 times less fuel than an ICEV) in 2010 and 2.95 in 2050. This is a 66% gain compared to advanced ICEs in 2050 (Figure 3.12). In this study, the uncertainty about the efficiency gain of FCVs over advanced ICEs is explicitly taken into account. The average fuel savings due to the higher efficiency of new ICE cars sold in 2050 compared to the average stock efficiency in 2000 is set at 26%. This is based on a study carried out by the IEA in co-operation with the World Business Council for Sustainable Development (WBCSD, 2004 and Figure 3.12). The efficiency gain of the average vehicle stock in 2050 is 19% in the WBCSD study. The relative efficiency gain of FCVs compared to advanced new ICEVs ranges from 46% to 66% (WBCSD, 2004).

Figure 3.12

Potential efficiency improvements for LDVs



Source: WBCSD, 2004.

Key point: 30% to 66% less fuel is needed by more efficient vehicles than the 2050 reference ICEV

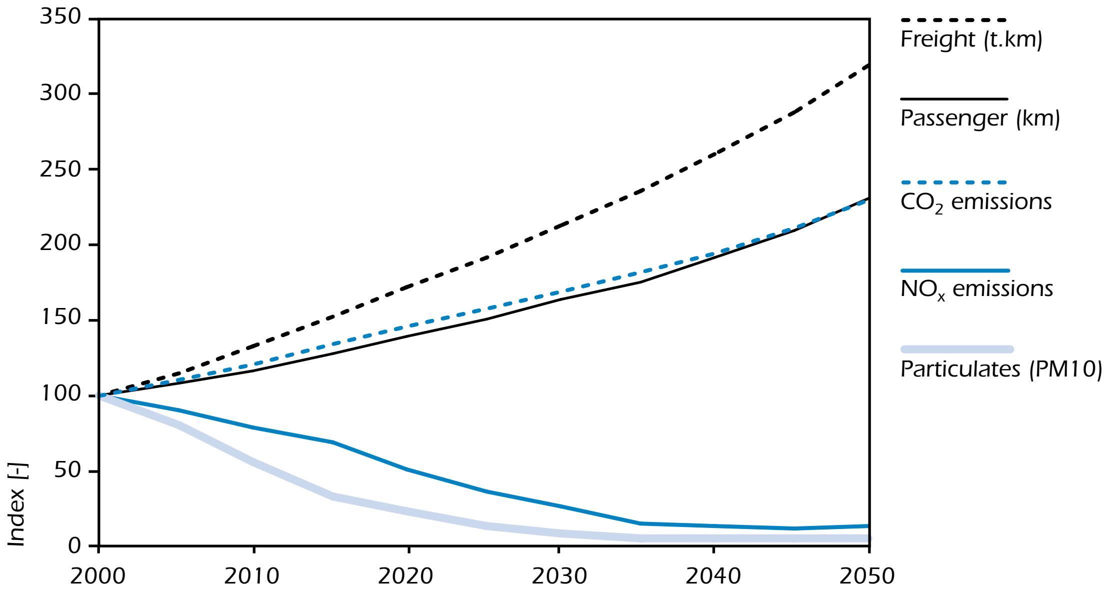
Impact of FCVs on local air pollution

The transportation sector is a major contributor to environmental problems. It is the source of over 30% of global NOx emissions, 23% of CO_2 emissions and 18% of CO emissions. Its contribution to local environmental problems is even higher, because it is also a major emitter of organic compounds and particulates (Metz, 1998; UNEP, 2002; WBCSD, 2004). Acid rain induced by NOx and SO_2 emissions, health problems caused by exhaust particulates and secondary particles, and hydrocarbon emissions have been the subject of extensive research. It is estimated that air pollution from vehicles results in 0.8 million deaths (1.4% of all deaths) and 7.9 million disability-adjusted life years (0.8% of all DALYs) globally each year. However, these figures are likely to under-estimate the problem, as they do not include the effects on induced diseases because of limitations in the epidemiologic database. If these diseases were taken into account, the burden in terms of negative public health externalities would be even higher (WHO, 2002).

Policies and measures to reduce the emission of pollutants have been successfully implemented in many industrialised countries. For example, over the past decade in Europe, SO_2, particulate, NOx and hydrocarbon emissions have declined significantly (Eurostat, 2004). These emissions will decline further as the result of increasingly strict legislation, fuel improvements and technological advances in off-gas treatment for both gasoline and for diesel engines (Figure 3.13). If stringent air pollution measures are adopted in developing countries, then emissions of CO_2 will remain the main challenge from an environmental perspective.

Figure 3.13

Projections of transport demand and emissions with no new policies



Source: WBCSD, 2004.

Key point: *While local pollutants will decline, CO_2 emissions will continue to increase*

The current trend in vehicle ownership is towards larger and heavier cars that use more fuel. Also, the modal-switch trend is away from energy-efficient, slow transportation solutions (*e.g.* from bus to car, and from car and train to airplane). The emphasis is on energy-intensive, high-speed modes. While traffic management systems and advanced ICEs may help to reduce fuel consumption in the short term, additional energy efficiency measures and fuel switching will be the only way to reduce CO_2 emissions in the long term. Hydrogen ICEVs and FCVs could significantly contribute to reducing CO_2 and other emissions.

Cost of the fuel cell vehicles

At present, hydrogen FCVs are more expensive than conventional ICE vehicles. In 2002, Toyota offered the first semi-commercial hydrogen FCVs for demonstration purposes at USD 10 000 per month on a 30-month lease (Wards, 2003). If this leasing price fully covered the vehicle production costs, it would imply a fuel-cell system cost of around USD 4 000/kW for a 75kW system, or a vehicle cost of USD 300 000. In addition, the life span of current fuel cell stacks is shorter than the vehicle life and might require replacing two or three times during the life of the vehicle. However, a number of studies suggest that in the coming decades the cost of fuel cells will decline quickly as a consequence of mass-production and technology learning, and that their durability will also improve. Furthermore, the required fuel cell power output (kW) may be considerably lower than for current cars and light-trucks, as FCVs will be lighter and more efficient.

Recent literature suggests that manufacturers are fairly confident that current RD&D programmes should be able to bring the cost of production down to a few hundred dollars per kW in a relatively short period. However, even at this price FCVs will not be competitive with conventional ICE vehicles, whose cost averages a mere USD 30/kW. Costs will therefore have to fall by even more than current expectations, which will necessitate large-scale production and "technology learning".

However, FCVs could still be introduced while they still have a high incremental cost if government subsidies were used to help initial sales. In this case, their success will depend on very quick cost reductions to avoid the need for substantial government subsidies. Fortunately, rapid cost declines are not an unreasonable assumption, as cost reductions due to technology and process improvements (mass-production, streamlining, de-bottlenecking, etc.) have been seen to occur in the past for a wide variety of new technologies. However, learning rates vary considerably across different technologies and relatively small differences in the learning rate can cause large differences in the rate at which costs decline over time (IEA, 2000).

The cost of a fuel cell vehicle is the sum of the costs for the fuel cell stack (including power electronics and other peripherals), the hydrogen storage system, the electric engine, the battery (if a hybrid system is used) and the reformer (if fuels other than hydrogen are used). It is estimated that the cost of a FCV might decline to between USD 22 000 and USD 27 000 in 2030 (Table 3.5)[13]. The key assumptions in Table 3.5 are that PEM fuel cell costs would decline over time to between USD 35/kW and USD 75/kW and that the optimistic USD 35/kW for the PEM fuel cell stack could occur between 2025 and 2040. The incremental cost of a fuel cell vehicle in 2030 over a conventional vehicle would then range from USD 2 200 to USD 7 625 per car. These estimates suggest that in the short-term the fuel cell stack and the peripherals represent the bulk of the incremental cost, but that the hydrogen storage system, the electric drive system, and the battery may become important in the long term.

13. The data in Table 3.5 is the basis for the FCV cost assumptions used in the ETP model.

Table 3.5

Estimated costs of a hydrogen fuel cell vehicle (80kW FCV)

	2005	2010	2030 Optimistic reduction	2030 Optimistic, but slower	2030 Pessimistic reduction
PEM fuel cell stack (USD/kW)	**1 800**	**500**	**35**	**65**	**75**
Gaseous hydrogen storage at 700 bar (USD/kg)	**1 000**	**500**	**225**	**375**	**500**
DME reformer (USD/kW net)	300	150	65	75	75
Gasoline ICE (USD/kW)	30	30	30	30	30
3-way catalyst (USD/unit)	430	430	430	430	430
Gaseous hydrogen storage at 700 bar (USD)	**4 000**	**2 000**	**900**	**1 500**	**2 000**
MeH2 hydrogen solid storage (USD)			2 000	2 000	2 000
DME storage tank (USD)	1 500	1 500	1 500	1 500	1 500
Fuel cell stack (USD)	**144 000**	**40 000**	**2 800**	**5 200**	**6 000**
Electric engine (USD)	**1 900**	**1 700**	**1 200**	**1 400**	**2 025**
DME reformer (USD)	24 000	12 000	5 200	6 000	6 000
Ref. Conventional ICE vehicle (USD)	19 450	19 450	19 450	19 450	19 450
Ref. Conventional vehicle w/o engine (USD)	17 050	17 050	17 050	17 050	17 050
DME on-board reforming FCV (USD)	188 450	72 250	27 750	31 150	32 575
Hydrogen FCV (USD)	**167 000**	**60 750**	**21 950**	**25 150**	**27 075**
Hydrogen FCV drive system cost (USD/kW)	**1 875**	**545**	**60**	**100**	**125**

To assess the impact of the learning rate on the total cost of FCVs, two scenarios were developed with an optimistic and a pessimistic learning rate. In both cases, sales of FCVs begin after 2010 at an incremental cost over similar ICE vehicles of USD 40 000. The annual rate of production intitally grows slowly, but rapidly increases after 2020. Given the current production volume of around 200 vehicles per year, the cumulative production in 2010 was set at 1 800 vehicles and reaches 700 million in 2050. This assumes that hydrogen FCVs account for all light-duty vehicle sales in OECD regions in 2050 and half of all vehicle sales in non-OECD regions. The learning rate, or the so-called "progress-ratio", is set at 0.78 in the optimistic case and at 0.85 in the pessimistic case. This translates into fuel cell costs declining by 22% for each doubling of cumulative production in the optimistic case and by only 15% in the pessimistic case. This range of improvement in the progress-ratio is well within the observed range for other technologies, which has typically been between 0.75 and 0.9. The approach is based on the assumption of "global learning" (*i.e.* across industry and countries), which can reflect either the broad technological exchange between companies, or a market that is dominated by a few companies. A minimum cost of USD 45/kW has been assumed for the FCV system. This floor is based on the cost of basic materials needed for the fuel cell system, multiplied by a factor of two to account for manufacturing costs.

The results are shown in Table 3.6 for each five year period, 2010 through 2050, with cumulative production levels and costs (undiscounted) over the same period. Given these assumptions, in the optimistic case, the cumulative *incremental cost* of FCVs amounts to USD 1 trillion by 2050, whereas in the pessimistic case it amounts to USD 2.3 trillion. In the optimistic case, the per vehicle cost is about USD 500 higher than for a conventional ICE vehicle in 2050, whereas it remains about USD 3 000 higher in the pessimistic case. The end-point for cost reductions will also be a very important determinant of the total incremental costs. For example, if the incremental cost per vehicle drops rapidly from USD 40 000 to 5 000 and then plateaus at that level, the cumulative incremental costs could be much higher than estimated here.

The final cost floor for FCVs and the rate of reduction are very important in order to minimise the cumulative incremental costs of hydrogen FCVs. Without an order-of-magnitude cost reduction before commercial production, followed by another rapid order-of-magnitude reduction in costs after mass-production begins, the total incremental costs of these vehicles could be in the range of trillions of US dollars. Clearly, the lower the vehicle costs can be pushed through pure RD&D, the lower the cost reduction needed during the commercialisation stage and the greater the chances of success. On the other hand, relying on RD&D alone to reduce costs may not be feasible and could delay market introduction of FCVs to such an extent that other technology or fuel options, such as plug-in hybrids or biofuels, could dramatically reduce the market opportunities for hydrogen FCVs.

Table 3.6

Fuel cell vehicle cost reduction scenarios

	2010	2015	2020	2025	2030	2035	2040	2045	2050
Assumptions used in both cases									
Cumulative fuel cell vehicle production, OECD (millions)	0.00	0.04	0.21	1.48	8.39	43.66	133.26	285.34	502.39
Cumulative fuel cell vehicle production, world wide (millions)	0.00	0.04	0.22	1.53	8.63	45.27	143.70	349.80	727.52
Fuel cell vehicle share of sales, OECD	0.0%	0.1%	0.2%	1.0%	5.0%	25.0%	50.0%	75.0%	100.0%
Fuel cell vehicle share of total vehicle stock, OECD	0.0%	0.0%	0.1%	0.4%	2.2%	6.3%	13.1%	21.7%	31.0%
Optimistic case results									
FCV cost, optimistic case (0.78 progress ratio) (USD/kW)	545	207	134	90	69	58	54	51	50
Total incremental cost of fuel cell vehicles, cumulative (USD bn)	0.1	0.6	2.1	7.8	27.2	95.6	243.6	514.0	964.9
Pessimistic case results									
FCV cost, pessimistic case (0.85 progress ratio) (USD/kw)	545	284	207	148	114	92	81	74	69
Total incremental cost of fuel cell vehicles, cumulative (USD bn)	0.1	0.9	3.4	15.3	60.0	226.1	585.2	1 226.6	2 264.2

Note: The total incremental cost is undiscounted.

Hydrogen hybrids or hydrogen FCVs?

Hydrogen and fuel cells offer important synergies, but hydrogen can also be burnt in internal combustion engines and FCVs can use fuels other than hydrogen if they are equipped with an on-board reformer. However, given that on-board reforming looks like a costly and technologically challenging option, only the competition between hydrogen-hybrid ICEVs, hydrogen FCVs and hydrogen-hybrid FCVs looks likely to develop. A standard FCV does not have a braking energy recovery system. The hybridisation of an FCV involves using a larger battery pack with regenerative braking, which can improve the efficiency of a FCV. This configuration is known as a hydrogen-hybrid FCV.

Both hydrogen FCVs and hydrogen burning ICEVs emit no CO_2, but FCVs have a higher efficiency than the hydrogen ICEVs and do not emit NO_x. However, the NO_x emissions from a hydrogen-hybrid ICEV are reduced by a factor of 10 compared to a gasoline ICE; vehicle hybridisation reduces the fuel needs and the emissions even further in comparison to a hydrogen-burning conventional ICEV. The main reason for this is that braking energy is recovered and the efficiency of a battery in combination with an electric engine is much higher than the fuel cell efficiency, especially at partial loads.

Table 3.7 compares retail prices of a gasoline ICE vehicle, a hydrogen-hybrid ICE vehicle, a fuel cell vehicle and a hybrid fuel cell vehicle (CONCAWE, 2003). This data was meant to be applicable to the year 2010, but given current trends they seem more appropriate to the likely costs in 2015-2020. However, they do not account for the full cost reduction potential due to technology learning. The energy efficiency of the hybrid FCV is higher than the efficiency of a standard FCV, but this requires additional investments of around USD 1 500 per vehicle.

Table 3.7

Estimated retail prices of ICEs, hybrids and FCVs

(USD/vehicle)	ICE Gasoline	Hybrid ICE H_2 70 MPa	FCV H_2 70 MPa	Hybrid FCV H_2 70 MPa
Baseline vehicle	20 206	20 206	20 206	20 206
Fuel tank	156	5 391	3 379	3 019
Engine + transmission	2 888	2 888	10 500	10 500
Turbo	225	225	0	0
Stop & go system	250	0	0	0
EURO IV exhaust after-treatment	375	0	0	0
Electric motor (AC induction)+controller	0	473	2 531	2 531
Battery (Li-Ion)	0	1 844	0	1 844
Total Vehicle Retail Price	**24 100**	**31 026**	**36 616**	**38 100**

Source: CONCAWE, 2003.

Table 3.8 presents the additional annual vehicle cost and CO_2 emission reductions for different vehicle types assuming a 15% annuity and that hydrogen production results in no CO_2 emissions. The fuel cost was assumed to be USD 10.6/GJ for gasoline (USD 29/bbl crude oil) and USD 18.8/GJ for hydrogen. The estimated CO_2 emission reduction cost for the hydrogen-hybrid ICE is USD 655/t of CO_2 and around USD 1 100/t of CO_2 for the hydrogen FCV. These costs are rather insensitive to the oil price, because the capital cost is by far the most significant cost. Interestingly, if the hydrogen tank cost (USD 720/kg H_2) for a hydrogen-hybrid ICE, which represents 75% of the additional cost for this vehicle, could be reduced through technology learning, then the CO_2 emission abatement cost would decline significantly. In fact, hybrid ICEVs would benefit more from such a cost reduction than a FCV, because they need a larger tank. The additional cost for the FCV is dominated by the cost of the fuel cell. This is assumed to have declined to USD 105/kW. If this cost could be halved, then the CO_2 emission reduction cost would decline by a third.

Without further technology cost reductions beyond those assumed in Table 3.8, hydrogen and fuel cell vehicles represent very expensive CO_2 emission abatement options. The CO_2 emission abatement cost of between USD 655 and USD 1 179 per tonne compares poorly with estimates of the costs needed to stabilise emissions of USD 10-100/t of CO_2.

Table 3.8

Hydrogen hybrids and FCV CO_2 emissions reduction cost

	Incremental invest. cost (USD/vehicle)	Annual fuel use (GJ/yr)	CO_2 reduction (t/yr)	Additional cost (USD/yr)	Cost of CO_2 reduction (USD/t)
Gasoline	0	23.8	0.00	0	
Hydrogen hybrid	6 926	18.6	1.73	1 136	655
Hydrogen FCV	12 516	11.8	1.73	1 845	1 064
Hydrogen-hybrid FCV	14 000	10.5	1.73	2 045	1 179

Source: CONCAWE, 2003.

This brief analysis suggests that hydrogen-hybrid ICEVs may be an economic transition strategy to FCVs and could represent an option to build up a hydrogen refuelling network.

Niche markets for PEM fuel cells in the transport sector

The introduction of FCVs is a challenge, because of the low cost of conventional ICEVs and the low utilisation factor of private cars. Commercial buses have much higher utilisation rates and represent a more attractive market for highly efficient but more expensive fuel cells vehicles. Larger vehicles also offer easier solutions to the large space requirements of hydrogen on-board storage. In addition, fuel cells could compete effectively with batteries (instead of low-cost ICEs) in niche transportation markets such as wheelchairs, carts and forklifts.

Buses

Almost 80 fuel cell buses (FCBs) are in use world wide in several demonstration projects. The European CUTE and ECTOS projects account for 30 buses that are currently part of the public transport systems in several European cities. Today's FCBs are nearly all powered by PEM fuel cells that range in power from around 70 kW (hybridised with a battery) to 200 kW. More than 75% of current FCBs have compressed hydrogen gas storage systems. The DaimlerChrysler Citaro FCBs used in the CUTE project have a 200-300 km range, carry 60-70 passengers, are powered by a 250 kW PEM fuel cell (200 kW shaft power) and have up to 44 kg of compressed hydrogen gas stored at 350 bar. In urban traffic with a lot of stops, a FCB has the potential to offer significant efficiency gains compared to a conventional ICE powered bus. However, given their early stage of development, the Citaro buses use 40-50% more fuel than a comparable diesel ICE (Schuckert, 2005). In the long-run it is hoped this will reverse and they will use 20% less fuel.

Buses are potentially the easiest market in which to introduce fuel cells in the transport sector, because refuelling is concentrated at fleet depots. On-board fuel storage is also easier with buses; gaseous storage at 350 bar under the roof seems to be the technology of choice. Finally, the annual mileage of a bus is much higher than that of a passenger car, helping to recuperate the additional capital cost more quickly. However, the current cost of FCBs is not entirely clear. Estimates indicate a purchase price for the Citaro buses of around USD 1.5 million each, but this includes all maintenance services for two years (GEF, 2004). Given similar unit power is needed and assuming a price of around USD 2 000/kW, the additional (incremental) cost per vehicle over a conventional bus should be in the range of USD 0.5-1 million. This is broadly similar to other recent estimates of FCB costs (Table 3.9).

Table 3.9

The cost of bus engine systems

	Cost (USD/bus)	Incremental cost (USD/bus)
Diesel ICE	500 000	-
Diesel hybrid electric	600 000-630 000	100 000-130 000
Natural gas bus	540 000-560 000	40 000-60 000
Hydrogen FCV	1 000 000	500 000

Source: Adamson, 2004.

Note: The cost for hydrogen FCV buses is based on a production volume of some 100 buses a year, a ten-fold increase from current levels.

In developing countries a bus travels on average about 40 000 km per year, while in the OECD buses travel on average 60 000 km per year (Table 3.10). These distances should be compared with those of passenger vehicles, which range from just 8 000 km in India to 17 600 km in the United States. This higher load factor for a bus allows the investment cost to be spread over more kilometres sooner, which results in more favourable conditions for high-efficiency capital-intensive options such as FCVs.

Table 3.11 shows the annual operating cost for different buses, assuming 60 000 km per year, an annuity of 12% and O&M costs of 4% of the investment cost. Fuel taxes are included, so that the estimation represents the perspective of the bus owner. However, any external costs over and above fuel taxes due to CO_2 emissions and other local pollutants are not taken into account. An analysis for Belgium based on European Union Externe data suggests that the external effects could add USD 0.06/km (Panis *et al.*, 2004), corresponding to a total external cost of USD 3 600 a year. However, better filtres, catalysts, and improved fuels may reduce these costs substantially. Note that the fuel efficiency gains of fuel cells in Table 3.11 are much higher than the DaimlerChrysler projections (50% vs. 20%). This is an issue that requires more analysis.

At this point, conventional diesel vehicles are by far the cheapest option, even if alternative engine systems result in negligible or no external costs. Diesel hybrids are closest in terms of economics, and future cost reductions may make this the reference technology to which hydrogen FCBs should be compared. Therefore, further cost reductions are needed if advanced power solutions for buses are to become competitive. The data suggest that FCBs would become cost-effective if their additional cost is around USD 100 000. Assuming USD 50 000 for the fuel storage system and the electric engine, that leaves USD 200/kW for the fuel cells. This cost level is significantly higher than what will be necessary for fuel cells to be competitive in cars (less than USD 50/kW). The bus market therefore represents a potential niche market that would allow the early introduction of PEM fuel cell vehicles and contribute to accelerating their introduction in the car market. The total fuel cell capacity that is needed is a better measure of niche market relevance than is the number of fuel cells sold. With some 0.5 million annual bus sales worldwide (WBCSD, 2004) and a FCB capacity of 3 to 4 times the capacity of a fuel cell car, the potential fuel cell market for FCBs would be equivalent to that of some 2 million cars a year. This would be a sufficiently large market to achieve cost reductions through technology learning. It should be noted that, depending on the rate of cost reduction, a hydrogen-hybrid FCB might be more attractive than the "simple" hydrogen FCB, as it needs less fuel cell capacity. However, this depends on future fuel cell costs.

Table 3.10

Average annual vehicle mileage (by vehicle type)

	LDV (km/yr)	Heavy Trucks (km/yr)	Buses (km/yr)
OECD North America	17 600	60 000	60 000
OECD Europe	12 500	60 000	60 000
OECD Pacific	10 000	60 000	60 000
FSU	13 000	50 000	40 000
Eastern Europe	11 000	50 000	40 000
China	10 000	50 000	40 000
Other Asia	10 000	50 000	40 000
India	8 000	50 000	40 000
Middle East	13 000	50 000	40 000
Latin America	12 000	50 000	40 000
Africa	10 000	50 000	40 000

Source: WBCSD, 2004.
Note: LDV = light duty vehicles.

Table 3.11

Annual operating costs for eight bus drive-systems (includes European fuel taxes)

	Fuel use	Fuel Price	Annual fuel cost	Additional investment	Total cost
	$GJ/10^3km$	USD/GJ	USD/yr	USD	USD/yr
Diesel	19.2	30	34 644	0	34 644
Diesel hybrid	14.1	30	25 406	115 000	43 806
CNG	25.7	30	46 192	50 000	54 192
CNG hybrid	21.7	30	39 086	165 000	65 486
Gasoline hybrid	16.3	30	29 314	100 000	45 314
H_2 hybrid ICE	12.1	35	25 406	175 000	53 406
H_2 FC	10.6	35	22 230	500 000	102 230
H_2 hybrid FC	8.5	35	17 784	460 000	91 384

Source: Mazaika and Scott, 2003.

Delivery vans

DaimlerChrysler has developed a fuel cell-powered "Sprinter" delivery van, which has been operating in Germany since 2001. In 2004, fuel cell "Sprinter" vans were operated in the United States (in the states of Michigan and California) by the delivery company UPS for a full range of normal delivery services (EPA, 2004). The 55 kW electric motor allows a top speed of 120 km/h and an operating range of 150 km. UPS has long-term plans to use FCVs (Cropper, 2004). In Japan, a General Motors HydroGen3 FCV has been delivering packages for the FedEX company since July 2003.

With frequent stops and high annual mileage (20 000 to 32 000 km a year or twice the distance of regular passenger cars), a delivery service is well suited to exploit the energy-saving potential of fuel cells and obtain a more rapid recovery of the higher investment cost. In this market segment, FCVs would become cost-effective at an incremental cost of around USD 15 000 per vehicle. Assuming a 75 kW fuel cell system and USD 5 000 for hydrogen storage and the electric engine, the resulting competitiveness threshold for fuel cells would be USD 135/kW (given European fuel tax levels). The global stock of these medium duty trucks amounts to 26 million (WBCSD, 2004) and is projected to increase four-fold by 2050. Annual sales equal about 2.5 million vehicles, a market volume large enough to allow for fuel cell cost reductions through technology learning.

Wheelchairs and carts

Electric wheelchairs for handicapped persons and electric carts for aged-persons could be an important market niche. Comfort and practicality is more important than cost. For example, they are paid for by long-term care insurance in Japan. In Japan, 7 000 electric wheelchairs and 29 000 electric carts were sold in fiscal year 2004. The demand for electric carts for aged-persons is projected to increase rapidly. Worldwide demand is about ten times higher than in Japan.

Both electric wheelchairs and electric carts generally use 12V lead-acid batteries connected in series as a power source. The battery is available for about USD 500. In the case of electric wheelchairs, a 200 W output suffices for driving on flat paths, but about 1 to 1.5 kW output is necessary for driving up a slope. Kurimoto Ltd. of Japan has developed electric wheelchairs and electric carts equipped with a 250 W PEMFC and hybrid system operating on a rechargeable battery. Fuel cell wheelchairs offer the potential advantage of about twice the driving distance over existing battery systems. They also offer the advantage of being able to be driven immediately after refuelling without worrying about the charging time, which is substantial for the existing batteries. Cost reductions for the fuel cell systems and development of an appropriate refuelling infrastructure for these vehicles pose important challenges.

Forklifts

Global sales of electric forklifts amount to 300 000 units per year (FCell Canada, 2004). In southern California, in the peak period of the late afternoon, almost 2% of total power capacity is used for electric forklifts, golf carts, etc. (Cromie, 2004). Global sales of around 300 000 units per year equal 100 000-150 000 car equivalents per year. An electric forklift working three shifts a day typically comes with three lead-acid batteries - one that's in use, one that's charging and one that's cooling. Battery removal and charging is a time-consuming process that affects productivity and costs. In addition, machines become sluggish as the battery charge declines. A 65 kW battery pack for a class 1 forklift costs about USD 4 000 or about USD 60/kW. With an additional cost of about USD 3 000, a fuel cell system would offer higher productivity and no re-charging needs. For intensely used forklits, the break-even fuel cell cost would be in the order of USD 100/kW. However, this could be a relatively small part of the market, as most forklifts are not operated intensely and overnight charging is usually sufficient with no substantial drawbacks.

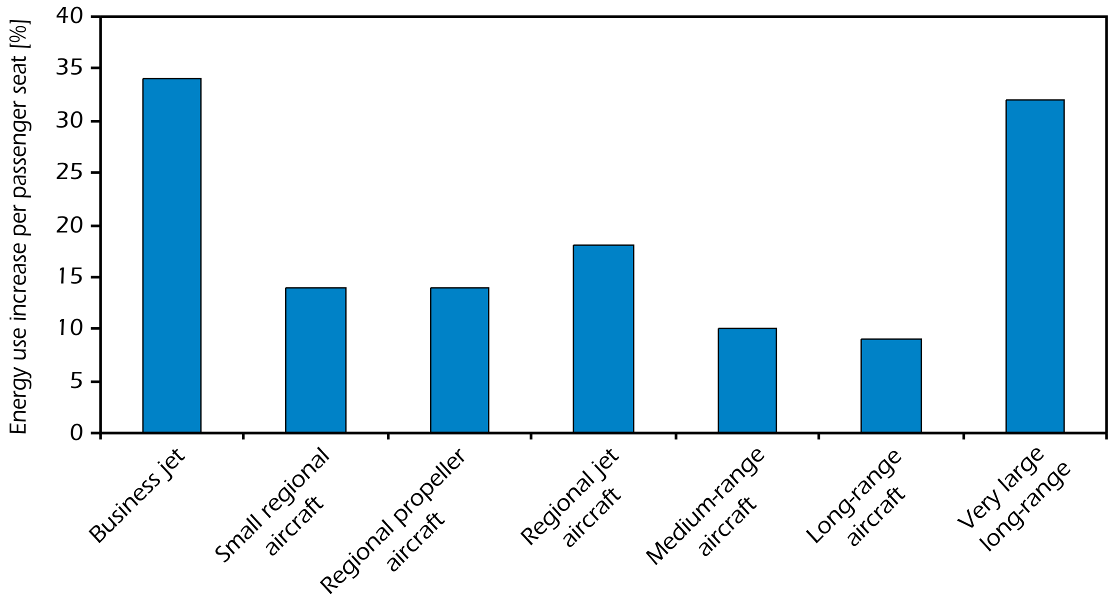
Hydrogen-fuelled airplanes

Prototype airplanes fuelled by hydrogen have been successfully demonstrated. Given the importance of weight for airplanes, liquid hydrogen is used in order to reduce the volume and weight of the storage tanks. However, the volume occupied by liquid hydrogen is four times greater than that of kerosene. The hydrogen-fuelled engine will be as efficient as the kerosene engine, but the larger wetted-surface of hydrogen storage tanks would result in higher energy consumption of between 9% and 34% (Figure 3.14). The payload of the airplanes would be 20-30% lower, but the impact on the number of passengers is less significant.

Table 3.12 presents an assessment of the costs of switching from kerosene to hydrogen for the new A-380 Airbus. The plane has a price of USD 280 million, will carry up to 665 passengers and fly 7 million kilometers per year (85% flying time and 950 km/h cruising speed). It is assumed that the hydrogen-fuelled plane carries 15% fewer passengers than the conventional plane and uses just 20% more fuel, which is a rather optimistic assumption. While the kerosene price is about USD 5/GJ, the liquid hydrogen costs are set at USD 20/GJ. With these assumptions, the switch from kerosene to hydrogen results in an emission reduction cost of USD 206/t of CO_2, making hydrogen airplanes a costly option to reduce CO_2 emissions.

Figure 3.14

The incremental energy consumption of H_2-fuelled airplanes



Source: Airbus, 2003.

Key point: The energy use per unit of service of hydrogen airplanes is 9-34% higher than for kerosene-fuelled airplanes

Both water and NOx emissions have a greenhouse impact, which depends on the cruising altitude (see Figure 3.15 and Annex 3). It is assumed that kerosene-fuelled planes can fly at altitudes of between 10 km and 11 km, while hydrogen-fuelled planes will only be able to fly at an altitude of 10 km, because the impact of water vapor increases exponentially above this altitude. The higher the airplane flies, the lower the air resistance and hence fuel consumption. Flying at 11 km requires 15% less fuel than flying at an altitude of 10 km (Figure 3.15). The option of flying hydrogen-fuelled airplanes, so-called cryoplanes, at 9 km or lower has not been considered, it increases fuel consumption despite some non-CO_2 benefits.

Table 3.12

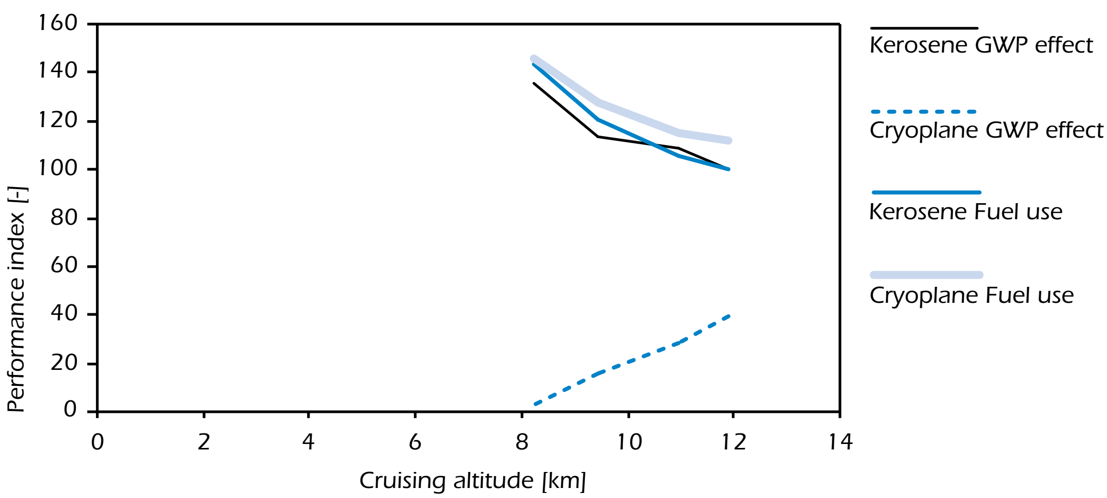
Cost assessment for a very large hydrogen-fuelled airplane

	Assumptions/notes	Unit	Cost
Kerosene plane			
Investment cost per seat	USD 280 m per plane, 665 seats	(USD 1000/seat)	420
Cost per seat occupied	75% load factor	(USD 1000/seat)	560
Investment cost per passenger.km		(USD/1000 pkm)	80
Kerosene per occupied seat per year	75% load factor, 1.6 MJ/passenger.km, 950 km/h cruising speed	(GJ/seat/yr)	10 000
Fuel + capital per seat occupied	12% annuity of cost per seat and USD 5/GJ kerosene	(USD/seat)	50 000
CO_2 emissions for kerosene	0.073 t of CO_2/GJ kerosene	(t/used seat/yr)	730
Hydrogen plane			
Cost per seat occupied	75% load factor, but 15% fewer passengers	(USD 1000/seat)	690
Investment cost per passenger.km		(USD/1000 pkm)	99
Fuel + capital per seat occupied	12% annuity, 20% increase in fuel use per seat and USD 20/GJ liq. hydrogen	(USD/seat)	200 000
CO_2 emission mitigation cost	H_2O and NO_x not considered	(USD/t of CO_2)	206

Source: Lee *et al.*, 2001.

Figure 3.15

Comparison of the fuel use and greenhouse emissions of kerosene and H_2 airplanes



Source: Svensson *et al.*, 2004.
Note: GWP = global warming potential in terms of CO_2.

Key point: *A hydrogen airplane has lower emissions at all flight altitudes*

In the model analysis, significant fuel efficiency gains have been assumed over time (Table 3.13). The investment cost for a kerosene airplane is set at USD 80 for 1 000 passenger kilometres per year. The cost of a competing hydrogen plane has been set at USD 100 for 1 000 passenger kilometres per year. Kerosene from Fischer-Tropsch synthesis using biomass as a feedstock has been considered as an alternative CO_2–free fuel without the additional costs associated with a hydrogen-powered airplane.

Table 3.13

The fuel efficiency and GHG emissions of new planes, 2000-2050

New plane fuel efficiency	*2000*	*2030*	*2050*
Kerosene at 10 km cruising altitude (1 000 pkm/GJ)	0.45	0.53	0.53
Kerosene at 11 km cruising altitude (1 000 pkm/GJ)	0.53	0.62	0.62
New cryoplane at 10 km cruising altitude (1 000 pkm/GJ)	0.38	0.44	0.44
CO_2 emissions coefficients	***2000***	***2030***	***2050***
Kerosene at 10 km cruising altitude (kg CO_2 equiv./1 000 pkm)	157	136	136
Kerosene at 11 km cruising altitude (kg CO_2 equiv./1 000 pkm)	134	115	115
New cryoplane at 10 km cruising altitude (kg CO_2 equiv./1 000 pkm)	0	0	0
Non-CO_2 GHG emissions coefficients	***2000***	***2030***	***2050***
Kerosene at 10 km cruising altitude (kg CO_2 equiv./1 000 pkm)	60	50	50
Kerosene at 11 km cruising altitude (kg CO_2 equiv./1 000 pkm)	120	105	105
New cryoplane at 10 km cruising altitude (kg CO_2 equiv./1 000 pkm)	7	3	3

Source: IPCC, 2000 ; Svensson *et al.*, 2004; WBCSD, 2004.

Prospects and applications for stationary fuel cells and other hydrogen uses

Stationary fuel cells (most likely PEMFCs, MCFCs and SOFCs) can be used for the distributed and centralised production of electricity. If the waste heat generated is used in a combined heat and power system, the overall system efficiency can exceed 90%. Stationary fuel cells do not necessarily need to use hydrogen as a fuel, as MCFCs must use non-hydrogen fuels (natural gas or other hydrocarbons). 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. SOFCs and MCFCs seem better suited to residential CHP applications, because they do not need a separate reformer, although PEM fuel cells may also be used for stationary applications.

In terms of electrical and total efficiency, the differences between MCFCs and SOFCs are small. SOFCs are slightly more efficient, but MCFCs currently seem better suited to large-scale plants. The durability of the fuel cell is also critical to the final electricity cost of generation from fuel cells. The lifetime of small-scale residential SOFC systems is currently only around 4 500 hours (Sulzer Hexis, 2004). However, a 100 kW unit produced by Siemens-Westinghouse operated for more than 20 000 hours. At the moment, the research goal is for stationary applications to have a lifetime of 40 000 to 60 000 hours, or 5-8 years of operation. The lifetime depends very much on the operating conditions. Increasing the average life of fuel cells will be imperative to reducing the cost of electricity generated. Improved fuel cell design, as well as new high-temperature materials could considerably enhance the durability of these fuel cells. The auxiliary equipment needed for the fuel cell stack also determines the life of the fuel cell system.

Molten carbonate fuel cells

Molten carbonate fuel cells use a molten-carbonate-salt electrolyte suspended in a porous, inert ceramic matrix. They cannot be fuelled by pure hydrogen, because they need CO_2 to generate CO_3^{2-} ions that are transferred from the cathode to the anode. They operate at temperatures higher than 650 °C and no precious metal catalyst is required, which considerably reduces their cost. Also, given their higher operating temperatures, no external reformer is needed. MCFCs can achieve efficiencies of 60% and up to 90% if used for cogeneration. Their resistance to poisoning and their lifetime are being improved. Their operating life is adversely affected by their high operating temperature and electrolyte-induced corrosion.

FuelCell Energy and MTU (a DaimlerChrysler subsidiary) are among the major companies involved in MCFC development. At full load, the "MTU Hot module" MCFC system achieves a 55% stack efficiency and 47% electrical efficiency in AC current terms (MTU, 2004). The off-gas temperature is around 400 °C and the efficiency in cogeneration mode can be up to 90%. At partial loads the electrical efficiency will be considerably lower. The MTU system has an electrical capacity of around 250 kW. If a gas turbine is integrated into the design, the electric efficiency can be raised to 60%. In 2003, the system cost USD 13 000/kW (Hoogers, 2003). Table 3.14 indicates that the current investment costs for stationary fuel cells are high compared with USD 500/kW for a conventional large-scale gas-fired combined-cycle power plant. The MCFC system cost should be able to be reduced to a target cost of about USD 1 650/kW with mass-production. The stack cost represents half of the current investment cost. The incremental cost of fuel cells should be weighed against the increased energy efficiency relative to other distributed generation options. If the size of the MCFC can be increased from 200 kW to 2 MW, the cost should decline by about 26% (Blesl *et al.*, 2004).

The net efficiency of a 100 kW MCFC system is 42% for DC generation at the LHV (Table 3.15). The main losses are due to the gas compressor and the blowers. A significant efficiency increase can be achieved if the off-gas is used in a gas turbine. The gain could be five percentage points for a 300 kW system and about nine percentage points for a 20 MW system (Watanabe, 2003). A small-scale MCFC-GT system can achieve 47% net electrical efficiency, while a large-scale system may achieve up to 53%. However, the cost for these systems will be higher than those listed in Table 3.14.

Table 3.14

Cost comparison of MCFCs and SOFCs

	MCFC (300 kW)			SOFC (200 kW)	
	Demo (USD/kW)	Market Introduction (USD/kW)	Target (USD/kW)	Demo (USD/kW)	Target (USD/kW)
Operating system	1 148	722	167	1 723	145
Inverter	123	119	97	211	92
Heat exchanger	400	277	84	383	92
Reformer	761	493	62	73	73
Boiler	3 005	1 984	436	6 541	535
Burner	361	233	66	152	53
Stack	6 525	4 400	585	6 600	554
Frame	700	524	141	0	59
Air supply	44	35	13	165	53
Total cost	13 068	8 787	1 650	15 847	1 657

Source: Blesl *et al.*, 2004.

Table 3.15

Efficiency balance of a 100 kW MCFC system (DC electricity and no turbine)

Natural gas fuel	(kWth, LHV)	206.8
Delivered power MCFC stack	(kWel)	100.0
Auxiliary power consumption		
NG compressor	(kWel)	–3.4
Anode blower	(kWel)	–4.4
Cathode blower	(kWel)	–2.2
Total	(kWel)	–13.0
Delivered net power	(kWel)	87.0
Gross efficiency	(% LHV)	48.4
Net efficiency	(% LHV)	42.1

Source: Kang *et al.*, 2002.

Solid oxide fuel cells

Solid oxide fuel cells use a non-porous ceramic electrolyte and appear to be the most promising fuel cell technology to generate electricity. When combined with a gas turbine, SOFCs are expected to be able to achieve up to 60-70% electrical efficiency and an overall efficiency of up to 80-85% for cogeneration. High operating temperatures (800-1 000 °C) mean expensive catalysts and external reformers are unnecessary, helping to reduce the fuel cell cost. In addition to hydrogen, SOFCs can use carbon monoxide as fuel. The R&D goal is to enhance the sulphur tolerance of SOFCs, so that they can be fuelled by gas derived from coal. A short life and long start-up times are the main drawbacks of the high operating temperature. Similar to that of other fuel cells, the development of low-cost materials with high durability remains the key technical challenge for this technology.

The current cost of an SOFC pilot plant is around USD 12 000/kW (Blesl *et al.*, 2004). The goal is to reduce the cost to around USD 1 300-2 500/kW. An overview of current and past tests by Siemens-Westinghouse, one of the leading SOFC suppliers, is provided in Table 3.16. The size of the systems has gradually increased over the past 20 years and Siemens-Westinghouse's first pre-commercial product will be the SFC-200. This is a 125 kW SOFC cogeneration system operating on natural gas at atmospheric pressure and with an electrical efficiency of 44-47%. An overall system efficiency of greater than 80% is expected for cogeneration. The SFC-200 will be the building block for systems up to 500 kW.

There are two basic configurations for SOFCs: the tubular and the planar stack assembly. The tubular design was developed by Siemens-Westinghouse and Mitsubishi Heavy Industries. Its advantage is that it does not require any gas seals between individual cells and that the tubular shape can handle the thermal expansion of the cells. Current systems are sold in bundles of 24 tubes of 2.2 cm diameter and 1.5 m length, with a theoretical output of 200 W and a 120 W practical output (including DC/AC conversion losses). The main drawbacks and challenges for these systems are the lack of chemical stability of this approach, the need to make the porous electrodes more dense, and the start-up time of several hours (Vora, 2005).

The planar configuration is being pursued by Mitsubishi Heavy Industries, Honeywell, General Electric, Sulzer Hexis and Siemens-Westinghouse. A planar geometry allows a higher current density, better performance and easier manufacturing than the tubular geometry. Mitsubishi has successfully tested 10 kW planar stacks, and 50 kW systems are currently under development (Yoshida *et al.*, 2003). In 2002, under the US-DOE Solid State Energy Conversion Alliance (SECA), Siemens-Westinghouse signed a co-operative agreement with the DOE National Energy Technology Labs to test low-cost 3-10 kW SOFCs for residential, automotive and military applications. New, cheaper materials are being used to develop low-temperature SOFCs working at 600-700 °C which use an external reformer to convert the natural gas. However, this technology is still at the laboratory stage.

Table 3.16

SOFC tests by Siemens-Westinghouse

Year	Stack rating (kWe)	Cell length (mm)	No. of cells/stack	Operation (hours)	Fuel
1986	0.4	300	24	1 760	H_2+CO
1987	3	360	144	3 012	H2+CO
1987	3	360	144	3 683	H_2+CO
1987	3	360	144	4 882	H_2+CO
1992	20	500	576	817	PNG
1992	20	500	576	2 601	PNG
1992	20	500	576	1 579	PNG
1993	20	500	576	7 064	PNG
1994	20	500	576	6 015	PNG
1995	25	500	576	13 194	PNG
1998	27	500	576	3 394+	PNG
1997	125	1 500	1 152	4 035	PNG
1999	125	1 500	1 152	12 577	PNG
2000	180	1 500	1 152	3 257	PNG
2001	125	1 500	1 152	3 872	PNG
2002	250	1 500	2 304	1 000+	PNG
2005	125	1 500	1 128		PNG
2006	125	1 500	1 128		PNG

Source: Siemens-Westinghouse, 2005.
Note: PNG = pressurised natural gas.

Table 3.17 presents the energy balance for a SOFC power plant, tailored to city district heating and maximised for electricity production. Gross and net electrical plant efficiency is 62.5% and 44%, respectively. The difference is accounted for by air compression, oxygen production and various pumps and blowers. Note that a 44% electrical efficiency is not better than the efficiency that can be achieved with current coal-fired super-critical power plants.

SOFC systems could be easily integrated into district heating systems. Like MCFCs, SOFCs with gas turbines have higher efficiencies than the simple configuration. The world's first hybrid SOFC gas-turbine (SOFC-GT) system was delivered to Southern California Edison. The system had a design output of 220 kW, with 200 kW from the SOFC and 20 kW from a micro-turbine generator. It operated for nearly 3 400 hours and achieved an electrical efficiency of about 53%. This is the highest known electrical efficiency achieved by any commercial-scale fuel cell system. In theory, such SOFC-GT systems could be capable of electrical efficiencies up to 60-70% (Siemens-Westinghouse, 2005).

Table 3.17

Energy balance of a coal-fired SOFC power plant

Thermal input	(MWth, LHV)	50.00
Fuel cell	(MWel)	17.62
Steam turbine	(MWel)	3.63
Anode expander	(MWel)	0.00
Post-fuel cell expander	(MWel)	10.01
FC air compressor	(MWel)	–6.80
Hot gas quench blower	(MWel)	–0.12
Sulphur recovery blowers	(MWel)	–0.89
Pumps	(MWel)	–0.07
Oxygen production	(MWel)	–1.36
Gross power	(MWel)	31.26
Net power	(MWel)	22.02
District heat	(MWth)	19.04
Gross electric efficiency	(% LHV)	62.5
Net electric efficiency	(% LHV)	44.0

Source: Kivisaari *et al.*, 2004).
Note: The calculations are for DC electricity production and the gasifier efficiency is assumed to be 85%.

A number of producers are focusing on SOFCs for the residential market. For example, Sulzer Hexis is focussing on small-scale SOFC systems using natural gas for residential cogeneration (Table 3.18), and over 100 such SOFC systems have been installed so far (Diethelm, 2004). The latest designs achieve an electric efficiency of 30% and have a life of more than one year. Their average efficiency is considerably lower than what would be the full-load efficiency (TIAX, 2002). For comparison purposes, the efficiency of existing condensing gas boilers is 107%.[14] A typical system for a single family house would need an electrical capacity of 1-4 kW. The capacity would be tailored to meet the base heat load or the average demand. This means that during peak-demand periods, external electricity supplies or batteries are needed (TIAX, 2002). In cogeneration, a typical heat-to-electricity ratio is four.

Table 3.18

Characteristics of residential fuel cell CHP systems

Producer	Electric (kWel)	Thermal (kWth)	Characteristics	Status
VAILLANT	5	1.7-7	Plug power stack, extra burner 25-280 kWth	Announced for 2010
BAXI/European Fuel Cells	1.5		Additional burner	Field trials shortly, announced for 2009-2012
Sulzer Hexis	1		SOFC, extra burner, hot water tank	>100 field trial units, announced for 2005-2006 1000-10 000 units/year
CFCL	1		SOFC, extra burner	Demonstration 2005, announced for 2007

Source: Wilcox, 2004.

14. On a Lower Heating Value basis, which equals less than 100% on a Higher Heating Value basis.

Table 3.19 presents the cost of SOFC systems fuelled by natural gas and heating oil, assuming annual production of 500 000 units. The cost ranges from EUR 725/kW to EUR 1 900/kW, depending on the system size and the fuel choice.

Table 3.19

The cost of residential SOFC systems (assuming 500 000 units/year)

SOFC	1 kW	2 kW	4 kW
Natural gas (EUR/kW)	1 400	950	725
Heating oil (EUR/kW)	1 900	1 200	850
Maintenance (EUR/kW.yr)	200	150	125
Maintenance (EUR/GJ.yr)	18	14	11

Source: Erdmann, 2003.

Table 3.20 compares the characteristics of two CHP systems, an SOFC system and a conventional ICE system, for an apartment building requiring a capacity of 200 kWel. SOFCs are currently much more expensive, but the investment cost for an SOFC CHP system may come down to the the level of a conventional system by 2030. The electrical efficiency of SOFCs is much higher, but the overall efficiency is the same. The efficiency quoted for fuel cell systems refers to DC electricity; the conversion to AC results in substantial losses. The system efficiency may be up to 93% at peak load, but will drop below 80% if the load drops below 20% (TIAX, 2002).

Table 3.20

Comparison of conventional and fuel cell CHP systems

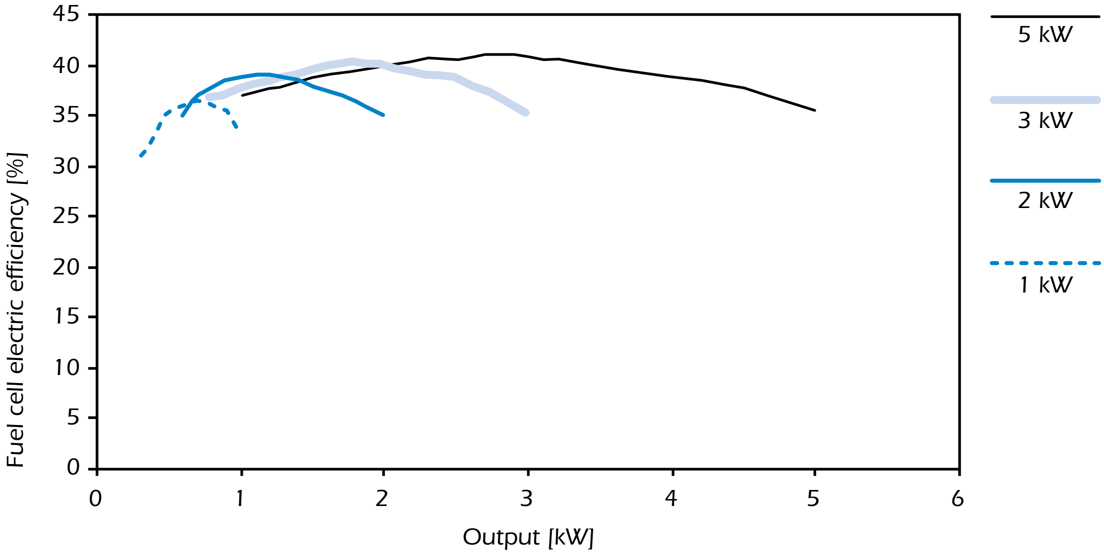
	Conventional CHP	SOFC CHP 2010	SOFC CHP 2030
Specific investment cost (EUR/kW)	1 000	5 000	1 000
Electrical power (kWel)	200	200	200
Thermal power (kWth)	326	244	164
Electricity bonus (USc/kWh)	2.0	5.0	5.0
Electrical efficiency (%)	38	45	55
Overall efficiency, electric + heat (%)	90	85	90
Cost share of stack in total investment (%)	–	1st stack 30%	1st stack 25%
Stack life (h)		40 000	70 000
Operating time (h/yr)	5 000	5 000	5 000
Maintenance (EUR/kWh)	1.5	2.5	0.5

Source: Lokurlu *et al.*, 2003.
Note : Electricity bonus reflects the new German CHP plant modernisation law and does not apply to other countries.

The efficiency of SOFC systems when operating is a function of the load, while larger systems tend to have higher efficiencies (Figure 3.16). There is therefore a trade-off between electricity production and efficiency for a given system. The electrical efficiency at peak capacity is 2 to 5 percentage points lower than at partial load. The efficiency of the overall system also depends on the efficiency of the power electronics. In the case of a 4 kW stand-alone system for a single-family dwelling, assuming an average power electronics efficiency of 90% and an average fuel cell efficiency of 38%, the net efficiency of the system is only 34%. Cogeneration can increase the overall net efficiency, but the different seasonal demands for heat and electricity in many regions of the world limit the potential for this to be optimised. Therefore, prospects for small-scale, stand-alone systems are not optimistic except for remote regions (Swisher, 2002). These market niches are not analysed in more detail in this study.

Figure 3.16

Electric efficiency of residential SOFC systems



Key point: *The efficiency ranges from 31% to 41% depending on the load and the system size*

Modelling stationary fuel cells

Stationary, grid-connected fuel cells for residential and commercial sector CHP applications are included in the ETP model analysis. They are split into single-family dwellings, multi-family dwellings and commercial sector buildings. Two types of SOFC systems are modelled for single family dwellings: a 1 kW and a 4 kW system. Three types of fuel are considered: natural gas, fuel oil and hydrogen. PEM fuel cells using only hydrogen are also included. SOFCs or MCFCs are the preferred technology for fossil fuels, as they do not need an external reformer, but SOFCs can also use hydrogen. Hydrogen fuel cells represent the only type of fuel cell with zero CO_2 emissions. The characteristics of SOFCs and MCFCs are so similar that it does not make sense to model them separately.

Critical to the economics is the modelling of the heat demand of a household. Heat demand is split into hot water and space heating. In IEA countries, space heating accounts for 55% of residential energy use, while water heating accounts for 19% (IEA 2004d). This ratio depends on climate, the level of building insulation and the size of the house. In Germany, France and the United Kingdom, annual energy use for heating is 30-35 GJ/per capita, while in the United States and Canada, it is about 40-45 GJ per year. In contrast, in Japan and Australia, it is less than 20 GJ per capita per year (IEA 2004d). Heating energy demand in many developing countries is considerably lower than in the IEA countries due to the very different climate conditions.

Fuel cells for apartment blocks have to be modelled separately. Hot water demand is almost constant during the year, while heating demand is seasonal. As the fuel cells operate continuously during the year, they are more suited to meet hot water demand than heating demand. While more than 25% of the heat produced by a fuel cell can be used to heat water, the useful heat that can be used is, in practice, well below the heat production potential of a fuel cell. The efficiencies of fuel cells have been corrected to take into account the effect of the power electronics efficiency. These are set at between 90% and 95% for systems greater than 1 kW. The electrical efficiencies of fuel cells (excluding losses in the power electronics) are assumed to be 40% and 42% for 1 kW and 4 kW SOFC systems respectively. Larger 100 kW SOFC systems are assumed to have efficiencies ranging from 45% to 55%, or 35% to 40% for PEM fuel cells.

For industrial applications, a SOFC power plant in combination with a combustion turbine (SOFC pressurised hybrid) can achieve efficiencies of 60-65%. A SOFC pressurised hybrid system of several MW with active after-burner and CO_2 capture could eventually achieve 70% net efficiency (Heidug, Haines and Li, 2000). This value is 5-10% higher than the potential efficiency of combined-cycle gas-turbines. The efficiencies assumed here are for SOFCs fuelled by natural gas. If coal is used, the gasifier efficiency (about 85%) must be taken into account. The gasifier would also contribute to the system cost, adding about USD 1 000/kW. SOFCs for centralised power plants will require a factor 10-100 up-scaling over current fuel cell systems to be economic.

Other stationary applications for hydrogen

Adding hydrogen to the natural gas distribution system

In principle, hydrogen could be used in all types of equipment than can use natural gas. Hydrogen could therefore be mixed with natural gas and distributed through the existing natural gas pipeline network. While small additions could be easily accommodated from a technical point of view, more substantial additions would require modifications to the burners and controls in many types of consumer equipment. Up to 3% hydrogen by volume can be added to natural gas (*i.e.* 1% in energy terms) without any changes to devices being needed. Up to 12% (4% in energy terms) can be used without modifications in all devices included in the 1998 EU standards (no data are available for other regions). Pipeline systems could handle the addition of up to 25% (9% in energy terms) of hydrogen by volume, but this would require new end-use devices (Haines *et al.*, 2004). The model includes an option for the addition of hydrogen to pipelines at the level of 10% in energy terms for all end-use sectors (residential, commercial and industry). The additional investment cost is assumed to be USD 2.5/GJ of delivered gas mixture, based on annual costs of between USD 23/GJ and USD 33/GJ of hydrogen (Table 3.21).

Table 3.21

The cost of adding 9% (in energy terms) hydrogen to natural gas systems

	Netherlands (USD/GJ.yr)	UK (USD/GJ.yr)	France (USD/GJ.yr)
Gas chromatographs	0.02	0.01	0.01
Gas engines	1.15	0.09	0.00
LP control adjustment	0.02	0.00	0.00
MP control adjustment	0.05	0.02	0.07
HP control adjustment	0.00	0.00	0.00
Medium pressure transmission upgrade	19.03	13.20	21.52
Domestic appliances: check for light-back	6.60	7.26	8.71
Domestic appliances: conversion	2.38	2.62	3.14
Natural gas vehicles	low	low	low
Natural gas refuelling stations	low	low	low
Gas turbines	regular maintenance	regular maintenance	regular maintenance
Total cost	29.25	23.20	33.45

Source: Haines *et al.* 2004.
Note: LP = low pressure, MP = medium pressure and HP = high pressure.

A special problem is that variations in the consumption of gas over the year would lead to variations in the composition of the gas mixture if the supply of hydrogen is constant over the year, a likely pre-condition for the economic production of hydrogen. Alternatively, either the load factor for the hydrogen supply systems would need to be lower, raising the cost of the hydrogen, or hydrogen gas storage would be needed. For the time being, no large-scale seasonal hydrogen storage is accounted for in the model. Therefore, the cost assumptions are optimistic. In any event, this option will only be selected in the case of ambitious CO_2 policies, because the additional investment cost of USD 25/GJ translates into an abatement cost of more than USD 50/t of CO_2 avoided, provided the H_2 supply is CO_2-free and the price is similar to the natural gas price.

Hydrogen use in industry

Hydrogen can be used by all types of burners where natural gas is used, provided that proper adjustments are made. Hydrogen could be used for steam generation in natural gas-fired boilers or combined heat and power units, but its main advantages are exploited when hydrogen is used in fuel cells. Hydrogen fuel cells for industrial CHP applications and hydrogen-fuelled burners are technology options used in the ETP model. Also, hydrogen can be used for specific production processes, such as the production of direct reduced iron (DRI). At the moment, natural gas is the main fuel for this type of process, but the combined use of electric arc furnaces and hydrogen in the DRI process would eliminate the CO_2 emissions from primary steel production. This option has been considered in the ETP model.

Hydrogen use in the power generation sector

As discussed in Chapter 2, hydrogen is a key intermediate step in CO_2 capture and storage if pre-combustion CO_2 removal is to be undertaken at centralised fossil-fuel power plants. In these plants, fuelled in general by coal, hydrogen is a by-product emerging from the de-carbonisation process. It is then burnt in a gas mixture to produce electricity. Such plants offer important advantages and the economies of scale necessary for the large-scale production of hydrogen without emissions. They also offer significant flexibility for the combined production of hydrogen and electricity. In contrast, distributed electricity production from hydrogen only makes sense if the hydrogen used is produced from intermittent electricity production (*i.e.* the hydrogen is produced to be an energy storage medium), or if it is to avoid CO_2 emissions from small-scale cogeneration units.

Another application is the use of PEMFC vehicles for distributed power generation. This option is discussed in the Annex 5. Although potential technology breakthroughs could make this option attractive, the IEA analysis suggests that currently this option faces too many unresolved issues of a critical nature. Therefore, it has not been considered in the model analysis. Having said this, an interesting concept could result in significant synergies based on the development of PEMFC systems for both stationary and mobile applications, as well as PEM electrolysers. An annual production of 0.5 million FCVs (a large-scale plant) would require the production of 80 GW of PEM fuel cells. If current estimates for stationary fuel cells are extrapolated to 2030, 25 GW of stationary FCV capacity might be feasible. In addition, if 1% of global refuelling stations are converted into hydrogen refuelling stations each year (with a capacity of 300 cars/day, necessitating 2 MW of electrolyser), 136 GW of refuelling capacity would be built per year. When these three markets are combined, a PEMFC producer who had products in all the three market segments (mobile and stationary fuel cells, and electrolysers) could double or even triple annual production, with considerable advantages in terms of economies of scale and cost reductions. Such strategies have not been considered in the analysis.

Chapter 4.
COMPETING TECHNOLOGY OPTIONS

HIGHLIGHTS

- Hydrogen and fuel cell technologies compete with many alternative fuels and technology options that can be applied to meet energy-security and environmental goals.
- In the transport sector, major competitors for hydrogen include biofuels, CNG, and Fischer-Tropsch (FT) synfuels from coal and gas. Biofuels and efficiency improvements in advanced ICEs and hybrid vehicles are attractive, low-cost options for transport in the short and medium term. Plug-in hybrids are attractive in the longer term. Hydrogen-fuelled hybrid vehicles are competing options for fuel cell vehicles (FCVs). The deployment of hydrogen FCVs faces a chicken-or-egg problem – no investment in infrastructure without substantial demand, but no significant demand without that infrastructure. Hydrogen hybrid vehicles face similar issues as FCVs for hydrogen on-board storage and the chicken-or-egg infrastructure problem, but they do not require as extensive drive-system cost reductions. Other technologies and fuel options do not face similar introduction barriers.
- For both stationary and mobile applications, competing options also are energy efficiency and large-scale electrification based on coal with CO_2 capture and storage, nuclear, or even renewable energy sources. Large-scale electrification in conjunction with plug-in hybrid vehicles and Li-ion batteries could lead to reconsideration of the role of electricity in transport.
- For stationary applications – either distributed electricity generation or cogeneration – the competition is also severe. Highly-efficient, centralised coal and gas fired power plants with CO_2 capture, emerging renewable technologies and new nuclear power plants could become strong competitors for all technologies for distributed generation including fuel cells. At the same time, new technologies such as micro-turbines and Stirling engines are being introduced for distributed heat and power production. Enhanced building insulation and industrial energy efficiency measures may also limit future heat demand. On one hand a reduced heat demand limits the potential for stationary fuel cells, but on the other hand, an increased power-to-heat demand ratio makes fuel cells more attractive compared to other CHP technologies.
- Assessing the future of hydrogen and fuel cells without taking into account competing options would result in misleading conclusions. Development risks, uncertainty surrounding each technology and the competing options must be taken into account in setting energy policies and strategies. Picking "winners" at this stage is premature.

Taking into account competing technology options and fuels is essential to assessing the real potential of hydrogen and fuel cells. Some competing technologies have already been described in Chapters 2 and 3. In this chapter, further direct competitors are discussed in more detail along with some policy issues which may affect the success of some technologies.

Competing options in the transportation sector

Biofuels

Biofuels accounted for 0.8% of total transportation sector energy use (0.6 EJ) in 2003, though this figure is likely to continue to grow in the future. World ethanol production is likely to reach 46 bn litres in 2005, 80% of which (0.78 EJ) is for fuel use. Around 40% of ethanol production takes place in the US, 40% in Brazil and 7% in Europe (FO Lichts, 2005). The production of biodiesel from rapeseed and other oil seed crops is smaller, at about 3 bn litres (0.1 EJ). Two-thirds of the world biodiesel production takes place in Europe.

Biofuel production is based on sugar cane in Brazil and on corn in the US. However, technological advances mean that the economic resource base is gradually widening to include cellulosic crops and even wood. Being able to use such low-cost feedstocks will help to increase the global production of ethanol. At present, various countries and regions are planning a rapid expansion of ethanol use. Some scenarios suggest that a ten-fold increase (to the equivalent of 4 mbd of oil products) by 2020 could be feasible, based on sugar cane ethanol alone (IEA 2004e).

This does not include the possibility of converting biomass via Fischer-Tropsch processes into liquid fuels, primarily biodiesel. The yield per hectare for this type of biodiesel would be much higher than for current oil seed crops. However, costs are higher than for FT synfuels from gas and coal because of the small plant size that is dictated by the dispersed nature of a biomass feedstock. Production costs amount to USD 90/bbl (USD 19/GJ) for a biomass feedstock price of 3 USD/GJ, with the potential to decline to USD 70-80/bbl (14-16 USD/GJ) (Hamelinck *et al.*, 2004). The high cost of production means that there are currently no plans to initiate large-scale production. This option is being investigated in Europe due to the relatively high share of diesel cars which are not able to use ethanol.

The long-term prospects of bioethanol, or any other biofuels such as methanol and biodiesel, depend on low-cost biomass availability. This availability depends on future food demand, food patterns, agricultural productivity and competition for land from other uses. Analysis that takes these factors into account suggests a cost-effective potential for "new" primary biomass ranging from 50 to 100 EJ by 2050 with emission reduction incentives of USD 80/t of CO_2 (Gielen *et al.*, 2002, 2003). This study assumes a total of 200 EJ of primary biomass could be available, including both traditional and new biomass (see Annex 1 for details). This assumes the global convergence of agricultural yields and free trade in agricultural products. Given that the biomass potential depends on uncertain agriculture productivity gains, the availability of biomass in sensitivity analysis has been reduced to 100 EJ.

Plug-in hybrids and other electric vehicles

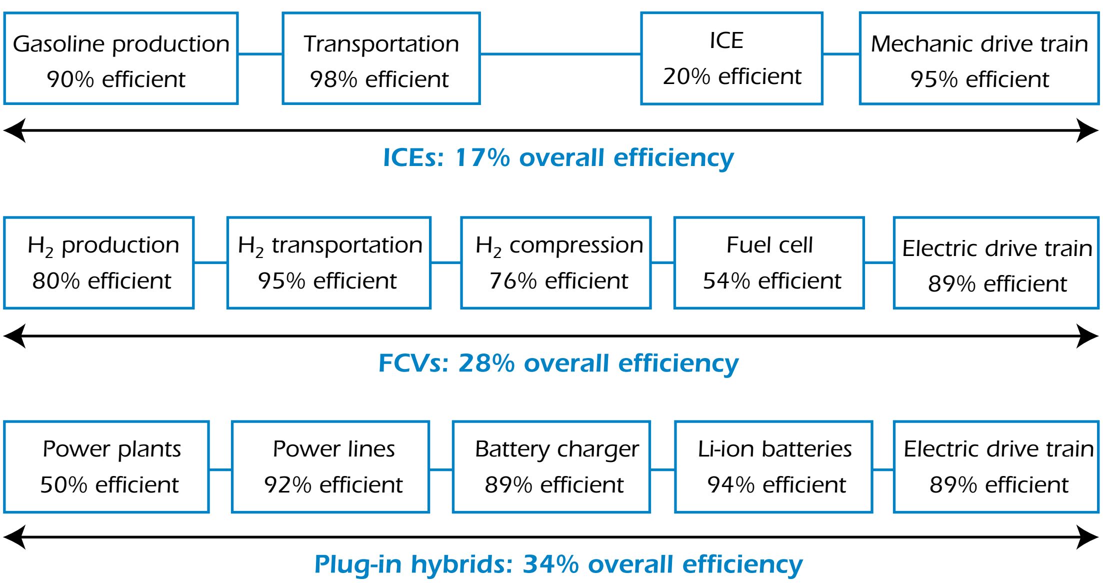
In the 1990s there was a lot of interest in electric vehicles with batteries that were charged from the grid. These vehicles were not commercially successful, because they did not have sufficient range and the weight of the batteries was prohibitive. In theory, the efficiency of such vehicles can be higher than the efficiency of hydrogen FCVs (Figure 4.1). However, electricity storage remains a key obstacle in terms of driving range and storage cost.

The interest in electric vehicles has increased in recent times because of the emergence of hybrid vehicles. If the batteries are charged from the grid only a limited range is achieved, but hybrid vehicles charge their batteries using the on-board ICE. Plug-in hybrids represent a new concept where batteries can be loaded with electricity from the grid, or through on-board electricity generation using combustion engines of fuel cells. The share of fuel and electricity use will depend on the specific drive range required, whether the driving is urban or highway, and the battery storage capacity. Assuming production volumes of 100 000 cars per year, the *incremental cost* of a plug-in hybrid electrical vehicle (HEV) with a range of 35 km would be USD 4 000-6 100, or some 21% to 32% more. For an HEV with a 100 km battery range it would be USD 7 400-10 300. For a 100 km range, the battery cost is USD 5 800, the remainder being the incremental cost for the hybrid system.[15] The cost is similar for both nickel metal hydride and lithium-ion batteries (EPRI, 2003). Lithium-ion batteries are already used for passenger cars, but their potential has not yet fully been proven. In any event, there is no potential for a cost reduction below 160 USD/kWh, unless different materials are used (ANL, 2000). This puts the minimum cost for the battery for a 100 km range at USD 3 750 at a weight of about 200 kg.

If such a system halves the fuel use of a HEV compared to a conventional ICE vehicle (350 l/yr), then the CO_2 saving is 0.8 t per year. The fuel saving can be valued at USD 700 per year including European taxes (*i.e.* for the consumer), while the cost of electricity would amount to USD 100 per year (900 kWh at USD 0.1/kWh, including 11% losses for the battery charger). At an annuity of 10%, the incremental capital cost would amount to USD 475. This configuration would have lower cost than the regular car, even at somewhat higher electricity cost than USD 0.1/kWh. If the electricity is CO_2 free, this plug-in HEV would have very low well-to-wheel CO_2 emissions. In the United States, with their lower fuel taxes, the fuel savings would be worth USD 200 per year and the emission reduction cost would be USD 200/t of CO_2. Plug-in HEV passenger cars are not yet available to the public and their performance under road conditions still needs to be tested. As a result, this option has not been considered in the model.

Figure 4.1

Well-to-wheel fuel chain efficiency of ICEs, FCVs and plug-in hybrids



Source : Bossel *et al.*, 2003; Eaves, 2003; IEA data.
Note : The efficiency of plug-in hybrids only applies if they use electricity from the grid, which implies a limited drive range.

Key point: Electric vehicles in principle have the highest fuel chain efficiency

15. *This assumes USD 270/kWh (USD 75/MJ) and USD 800 balance-of-plant cost for the battery stack.*

Lessons from hybrid and electric vehicles

The experience so far with hybrid vehicles constitutes an interesting case study for the future of fuel cell vehicles. The concept was first introduced by Toyota, with the hybrid Prius vehicle going on sale in Japan in December 1997 and subsequent record sales of 18 000 cars in that year. In 1999, Honda released the first hybrid car for the mass market in the United States. In June and September 2000, Toyota released the Toyota Prius in the United States and in Europe respectively. In 2002, Honda introduced its second hybrid gasoline-electric car. In 2004, US hybrid sales amounted to 200 000 vehicles and monthly sales increased from 4 000 in January 2004 to 17 000 in March 2005. Other car producers are either licensing Toyota's technology or developing their own hybrid technology. Some studies estimate that by 2007, ten years after the first hybrid car was introduced, about 700 000 hybrid vehicles will be sold in the United States, while annual global hybrid production could reach one million units by 2010

Despite the encouraging sales growth and the fact that United States hybrid buyers in 2004 and 2005 will benefit from a federal tax deduction of USD 2 000, sales will still amount to less than 3% of total car sales. In Europe, purchase tax deductions vary by country ranging from zero to USD 7 500 per vehicle. Despite these incentives, sales in Europe are sluggish as relatively energy efficient diesel engines maintain their large market share.

Current marketing strategies barely mention the benefits of fuel savings at the pump, or the local and global environmental benefits. Instead, hybrids are offered through "no compromise" or "guilt-free" messages. This will certainly move hybrids past the early adopters into the next layer of the mainstream. The downside is that the energy efficiency benefits might be limited. The availability of nickel-hybrid batteries is currently limiting the rate of growth in the production of hybrid vehicles (Welch and Dawson, 2005).

The lesson from the introduction of hybrids is that, even with a successful introduction, the capture of a few percent market share could take more than a decade. The question becomes what are the fundamental advantages of FCVs that a marketing strategy could use to result in FCVs capturing more than 10% of the market in the first decade after their introduction, and whether governmental subsidies via purchase tax-exemptions are the right strategy. This question deserves not only further technical and economic studies, but an analysis of the social drivers behind vehicle sales. It will also be critical that production capacity is capable of growing with demand. The availability of materials such as platinum, membrane materials, or metal hydrides for hydrogen storage could be a constraint on the market expansion of FCV and could risk the loss of valuable market momentum. Also, the fact that hybrid vehicles are selling relatively well poses a further challenge for FCV introduction, as the FCV efficiency gain over hybrid vehicles is smaller than that over ICEVs.

The case of electrical vehicles is also of particular interest. A small number of all-electric cars from the major auto-makers including Honda, GM, Ford and Toyota were introduced in California in the 1997-1999 period. Despite the enthusiasm of early adopters, the vehicles failed to reach more than a few hundred drivers for each model and in a few years the electric vehicle programmes were dropped. For the environment at least, it is to be hoped that hydrogen FCVs, the current production of which is of a similar order of magnitude, do not share the same fate.

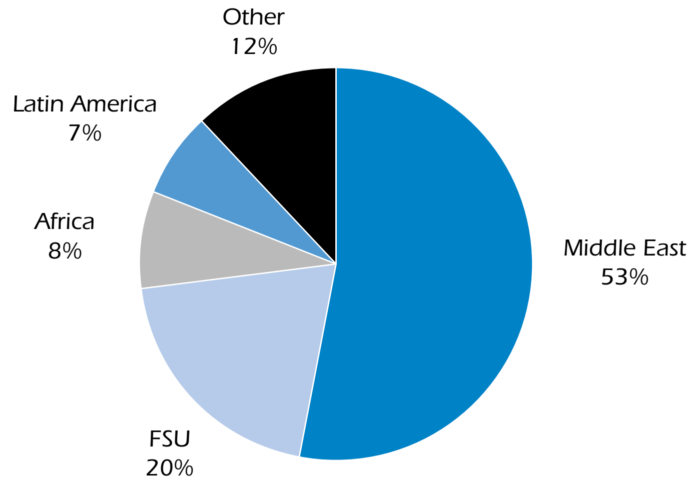
Synfuels from gas and coal

Fischer-Tropsch synthesis for production of synfuels is an established technology. Fossil fuels or biomass are converted into syngas via steam reforming, autothermal reforming or gasification. This syngas is then converted into diesel and naphtha in a catalytic Fischer-Tropsch reaction. South Africa has deployed this technology on a large-scale during the past 50 years and Sasol has been operating a 0.15 mbpd coal-to-liquids plant for about 25 years, which has recently been changed to use cheaper gas as a feedstock. The product mix consists of 80% diesel and 20% naphtha. China has expressed interest in an advanced version of the Sasol conversion process. Two 0.08 mbpd plants based on indirect conversion (first gasification, followed by FT-synthesis) are being investigated. A 20 000 bpd plant based on direct conversion (coal treatment with hydrogen) is currently operational (Coaltrans, 2003). The Chinese plans for the CTL process could add up to 1.2 mbpd of production by 2020.

FT-synthesis from natural gas is also well established and further expansion up to 1 mbpd is planned for 2010, with the bulk of this capacity being located in the Middle East (Chemical Market Reporter, 2004). The conversion efficiency is about 55%, with a theoretical maximum of about 78%. Due to the energy losses, this process only makes economic sense if cheap gas is available. As the costs for LNG transportation decline and the demand for gas increases, the availability of cheap stranded gas is likely to decline and with it such options for gas-to-liquids (GTL) plants. The IEA WEO projects global GTL capacity of 2.3 mb/d by 2030 (IEA, 2004a). It is not evident that FT-synthesis based on Middle East stranded gas, or LNG from the Middle East would also enhance the security of supply in the long term. Outside the Middle East, the long-term availability of sufficient stranded gas (*i.e.* cheap gas) to fuel the world transportation fleet is less evident. The total amount of stranded gas in Figure 4.2 currently amounts to 6 000 EJ, or around half of total global gas reserves. This is equivalent to 60 years of current gas use, but the bulk of the stranded gas resources are in politically volatile regions.

Figure 4.2

Stranded gas resources, by region



Source: IEA data.

Key point: *Stranded gas is concentrated in the same regions as oil reserves*

At the moment, a 40% liquid product yield (in energy terms) can be attained by coal based FT processes (Steynberg and Nel, 2004). Coal-based production is less sensitive to feedstock prices than the gas-based production, because capital costs are considerably higher due to the additional cost of coal gasification, oxygen production, etc. The investment cost for an 80 000 bpd CTL plant is around USD 5 billion.

Current gas-based FT production costs are USD 25-30/bbl (USD 5-6 /GJ liquids), given a gas price of USD 0.5/GJ (Marsh *et al.* 2003). For the CTL process the production cost is estimated to be about USD 8-10/GJ liquid at a coal price of USD 1/GJ (Williams and Larson, 2003). This corresponds to a liquid fuel price of USD 45-55/bbl and to a crude oil price of 30-45 USD/bbl. However, current United States designs for plants at the mine-mouth that use lignite at USD 0.5/GJ indicate an even lower production cost of around USD 30/bbl of crude equivalent (Pedersen, 2005). A GTL project needs at least 1.5 EJ gas in place, while a CTL process will only be economic for locations with at least 2-4 Gt of coal reserves in place.

In the case of gas feedstock use, between 17% and 25% of the carbon entering the process is released as a process emission (the remainder rests in the liquid synfuel product). However, when coal is used as a feedstock, the process emission amounts to more than 50% of the carbon in the coal. In the future, CO_2 capture and storage could be applied in order to reduce or eliminate the CO_2 emissions.

In recent years, the co-production of electricity and synfuels such as methanol, FT-diesel and hydrogen from coal, has been receiving increasing attention. Co-production would allow a high average load factor, which would reduce the capital cost component 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 from 40% to 50%, compared to the same plant without electricity cogeneration. Such plants would produce synfuel and electricity in an 8:1 ratio (Steynberg and Nel, 2004), while analysis suggests that synfuel production costs may be reduced by 10 percent if a co-production strategy is applied (Yamashita and Barreto, 2003, Williams and Larson, 2003).

Other fuels under discussion are methanol and DiMethylEther (DME). Contrary to methanol, DME is non-toxic. Both fuels could be produced from a wide range of feedstocks including coal, natural gas and biomass. Methanol production from natural gas is an established technology. Currently, the bulk of methanol produced is used in the manufacture of chemicals.

Current DME production takes place in two-steps. First methanol is produced from syngas, which is then catalytically dehydrated into DME. New production processes are under development where DME is produced directly from syngas in a single step. Various process designs have been proposed for the co-production of methanol and DME, and for the cogeneration of DME and electricity. Such designs circumvent the problem of re-circulation of products because of incomplete conversion of feedstock into DME (Air Products, 2002; Ogawa *et al.*, 2003). DME can be used as a fuel for power generation turbines, diesel engines, or as an LPG replacement in households. Current global DME production amounts to 0.15 Mt per year. Its main use is as an aerosol propellant for hair spray. Two coal-based DME plants are in operation in China, with a total capacity of 40 kt a year. A rapid expansion of Chinese DME production is planned, to more than 1 Mt a year (0.03 EJ/yr) in 2009 (Fleisch, 2004), while further gas-based projects are planned in the Middle East.

Non-conventional oil

There are three types of non-conventional oil resources: heavy oil, oil sands and bitumen, and oil shales. Medium heavy oil and extra heavy oil have a density ranging from 25° API to 7° API, and a viscosity ranging from 10 to 10 000 centiPoise (cP). These resources are mobile at reservoir conditions. Oil sands and bitumen in contrast are not mobile at reservoir conditions and have a density ranging from 12° API to 7° API, and a viscosity above 10 000 cP. The reserves of extra heavy oils are concentrated in Venezuela, while the tar sands and bitumen reserves are concentrated in Canada. The amount of heavy oil in place (recoverable reserves) is 1 200 Gbbl and for tar sands and bitumen it is 1 630 Gbbl. These two countries represent together about 80% of worldwide reserves. Canada's tar sands and bitumen reserves are estimated at 310 Gbbl, while Venezuela's heavy oil reserves are 270 Gbbl. This makes the reserves of each of these countries similar to the oil reserves of Saudi Arabia

Oil sands contain around 10-15% bitumen, while 10% of oil sands are situated within 50 meters of the surface and can be economically mined in open pits. The oil recovery from oil sands that are surface mined is high and can be up to 90%. The remaining 90% of oil sand resources can be mined using in-situ technologies that have much lower recovery rates of around 10-20%. A number of underground (in-situ) production techniques are used, including: cyclic steam stimulation (CSS), pressure cyclic steam drive (PCSD), cold heavy oil production with sand (CHOPS) and solvent injection and steam assisted gravity drainage (SAGD).

Given the better economics, open cast mining is currently the main production technology in Canada, accounting for about 80% of total production. The mined sand is transported to a processing plant where the bitumen is removed using mixing and cleaning processes that utilise water, caustic soda and some form of agitation. Following the cleaning, the bitumen is diluted with naphthalene and sent to an upgrader. The heating of the bitumen to about 500 °C then yields about 70% syncrude. This syncrude has good yields of kerosene and other middle distillates. The remaining fraction either thermally cracks to form gaseous products or it is converted into petcoke.

The main CSS application is the Imperial Oil Cold Lake project (0.11 Mbpd in 2002). In this project steam is injected for some time, which is followed by production of the heated liquid bitumen (about 80 °C). In the case of SAGD two horizontal wells are used on top of each other. Steam is injected in the upper well and another well below the steam injection well is used for recovery of the liquefied bitumen. SAGD has been tested at a pilot-plant scale (0.05 Mbpd in 2002 in 10 projects). Solvent injection uses the same double-well approach but with organic solvents instead of water. SAGD could increase the recovery efficiency from less than 10% to 40%, which would increase the recoverable reserves substantially. If this can be proven in practice, it has the potential to raise the global reserves of oil sand and heavy oil to the level of conventional oil reserves.

However, the production of oil sands is energy, and hence CO_2, intensive. CSS requires approximately 1-1.4 GJ natural gas per barrel of bitumen produced and 20 kWh of electricity (0.18-0.23 GJ per GJ of bitumen produced). Approximately 75 kg of CO_2 are released per barrel of bitumen produced for CSS and up to 109 kg per barrel (12-18 kg CO_2/GJ) for steam assisted extraction (Foley, 2001). The total emissions are therefore substantially higher than for conventional oil production.

The CSS steam-to-oil ratio is about 5:1. For SAGD, it is 2:1 to 4:1, with a potential for further reduction to 2:1 or even 1:1 for solvent based processes (Ali, 2003). So a significant potential exists to decrease energy use and emissions. On top of the emissions in bitumen production there are the emissions from the bitumen upgrading. However, in the case where residues from upgrading are used to generate the steam, no additional gas is needed (*e.g.* in case of the Canadian Long Lake project).

The operating cost for SAGD would be about USD 3/bbl, if gas is used to generate the steam, and USD 1/bbl if upgrading residues are used. The capital cost and upgrading cost must then be added to the operating costs. The total technical cost of production and upgrading is about USD 15/bbl. The cost of adding CO_2 capture to reduce upstream emissions may increase costs by USD 5/bbl (Cupcic, 2003).

The temperature of the reservoirs in the Venezuelan Orinoco tar sands at 1000 m depth is 55 °C. This high reservoir temperature reduces the viscosity of the oil and means the oil can be recovered without, or with very limited, thermal stimulation (a steam-to-oil ratio of 0.3) (Ali, 2003). The heavy oil, which has an average gravity of 9.5°API (1.00 t/m3), is extracted from wells that are arranged in clusters, using screw pumps. The production costs are well below the price for conventional oil and this explains the rapidly increasing production of this type of oil.

Canada produced 829 million barrels of bitumen in 2002 (Alberta 2003). By 2011, Alberta's oil sands are expected to generate nearly 2 mbpd of crude oil representing 57 per cent of Canada's projected total crude oil production at that time. Venezuela has plans to apply deep conversion technology to the heavy oil in order to produce high-value transportation fuels. Delayed coking is the primary conversion technology. Plans are to produce 622 000 bpd of syncrude by 2009.

Total Canadian and Venezuelan production will probably be around 3 mbpd of crude oil equivalent in 2010, or 3% of world oil production. The IEA World Energy Outlook projects a total syncrude production from both sources of 6 mbpd by 2030 (IEA, 2004a). This production is based on very large multi-billion dollar projects, whose planning takes time. Such projects require a stable policy environment. Such an environment is given for Canada, but less evident in the case of Venezuela.

Oil shale is an inorganic rock that contains kerogen, a type of immature oil that has never been exposed to high temperatures. Lean shale contains about 4% kerogen. Rich shale contains about 40% kerogen. When the rock is heated to 350-400 °C it yields 20-200 litres of oil per ton of shale. Advanced oil shale processing would generate roughly 286 kg CO_2/bbl (54 kg/GJ) compared to 59 kg CO_2/bbl (11 kg/GJ) for conventional oil. Reductions to 169 kg/bbl (32 kg/GJ) are planned (Innovest Strategic Value Advisors, 2001). The raw shale oil produced would constitute a relatively light crude with a 42° API gravity, 0.4wt% sulphur and 1.0wt% nitrogen. The oil is further processed into hydro-treated naphtha and low sulphur medium shale oil of 27° API.

The world's largest oil shale project was the Stuart shale oil project in Australia. The plant was heavily opposed by NGOs. In July 2004 it was announced that the plant would be closed down. There are some oil shale mining activities in Estonia, Brazil and China, but they are on a small scale. The bulk of the global oil shale resources are located in the United States. There is more than 500 Gbbl of oil in place in oil shales of more than 25 gallon/ton, in a layer at least 3 metres thick. Lower-quality resources are double this figure (DOE 2004a). In-situ recovery methods are under development that could reduce the environmental impacts of oil shale production dramatically. The mining and upgrading of oil shale to syncrude costs USD 30/bbl, if the in-situ process is applied (Shell estimate). Given the successful development of the Canadian oil sands industry, oil shale processing may emerge in coming years as a new source of production. However, even if a significant share of global oil supply could technically be produced from oil shale in the long term, it is unlikely that an industry of more than 1 mbpd will be operational by 2020.

Compressed natural gas (CNG)

Car engines can run on natural gas. This requires some minor modifications to gasoline engines. The use of gas requires a gas tank, and it shortens the life span of the engine. Retro-fitting mid-size gasoline cars to natural gas costs currently USD 2 200 - 3 400 per car. An additional disadvantage is that the power output of the car is reduced by 15-20%. At the moment such a retro-fit is attractive in Germany because natural gas is not subject to the substantial fuel taxes of oil fuels. However, its expansion is limited by the availability of natural gas refuelling stations. In terms of cost, the retro-fit investment is equivalent to USD 0.35/litre of gasoline equivalent, or USD 10/GJ. These capital costs are not negligible, and must be taken into account for proper comparison of alternative fuels. World wide there are about 3.8 million natural gas-fuelled vehicles, mainly in Argentina, Brazil, Pakistan, Italy, India and the United States (IANGV, 2004). This equals about 0.5% of the world vehicle stock. This makes CNG a serious alternative transportation fuel option.

Alternative fuels and energy policy targets

Figure 4.3 shows a qualitative assessment of transportation fuel options and their *perceived* contribution to energy-security and CO_2 emissions reductions. Obviously, this classification is only indicative and would differ by region, depending on the resource endowment and energy system structure. However, it suggests that certain hydrogen energy chains can enhance the security of energy supply and reduce CO_2 emissions. Other options in this category are biofuels and energy efficiency.

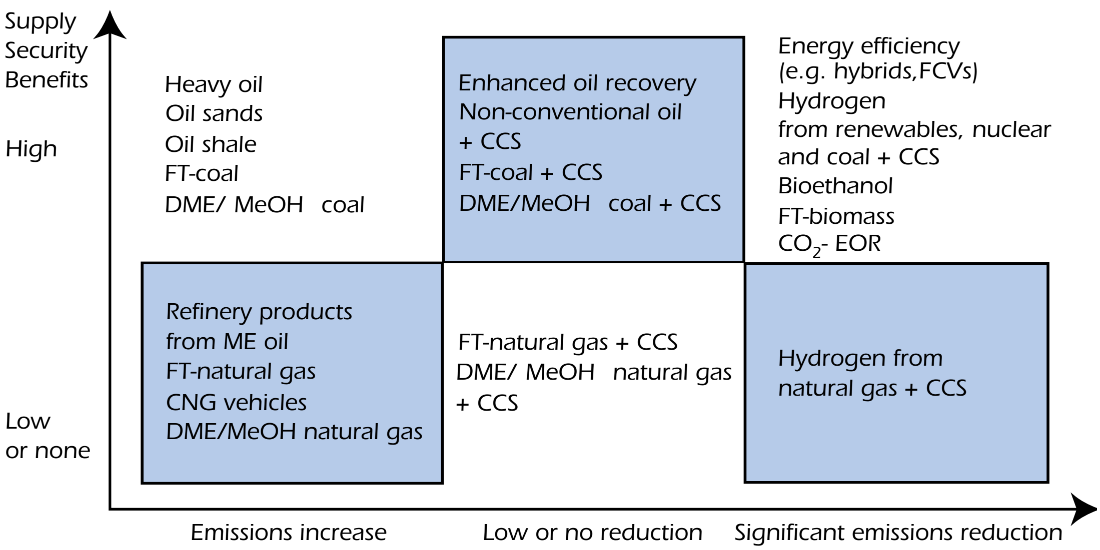
The impact of taxes

Fuel taxes constitute a key cost component of transport fuels in many world regions. They range from virtually zero to more than USD 30/GJ in certain European countries (see Annex 2). Compared to the gasoline supply cost of less than USD 10/GJ, this quadruples the price a final consumer pays. As a result, any fuel cost comparison or evaluation of investment choices for a consumer depends heavily on the taxation regime. For example, alternative fuels such as LNG and CNG are currently exempt from fuel taxes, or are taxed at a much lower rate, in many countries. However, because different fuels can imply different fuel efficiencies, a fuel tax that increases the fuel price four-fold may result in a much higher incentive to switch to higher efficiency options.

A comparison of the future of one fuel with excise tax and another one that is exempt from such tax is of limited value, because it does not account for the loss of government revenues. Fuel taxes are a key source of revenues in many countries. For example, in the EU-15 the weighted average excise duty is EUR 411 per 1 000 litres of diesel and EUR 581 per 1 000 litres of gasoline (EU 2002), yielding fuel duties of EUR 161 bn in 2002. This equals almost 9.4% of total government revenues in this region. Clearly, tax exemptions cannot be sustained once a fuel gains a significant market share. If the tax revenues need to be maintained at the same level, the taxes per unit of energy need to rise if the energy efficiency increases. This study assumes that the taxes for gasoline and diesel do not increase in absolute terms, but that fuel taxes for alternative fuels increase gradually from zero to 75% of gasoline taxes by 2050. Other tax scenarios can be envisaged, but the assessment of the economic implications of alternative tax policies is beyond the scope of the partial equilibrium ETP model. Macroeconomic models are needed to assess these issues.

Figure 4.3

Transportation fuel supply options and their contribution to energy policy goals



Source: IEA.

Key point: *Hydrogen is one of the options to enhance energy-security and reduce emissions*

Competing options for stationary applications

Residential uses

Existing buildings are usually connected to the electricity grid and equipped with systems to generate heat and hot water from fossil fuels or electricity. In certain regions where winter heating and summer cooling are needed, heat pumps have a significant market share. CHP systems have traditionally received a lot of attention in regions with long heating seasons without the need for summer cooling. However, CHP systems are gradually gaining market share in other regions.

Gas is one of the most widely used residential heating fuels in industrialised countries. Old gas boilers may achieve an efficiency of 75% (room-based systems) to 85% (centralised systems). New condensing gas boilers can achieve up to 107% efficiency (Holsteijn, 2002). Efficiencies of 140% can be achieved through a combination of a gas-fired heat pump and a condensing boiler. A range of small improvements are possible for boilers, such as replacing the pilot flame by electric-ignition (5% savings), reduced heat capacity of on/off burners (4% savings), or water pumps with permanent magnet motors (4% savings) (Holsteijn, 2002). The distribution system, the emitters and the room temperature control system also matter. Savings of between 10% and 20% can be achieved through options such as improved piping insulation, low temperature/large-surface radiators, or behavioural feedback control units with room thermostats (Holsteijn and Kemna, 2001). Low capacity factors may pose important limitations for a switch to more energy-efficient, but high capital-cost technologies.

Apart from high-efficiency fossil-fuelled boilers, solar heating systems are making inroads in many regions. The total global capacity of solar heaters stood at almost 93 GW in 2003 (Weiss *et al.*, 2005). The total yield from these systems was 0.2 EJ, compared to 50 EJ fossil fuel use in the residential and commercial sector, or a 0.5% share. While their current use is still limited, the growth rate is around 20% per year. Most solar heating systems are used to generate hot water. Their future expansion, possibly in combination with heat pumps and insulation measures, could limit the market potential for residential fuel cells.

The demand for heat depends on the climate, the insulation level and the desired interior temperature. The average household temperature in the UK has risen from 13 °C to 18 °C over the last 30 years, and a further increase to 20 °C is projected by 2020 (Powergen, 2003). Cultural differences can also play an important role. In Japan, traditional one-room heating systems based on kerosene burners are still widely used, in combination with an electric heating system under the table (a "kotatsu"). These cultural differences can affect the prospects for fuel cells in the residential and commercial sectors and must be assessed on a regional, or even national basis.

For space and hot water heating one can differentiate, in general terms, between systems that convert heat into useful energy (burners and boilers), and systems that use energy to separate energy from the environment into a hot and a cold part (chillers and heat pumps). Chillers and heat pumps can achieve efficiencies that are well above 100%, because the energy taken from the environment is "free". These systems are slowly penetrating the market. Their main disadvantages are that they require high-quality fuels such as electricity or gas, and that they have a high investment cost due to their complex technology. Therefore, the bulk of energy services are still delivered by systems that convert fossil energy or electricity directly into useful energy. A gradual trend exists toward heat pumps, aided by the move to packaged systems. These standardised modular systems have achieved cost reductions due to the economies of scale in standardised factory production.

The global thermal output from residential heat pumps stood at 2.7 EJ in 2001 (Halozan and Gilli, 2002). On top of that there was 1.26 EJ of thermal output from commercial heat pumps and 0.73 EJ from industrial heat pumps. The total thermal output therefore amounted to 4.7 EJ of useful energy, while the electricity use amounted to 2-2.5 EJ. Around 130-140 million heat pumps are installed around the world. Most of these systems are installed for heat and cold cogeneration. In Japan, 20% of the residential demand for heat is met by heat pumps, in the United States their share is about 7%, while in Europe it is less than 2% (mainly in Scandinavia and Spain). In principle, the heat from heat pumps can also be used to generate cold, but such a system is complex and costly and is therefore not analysed in more detail.

Other emerging technologies such as Stirling engines, ICEs and Rankine cycle engines compete with fuel cells in the small-scale CHP market (Wilcox, 2004). The Rankine cycles seem far from market introduction and will not be discussed in more detail. An overview of the status of the other two systems in Europe is shown in Table 4.1. 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 (1-4 kW vs. 10-20 kW). The reason for this is that the ICE system cost rises 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.

Table 4.1

Characteristics of Stirling engines and ICE CHP systems

Producer	Electric (kWel)	Thermal (kWth)	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 Euros 10,000 units installed
VAILLANT/Ecopower	4.7	12	Demonstration units

Source: Wilcox, 2004.

Power generation

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 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.

Combined heat and power production is the largest segment of the existing decentralised generation market. Large-scale CHP systems, based on gas turbines or boilers, represent 96% of the CHP market world wide (WADE, 2003). 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 due to 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 favorable when compared to large-scale centralised electricity supply options with grid delivery. A state-of-the-art gas-fired combined cycle plant can achieve a net electric efficiency of 57%, while a state-of-the-art hard coal-fired power plant under supercritical steam conditions can achieve net electric efficiency 46% (Meier *et al.*, 2004). Moreover, a substantial potential exists to increase the efficiencies of these conventional technologies even further, to 50-55% for coal-fired plants (IGCC and ultra-supercritical steam cycles) and to greater than 60% for gas-fired power plants. These values are higher than the 40-50% electric efficiency that is projected for decentralised fuel cell systems, even if the 5-7% 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 fuel cells 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.

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 (*e.g.* 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.

Prospects also exist for fuel cell integration into centralised power production. The current target is to integrate fuel cells into medium-sized power plants of several tens of MW. This could represent a balanced strategy that takes advantage of the benefits of decentralised production (such as cogeneration) and centralised production (such as economies of scale and high electric efficiency). Depending on the specific application and operating conditions, SOFCs, MCFCs, or even PEMFCs may be competitive. A speculative scenario - not considered in this study - might be where technology breakthroughs in decentralised hydrogen production systems resulted in the use of PEMFCs and FCVs not only in transport applications, but also for decentralised power production in the residential and commercial sectors. This would allow for spill-over learning effects between sectors.

Chapter 5.
DEFINING THE ENERGY CONTEXT

HIGHLIGHTS

- The analysis of two basic scenarios helps define the energy context (BASE Scenario) and map the key drivers and policies for hydrogen and fuel cells (MAP Scenario). These two scenarios provide the starting point for analysing the potential of hydrogen and fuel cells under a range of different assumptions.

- The BASE scenario is a business-as-usual scenario which includes only currently enacted energy policies. In the absence of significant new climate policies, energy demand more than doubles by 2050 and CO_2 emissions reach almost 60 Gt of CO_2 per year. Fuel use in the transport sector also increases, but improvements in vehicle efficiency result in almost 20% lower fuel demand in comparison with the IEAs WEO 2004 Reference Scenario projections for 2030. Important changes occur in the supply of transportation fuels beyond 2030. In 2050, about 40% of the demand in the transportation sector is supplied by alternative fuels, primarily FT synfuels from coal and gas (some 30%) and biofuels (less than 10%). In addition, the use of efficient technologies limits the growth in demand for conventional oil refinery products. However, hydrogen plays a negligible role, due in part to the success of other non-conventional fuels. This result suggests that business-as-usual trends in energy policy will not necessarily result in switching to hydrogen and fuel cells, even in the presence of energy-security concerns.

- The MAP scenario includes a global incentive of USD 50/t of CO_2 as a proxy to represent a set of new policies and measures aimed at reducing emissions and improving energy-security. In the presence of these policies, global emissions are stabilised below 30 Gt of CO_2 per year over the projection period. Total energy use declines by 8% in 2050 compared to the BASE scenario and the use of renewable energy increases at the expense of coal. The combination of effective climate and energy-security policies makes hydrogen a significant player in the market for transport fuels. Oil still accounts for more than 50% of the fuel demand, but biofuels gain 25% of the market, hydrogen gains 10% and FT synfuels 10%.

- In the MAP scenario hydrogen use in 2050 amounts to 15.7 EJ. Around 90% of this hydrogen is used in the transport sector, primarily in passenger cars. Initially, hydrogen-hybrid vehicles play a important role, but from 2025 onwards sales of FCVs takeoff. Although, the total demand for hydrogen may appear small, the high efficiency of FCVs means that this hydrogen is fueling some 27% of all passenger cars in 2050.

- As the MAP scenario is solely intended to “map” key parameters and hydrogen technologies, it is not a “best guess” scenario for hydrogen and fuel cells. For instance, it does not account for transition issues such as the chicken-or-egg problem. Hydrogen-specific scenarios based on consistent sets of assumptions are discussed in Chapter 7.

- In both the BASE and MAP scenarios, the installed capacity of stationary fuel cells – which are not necessarily fuelled by hydrogen – is about 5% of global electricity production capacity in 2050. They are concentrated in industry, residential and commercial sectors. The fact that fuel cells are selected in both the BASE and MAP scenarios, despite the different policy settings, suggests that they are a robust and competitive technology option in niche markets.

After a brief description of the ETP model, this chapter describes the structure of the model analysis. It then discusses the results of the basic preparatory work that defines the reference scenarios and identifies the key drivers (technologies, policies and assumptions) for hydrogen and fuel cells to "take off" in the energy market.

All scenarios in this analysis are compared to the ETP BASE scenario. The BASE scenario includes energy and climate policies enacted before mid-2004. This means there are no substantial CO_2 or energy-security policies in the post-Kyoto period, and no incentives to reduce CO_2 emissions. A brief discussion of the BASE scenario is followed by a detailed discussion of the MAP reference scenario, which includes CO_2 and energy-security policies. The name MAP refers to the fact that this scenario is intended to "map" the key technologies and drivers for hydrogen and fuel cells. Building on the MAP scenario, a sensitivity analysis explores the impact of varying individual parameters on the potential of hydrogen and fuel cells. The results of this analysis are discussed in Chapter 6. Chapter 7 discusses four more hydrogen-specific scenarios that provide an insight into the long-term opportunities for hydrogen and fuel cells, as well as the combined impact of drivers and policies.

The Energy Technology Perspectives model

The IEA Energy Technology Perspective model is a bottom-up engineering-economic model that is based on the MARKAL (MARKet ALlocation) linear-programming model system (Fishbone and Abilock, 1981 and Loulou *et al.*, 2004). The MARKAL model system has been developed over the past 30 years by the IEA Implementing Agreement on Energy Technology Systems Analysis Programme (ETSAP, 2004 and ETSAP, 2005). It is a technical tool to analyse technology competition and technology policies in the energy market, and to support decision-making in the energy sector. Given the current energy system and technology mix, MARKAL models analyse their evolution over time and provides minimum-cost configurations, given selected assumptions for energy policies and technology development. This class of models *is not intended for forecasting*, but for analysing the role of technologies and policies by taking into account basic assumptions and uncertainties. MARKAL-type models are also known as partial-equilibrium models, as they only provide a microeconomic representation of the part of the world economy that is relevant to energy (*e.g.* they do not model the negative impact of higher energy costs on economic growth).

The ETP model includes 15 world regions and accounts for energy trading among these regions. The energy system is modelled by a number of inter-dependent processes and flows represented through their technical and economic characteristics. At present, the ETP model incorporates 1 500 energy demand and supply technologies, including energy production, extraction, conversion, transport, distribution and end-use technologies (in the transport, industry, services and residential sectors). Given a certain demand for energy services and appropriate normative and technical constraints (*e.g.* policy measures, natural resource availability, technical limitations for capacity building, etc.), the model determines the least-cost configuration of the energy system over time, and determines the optimal physical and monetary flows. The model provides an abstract representation of the real world where decisions are based on rigid optimisation criteria (*i.e.* least-cost). User-defined constraints help represent the "real world" that is characterised by non-optimal decisions. More information on the ETP model and its technology database is given in Annex 1 and 2.

Overview of the analysis

Figure 5.1 provides an overview of the analyses carried out in this study, the results of which are reported in Chapters 5 to 7. A set of 40 model runs has been carried out to provide an insight into the future role of hydrogen and fuel cells in the energy market. The results include the:

- Market potential for hydrogen and fuel cells.
- Cost implications for the global energy system.
- Key drivers for gaining market share and transition issues.
- Impact of different types and levels of policies and incentives.
- Impact on different world regions.
- The contribution of hydrogen and fuel cells to energy policy targets.

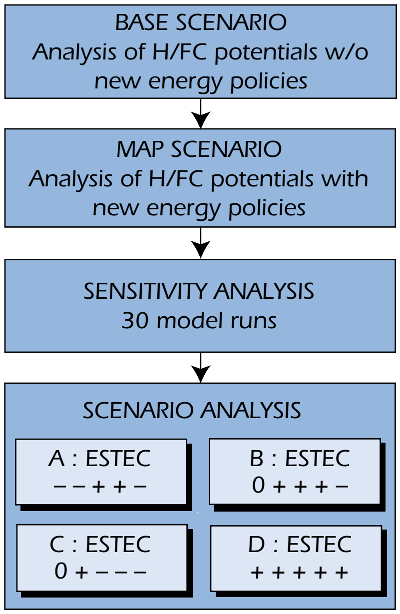
The impacts of hydrogen and fuel cell technologies are analysed from the perspective of the three shared goals of the IEA, namely: energy-security, environmental protection and affordable energy energy supplies for economic growth.

The baseline for the analysis (see Figure 5.1) is set by looking at the ETP BASE scenario. As mentioned above, this scenario includes energy and climate policies enacted before mid-2004. It is a business-as-usual scenario with no new environmental or energy-security policies. This scenario provides the base set of results to which other model scenarios are compared. The analysis continues with the MAP scenario that includes a global incentive to reduce CO_2 emissions. The incentive is a *modelling instrument* that is used to represent a range of regulatory and policy measures aimed at mitigating climate change and improving energy-security. The MAP scenario is intended to map the key technologies and drivers for hydrogen and fuel cells.

Based on the results of the MAP scenario, a sensitivity analysis has been carried out to investigate the impact of varying individual drivers such as technology improvements, policy measures and economic parameters. The results of the MAP scenario and the sensitivity analysis have then been used to define four more hydrogen-specific scenarios that analyse the combined effect of a full range of policies and key drivers on the potential of hydrogen and fuel cells. These scenarios (Figure 5.1) are characterised by the acronym ESTEC: environment (E), supply security (S), technological progress (T), economic conditions (E) and competing options (C). A *plus* (+) sign beneath each letter of the acronym means that parameter values have a positive impact on hydrogen and fuel cell potential, while the *minus* (-) sign indicates negative effects. A zero (0) indicates that the parameter value is somewhere in between. The scenarios present the interaction of positive and negative factors that affect the potential of hydrogen and fuel cells, and provide information and suggestions regarding the related policies and benefits in terms of emission mitigation and energy-security. The most optimistic outlook for hydrogen and fuel cells is provided by the ESTEC +++++ scenario.

Figure 5.1

The structure of the hydrogen and fuel cells model analysis



- Business-as–usual scenario with no new policies to improve energy-security, reduce emissions, or support hydrogen and fuel cells.
- Results in Chapter 5.

- Reference scenario for hydrogen and fuel cells including new policies to improve energy-security and reduce emissions.
- Results in Chapter 5.

- Impact of individual drivers on hydrogen and fuel cells, and related uncertainties.
- Results in Chapter 6.

- Combined effects of key drivers and policies on the potential of hydrogen and fuel cells.
- Contribution of hydrogen and fuel cells to emission reduction and energy-security.
- Conclusions and policy suggestions to foster the introduction of hydrogen and fuel cells.
- Results in Chapter 7.

Note: H/FC = hydrogen and fuel cells.

The ETP BASE scenario

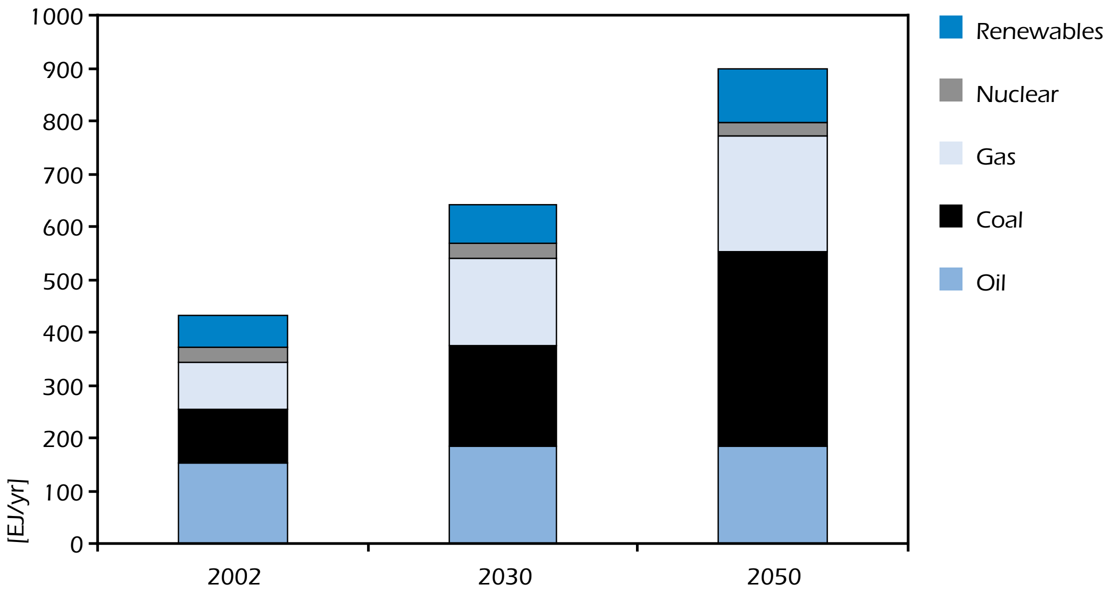
The ETP BASE scenario builds on the IEA *World Energy Outlook* Reference Scenario (IEA, 2004a) up to 2030 and then further develops this outlook up to 2050. Like the WEO 2004 Reference Scenario, the BASE scenario includes moderately increasing energy prices and climate and energy-security policies enacted before mid-2004. This means there are no speculative assumptions about new climate and energy-security policies in the period after the first-commitment phase of the Kyoto Protocol and no new incentives to reduce CO_2 emissions. The only incentives for change are changing resource prices, increasing demand for energy services and technology advances due to RD&D. Under these conditions conventional processes and technologies are generally preferred over newer innovative processes with lower emissions, but with higher costs. For the period 2030 to 2050, the BASE scenario is the result of extrapolated demand projections and technology/fuel choices driven by the model algorithm and business-as-usual technology assumptions. No additional policy is implemented beyond those included in the WEO Reference Scenario.

Primary energy demand in the BASE scenario more than doubles in 50 years (Figure 5.2). With no new climate change policies, this scenario implies a continued reliance on fossil fuels. The demand growth is mainly accounted for by coal and, to a lesser extent, natural gas and oil. The high growth of coal is explained by its low price compared to oil and gas, and the introduction of new coal conversion technologies. CO_2 emissions in this scenario increase substantially to almost 60 Gt of CO_2 per year in 2050.

The BASE scenario does not show any significant hydrogen use. However, over 400 GW of stationary fuel cells using other fuels are in use by 2050. In this scenario the demand for transportation fuels doubles in the period 2000-2050 (Figure 5.3). While passenger cars and light/medium-size trucks

Figure 5.2

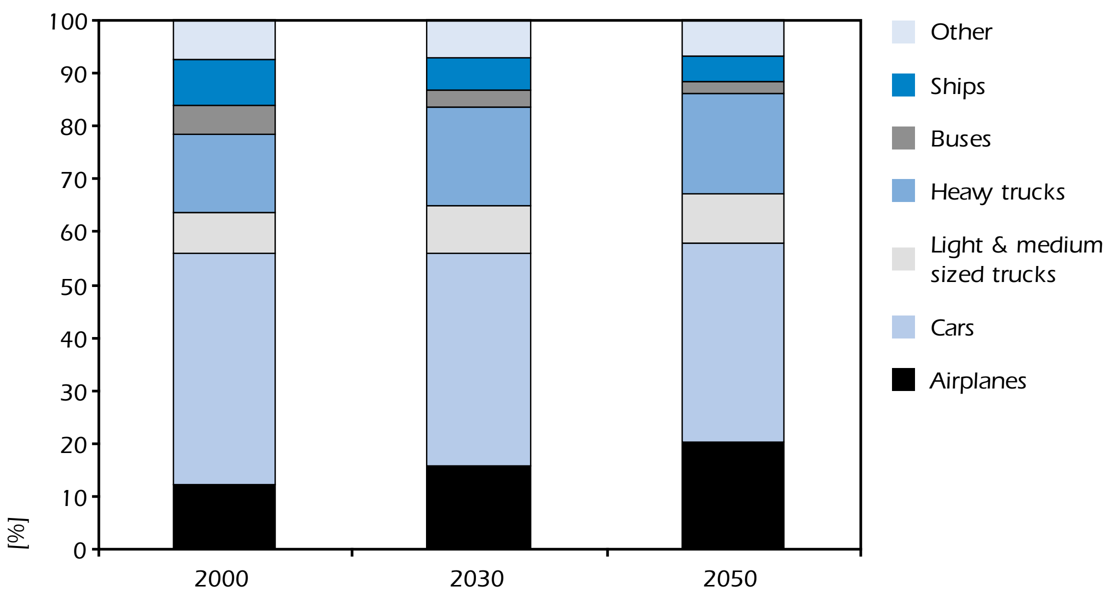
Primary energy demand projections (BASE scenario)



Key point: Fossil fuels account for most of the increase in primary energy supply without new policies

Figure 5.3

Fuel use by mode in the transportation sector (BASE scenario)



Key point: Cars, trucks and airplanes must be targeted to reduce fuel consumption and emissions substantially account for 47% of total fuel use in 2050, heavy trucks and airplanes also consume significant amounts of fuel, and grow at a faster rate than passenger cars over the period 2000-2050. In the BASE scenario, fuel demand for transport in 2050 is largely met by oil products and Fischer-Tropsch fuels produced from coal and natural gas. However, ethanol constitutes about 10% of total fuel use for transport in 2050. This is driven by the favourable economics of these biofuels due to continued cost reductions and contributes to a significant CO_2 emission reduction. Emission reduction policies would need to consider alternative options to oil and synfuels derived from fossil fuels for all important transportation modes (including heavy trucks and airplanes). A strategy that is only based on hydrogen and fuel cells would not be sufficient to make large savings.

The MAP scenario

In the MAP scenario, the incentive to reduce CO_2 emissions is expressed as a benefit in USD per tonne of CO_2 equivalent. It increases gradually over time to USD 50/t of CO_2. This incentive is universally applied to all sectors and end-uses. The maximum value of USD 50/t of CO_2 was chosen because it results in emissions stabilising over the period 2000-2050 at roughly 23-27 Gt of CO_2 per year. This corresponds to a halving of the emissions in 2050, compared to the BASE scenario (Figure 5.6). The incentive is a proxy to represent a wide-range of possible regulatory measures, subsidies or other policy instruments that promote emission reduction technologies, including hydrogen and fuel cells. The effect of these policies and measures is modelled as being equivalent to giving these technologies a value of USD 50/t of CO_2 saved. While a technology-neutral scheme providing a uniform USD 50/t incentive (marginal cost) may be difficult to achieve in practice, for modelling purposes it is much easier to represent a generic set of regulations and incentives in this way. Indeed, the actual specification of these policies in the model would not provide any further insights regarding their cost-effectiveness. In contrast, the approach used in this study helps to select cost-effective technology options.

It is worth noting that the MAP scenario should not be considered as a “best guess” scenario for hydrogen and fuel cells. Significant uncertainties can affect the results. Parameter values will be varied according to the results of the present analysis and the sensitivity analysis elaborated in Chapter 6. Moreover, the MAP scenario does not consider transition issues, but only provides an insight into the cost-optimal, long-term perspective for hydrogen and fuel cells. A more refined set of assumptions are used in the four hydrogen-specific scenarios discussed in Chapter 7.

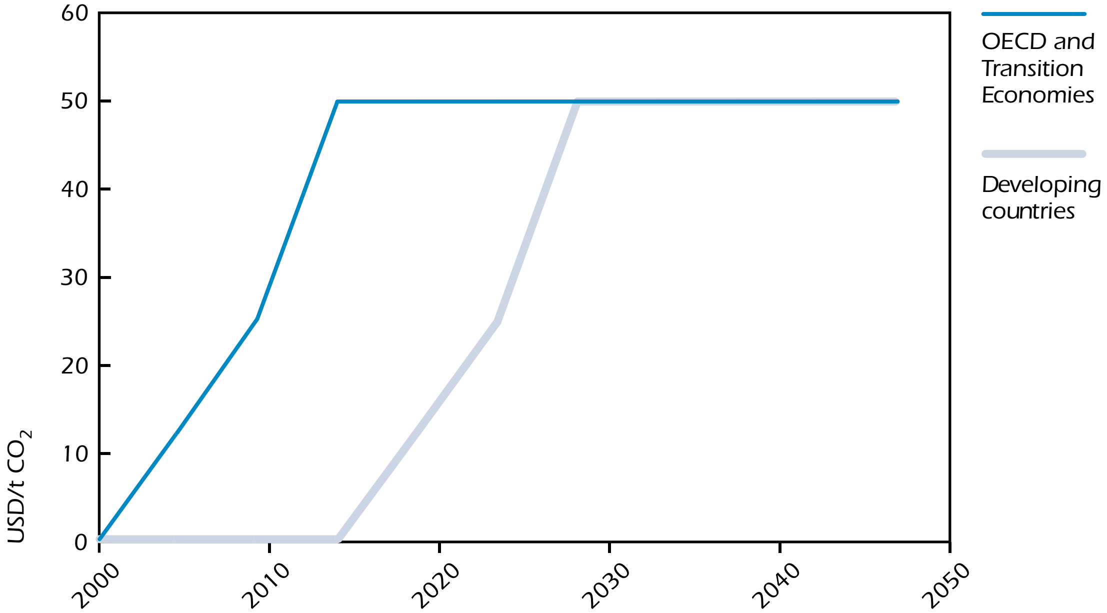
In the MAP scenario, the incentive applies to all CO_2 emissions from the energy system, but is introduced in different regions at different times. It is assumed that the incentive is introduced in 2005 in industrialised countries and that the level of USD 50/t of CO_2 is reached in 2015 (Figure 5.4). In developing countries the incentive is introduced in 2020 and reaches its maximum level in 2030.

The value of USD 50/t of CO_2 from 2015 onward in industrialised countries can be compared to the current CO_2 permit prices in the European Emissions Trading Scheme. The price of these permits was around EUR 20/t of CO_2 (USD 25/t of CO_2) on 1 June 2005. The current price level would suggest that USD 50/t of CO_2 in 10 years from now is not unreasonable. However, the European trading scheme does not apply to all emissions sources and other OECD countries, notably the United States, which have no such incentives or plans to introduce them. Also, an incentive of

USD 50/t of CO_2 from 2030 may appear high for developing countries. However, it is not impossible that such incentives could be applied in developing countries in the long term given they also share the developed world's environmental and energy-security concerns, if not the means to combat them. Critically, their rapid economic development may make this feasible. In the model scenarios, the 2050 per capita GDP in all regions except Africa is close to, or higher than, the per capita GDP in OECD Europe in 2000 (see Annex 2).

Figure 5.4

CO_2 incentives in the MAP scenario



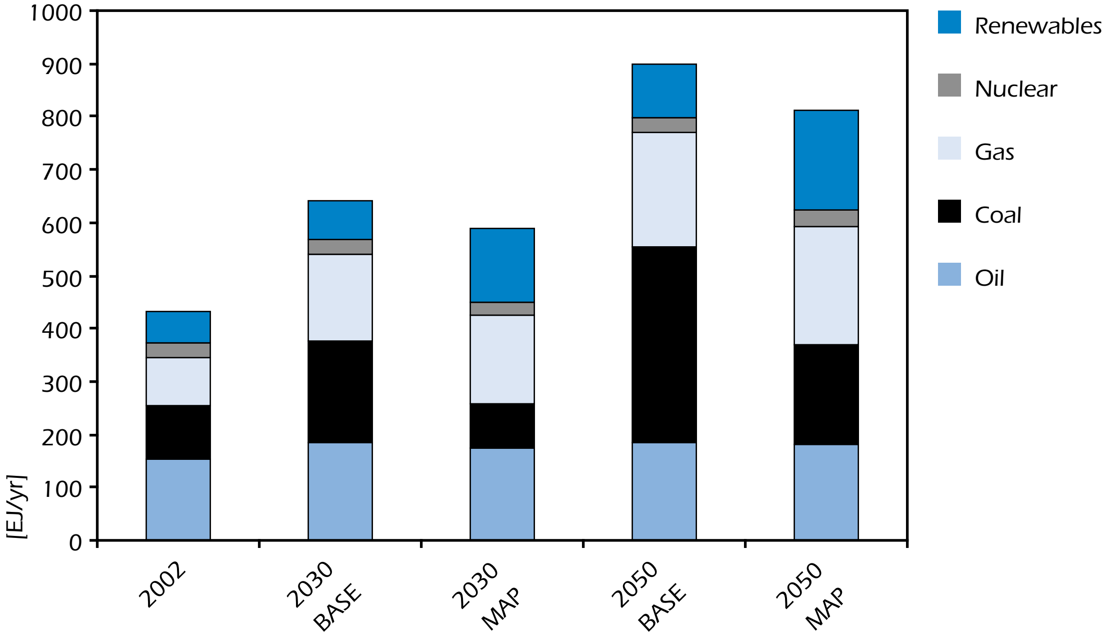
Key point: *Developing countries follow the industrialised world with a 15 year lag*

Total primary energy use in the MAP scenario is about 850 EJ in 2050 (Figure 5.5), only 8% lower than in the BASE scenario. This decline is the net result of fuel switching, improved efficiency, and increased energy-use to mitigate emissions (*e.g.* CO_2 capture and storage). Coal use in 2050 is significantly lower than in the BASE scenario, but in absolute terms it is stable up to 2030 and shows significant growth beyond this date in combination with CCS. The use of gas is virtually unchanged from the BASE scenario, while renewable energy use increases by 80%. The use of biomass is twice as high as in the BASE scenario, while wind energy more than doubles. Nuclear shows no growth in absolute terms and a decline in relative terms. This is largely explained by constraints applied in the model to represent current trends in the social acceptance of nuclear energy, in line with the *World Energy Outlook* (IEA, 2004a).

In the BASE scenario, emissions grow by 1.8% per year between 2000 and 2050, while in the MAP scenario emissions stabilise at between 23-27 Gt CO_2 per year, or at half the BASE scenario's level of emissions in 2050 (Figure 5.6).

Figure 5.5

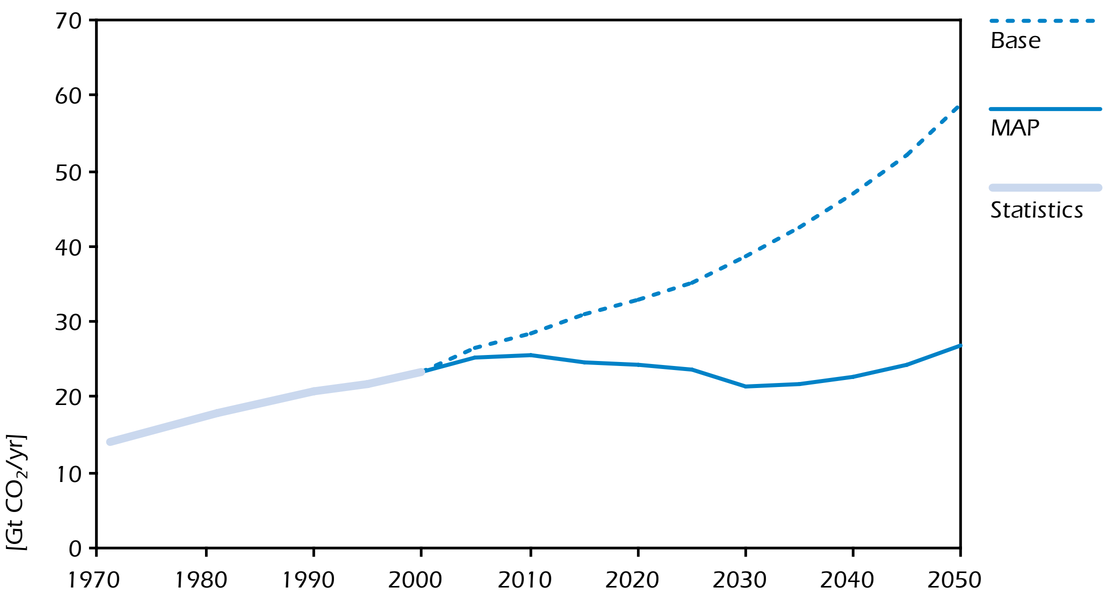
Primary energy mix in the MAP scenario



Key point: An incentive of USD 50/t of CO_2 results in higher renewable energy demand and lower coal demand

Figure 5.6

Global CO_2 emissions (BASE and MAP scenarios)



Key point: Emissions can be stabilised if an incentive of USD 50/t of CO_2 is introduced

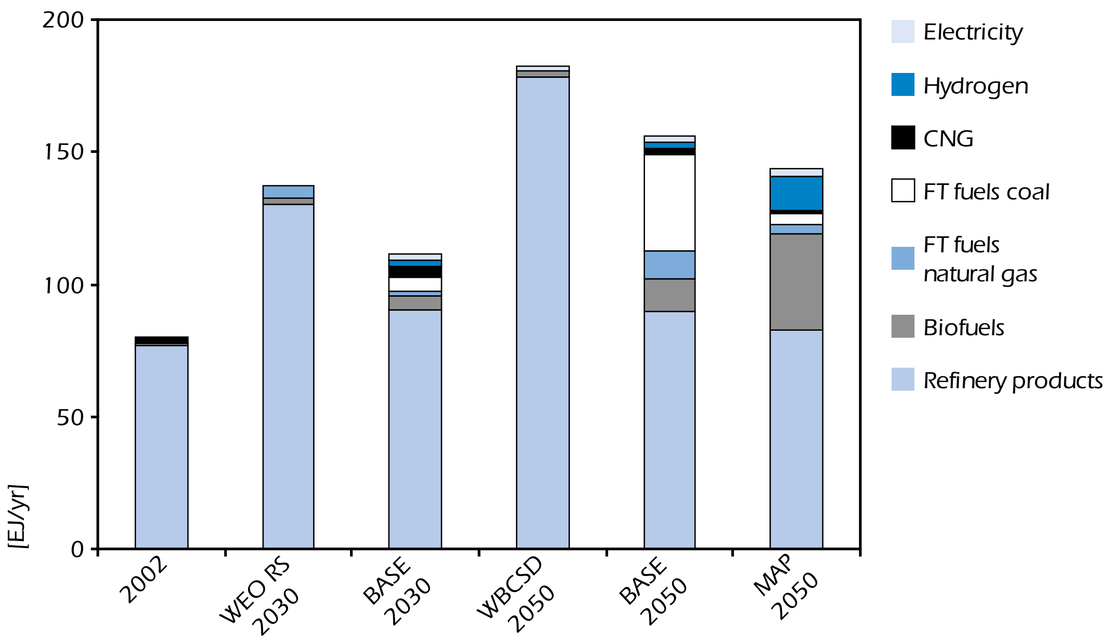
Results for the transport sector

Figure 5.7 presents the fuel demand of the transport sector in the BASE and MAP scenarios, in the IEA *World Energy Outlook* (WEO 2004) Reference Scenario, and in the World Business Council on Sustainable Development *Mobility* 2030 study (WBCSD, 2004). The time horizon of the WEO 2004 is 2030, while the WBCSD study extends the analysis to 2050. The WEO 2004 represents the most recent IEA projection. The WBCSD study was jointly developed by the IEA and the major oil and car companies, and provides a benchmark for 2050. It includes incremental improvements in internal combustion engine vehicles (ICEVs) technology, but no substantial use of hybrid vehicle technology. Hybrids are considered in the BASE scenario. Thus, the transport sector fuel demand in the BASE scenario is 14% lower than the WBCSD demand in 2050. In the BASE scenario, hybrids represent 29% of all passenger cars and light/medium-size trucks by 2050, and result in significant efficiency gains.

In the BASE scenario a significant change occurs in the fuel supply mix between 2030 and 2050. At this time, ethanol and synfuels from the Fischer-Tropsch synthesis of coal and gas all increase considerably, while the output of conventional refinery products remains more or less constant. This scenario seems to be consistent with the WEO 2004 taking into account a possible conventional oil production peak in 2028-2032 (IEA 2004a, p. 102). In this case, if demand for transportation fuel keeps rising, then beyond 2030 alternative fuels could rapidly gain market share. This result suggests that energy-security concerns alone do not necessarily result in significant hydrogen and fuel cell use. Other fuels can replace oil at a lower cost if climate change concerns are not a constraint.

Figure 5.7

Transport sector fuel demand by scenario



Source: IEA, 2004a and WBCSD, 2004.

Key point: Continued growth, but a trend away from conventional oil

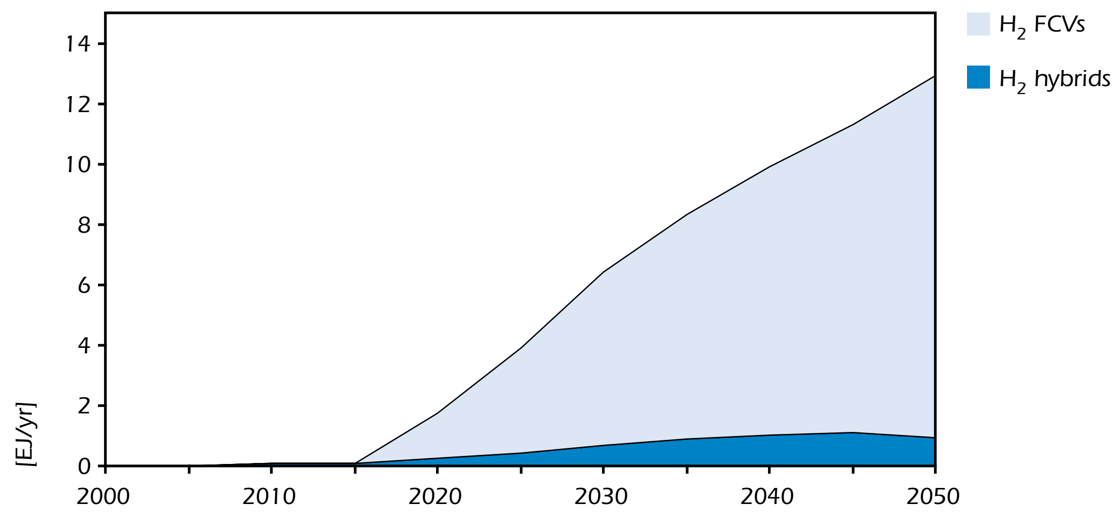
If a CO_2 reduction incentive is introduced (MAP scenario), then the context changes significantly, and compared to the BASE scenario, a further 6% efficiency gain occurs. The use of oil products is virtually unchanged from the BASE scenario. However, the role of biofuels and hydrogen increases significantly at the same time as that of FT fuels from coal and gas declines. This can be explained by the fact that FT fuels do not result in a reduction of tailpipe emissions, even if CO_2 is captured and stored during their production (Gielen and Unander, 2005). As the level of conventional oil demand in the MAP scenario is only slightly lower than in the BASE scenario, the MAP fuel mix does not necessarily represent an improvement in terms of energy-security. But this depends critically on the significant expansion of FT synfuels in the BASE scenario and its mitigating effect on crude oil supply, which is uncertain. Having said this, the result of this analysis shows very clearly that while energy-security concerns alone do not necessarily imply a switch to hydrogen and fuel cells, climate policies (represented by CO_2 incentives) seem to ensure that these technologies do take off, under the technology assumptions used in this study.

It is worthwhile to note that a USD 50/t of CO_2 incentive to reduce emissions translates into USD 0.12/l of gasoline. It may come as a surprise that such a limited price increase has such a significant impact, given the recent fuel price increases at the pump. However, one must allow for the fact that the model does not account for uncertainty and risk, and assumes perfect foresight. As a consequence, small price advantages can result in major change, while in reality there may be less significant impact. In such a context 12 US cents per litre does represent a significant price increase and will change consumer decisions. But if investors use conservative oil price projections and neglect CO_2 policy prospects in their decisions, the actual effect may be less significant.

In the MAP scenario, hydrogen use increases significantly from 2020 onward to reach 15.7 EJ in 2050. Some 82% of this hydrogen (12.9 EJ) is consumed in the transport sector. Initially, hydrogen hybrid vehicles play a role (0.1 % of the road vehicle market in 2015), while from 2020 onwards FCVs dominate (Figure 5.8). By 2050, hydrogen vehicles account for 27% of the vehicle stock.

Figure 5.8

Hydrogen use in the transport sector, 2050 (MAP scenario)



Key point: Hydrogen is mainly used for FCVs.
Hybrids play a key role in the transition

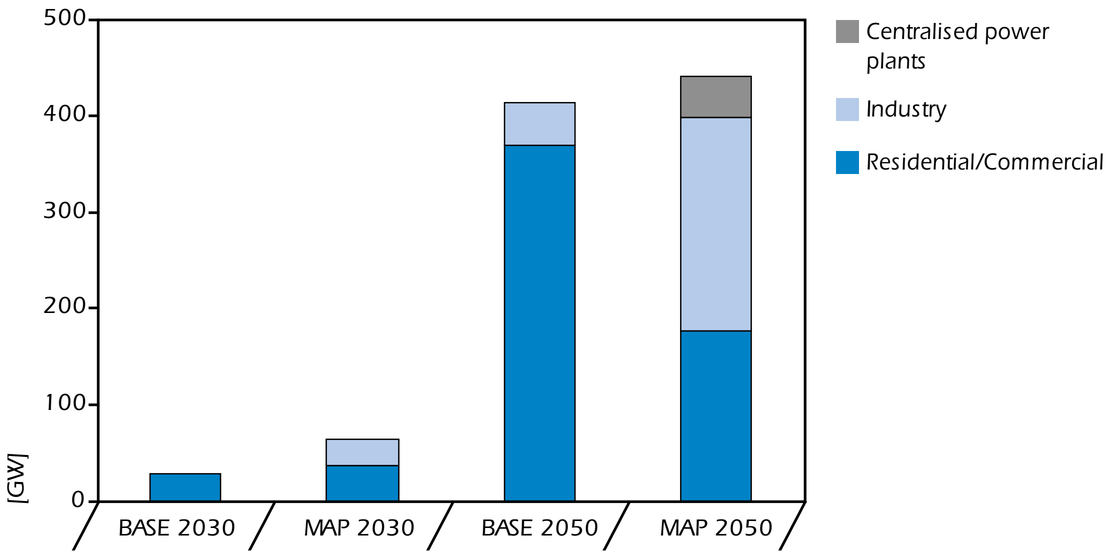
Note that a moderate amount of hydrogen can fuel a significant number of vehicles, which is a consequence of the high efficiency of FCVs. The regional shares of hydrogen in the transport fuel mix vary considerably, from zero in most developing countries to 24% in the USA. This can be explained by a combination of regional factors, such as market size, annual mileage, discount rate, availability of new technology over time and natural resource endowment. Perhaps surprisingly, no significant penetration of hydrogen buses occurs in the MAP scenario. However, this is explained by the fact that some 20% of total diesel is derived from biomass in this scenario and diesel hybrid buses are the technology of choice. In line with expectations based on technology cost data, hydrogen is not used for airplanes, ships and trains. However, MCFC fuel cells are introduced for ships.

Results for stationary applications

In both the BASE and MAP scenarios, the use of fuel cells in stationary applications is relatively limited in 2030 at 30-60 GW (Figure 5.9), but increases rapidly from that point to reach 450 GW in 2050 (5% of total electricity generation capacity). They are widely used in decentralised heat and power production in the residential, commercial and industry sectors. However, their use for the centralised production of electricity is limited. Natural gas fuel cells play an important role (Figure 5.10), with only a limited role for coal-gas and hydrogen fuelled systems (less than 10% market share each). The fact that stationary fuel cells are selected in both the BASE and MAP scenarios suggests that they are robust niche-market technologies, which are competitive without policy assistance.

Figure 5.9

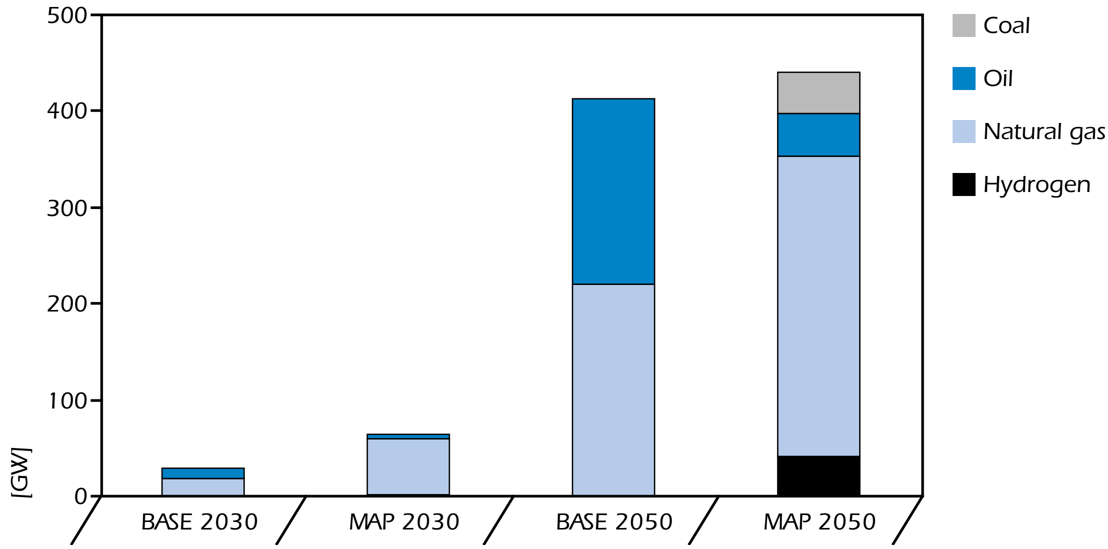
Stationary fuel cell capacity by sector (BASE and MAP scenarios)



Key point: Stationary fuel cell use is significant from 2025 onward

Figure 5.10

Stationary fuel cell capacity by fuel type (BASE and MAP scenarios)



Key point: *Natural gas-fired fuel cell systems dominate*

Chapter 6.

KEY DRIVERS FOR HYDROGEN AND FUEL CELLS: SENSITIVITY ANALYSIS

HIGHLIGHTS

- Hydrogen and fuel cells can play an important role in the future, but hydrogen demand is sensitive to a number of key parameters that are subject to significant uncertainties. These can be split into three areas: economic development and energy policies, competing fuels and energy technologies, and future development of hydrogen and fuel cells. The sensitivity analysis suggests that the uptake of fuel cells and hydrogen appears to be more sensitive to downside risks than upside ones. This implies that policy is crucial to exploiting the benefits of hydrogen and fuel cells.

- A limited number of factors have a positive effect on the future demand for hydrogen, while most factors have a negative effect. Significantly, relative to the MAP scenario (15.7 EJ H_2 in 2050), the sensitivity analysis indicates a maximum variation of ± 80% in hydrogen demand as a result of changes in the assumptions for individual parameters. A number of parameters have the potential to increase or decrease hydrogen demand by ± 30%. The combined effects of various parameters ("scenarios") may result in larger variations and are discussed in Chapter 7.

- Factors with a major positive impact are: higher levels of the CO_2 reduction incentive (*i.e.* more ambitious climate policies), favourable assumptions on FCV cost and efficiency, higher oil prices, low fuel taxes on hydrogen, development of nuclear energy and cheaper hydrogen production using nuclear heat, and timely development of infrastructure for centralised hydrogen production and distribution.

- Among factors that have a significant negative impact are: lower levels of the CO_2 reduction incentive (*i.e.* less ambitious climate policies), adoption of energy-security policies in the absence of a CO_2 reduction incentive, missing the most ambitious targets for FCV cost reduction, the effects of the "chicken-or-egg" transition problems, consumers using a higher "hurdle-rate" for buying cars, and extending the time horizon of the analysis to 2070. In contrast, the characteristics of competing technologies, although important, have a smaller impact.

- This analysis suggests the timely meeting of the most ambitious technology development targets for hydrogen and fuel cells (improved performance and cost reductions) is critical to their gaining an initial market share before other competing options take off. Delays in technical progress result in a "lock-in" effect by other technologies that are closer to market introduction, which then grow at the expense of hydrogen.

- Coal-based hydrogen and electricity cogeneration with CO_2 capture and storage (CCS) is of particular importance to the cheap centralised production of hydrogen in the long term. Strong developments in nuclear and renewable energy may also favour hydrogen and fuel cells. But depending on developments, they also expose hydrogen to competition from cheap and CO_2-free electricity and biofuels, which are alternative options to reduce emissions and enhance energy security.

Building on the MAP scenario discussed in Chapter 5, this sensitivity analysis aims to quantify the uncertainties that surround the model results. The uncertainties considered are the technical, economic and policy issues that can be analysed by ETP-type models. Other uncertainties, such as those due to industrial strategies, investment risk and public acceptance of new technologies are beyond the scope of this analysis. The sensitivity analysis indicates that a number of key parameters have a significant impact on the potential demand for hydrogen and fuel cells. How these parameters interact to reinforce or offset one another is the subject of the scenario analysis presented in Chapter 7. The sensitivity analysis in this chapter is crucial to understanding the conclusions of Chapter 7.

The key model inputs are split into government policies and economic parameters, hydrogen and fuel cell technology characteristics, and the characteristics of competing technologies and fuels. The goal of the sensitivity analysis is to quantify how sensitive the potential demand for hydrogen and fuel cells is to individual drivers in each of these three groupings. This will provide insights into the conditions that are needed for a successful transition to a hydrogen economy. The pre-selection of key parameters was provided by previous ETP studies (IEA, 2004c; Gielen and Podkanski, 2005; Gielen *et al.*, 2005) and by the results of the MAP scenario. Table 6.1 provides an overview of the drivers that were pre-selected and their values in the MAP scenario, as well as the range of values that were considered in the sensitivity analysis.

Government policies and socio-economic parameters

CO_2 reduction incentives

In Chapter 5, the MAP scenario assumes a global incentive to reduce CO_2 of USD 50/t of CO_2. This was chosen as a reference value, because it enables emissions stabilisation. However, the future of climate policies beyond the first commitment period of the Kyoto Protocol in 2008-2012 is unclear. Climate policies will depend on insights regarding the urgency needed based on emerging climate changes and on the outcomes of difficult international negotiations. If, and when, developing countries will act to curb their emissions is also unclear. Consequently, both the incentive level and its scope are matters that merit sensitivity analysis.

Two alternative incentive levels of USD 25/t of CO_2 (the MAP25 scenario) and USD 100/t of CO_2 (the MAP100 scenario) are examined in addition to the reference MAP scenario value of USD 50/t of CO_2. The impact of halving the incentive level in the MAP25 scenario is less than a 5 EJ hydrogen demand reduction (Figure 6.1). Hydrogen demand in the MAP25 and MAP scenarios follows a similar path, but with a five year delay in the case of the lower incentive. The MAP100 scenario roughly doubles the demand for hydrogen of the MAP scenario. These results confirm that the potential for hydrogen to contribute to reducing emissions is high, but that it can be limited by competition with cheaper options to reduce emissions and by policy measures that do not assign an appropriate value to avoiding emissions. However, many studies suggest that the damage caused by a tonne of CO_2 to the environment and human health should be valued at less than USD 50/t of CO_2 and that a significant potential exists for reducing greenhouse gases through land-use management at a cost well below USD 50/t of CO_2.

In the MAP scenario, the CO_2 emissions path is consistent with the stabilisation of CO_2 in the atmosphere at a level of 550 ppm (Figure 6.2) during this century, based on the IPCC scenarios (IPCC, 2001). Under the MAP25 scenario, emissions would continue to rise and are not consistent with the stabilisation of CO_2 concentration. The MAP100 scenario is the only scenario where global emissions decline significantly below 2000 levels. The MAP100 scenario is consistent with the stabilisation of CO_2 in the

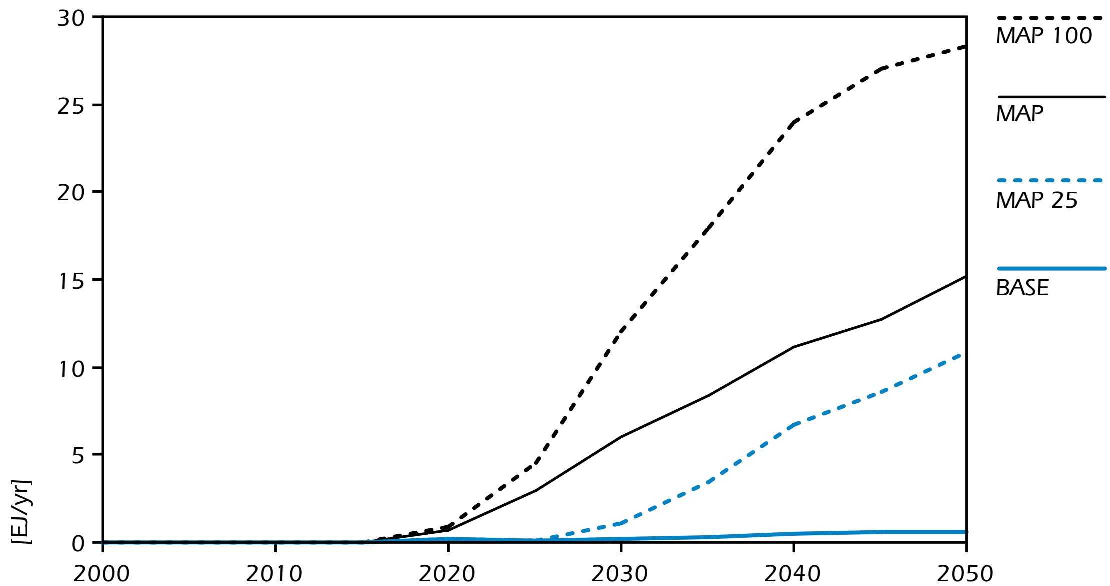
Table 6.1

Overview of the ETP sensitivity analysis

Parameters	The MAP reference scenario	Sensitivity level and range
Policies		
CO_2 incentive	USD 50/t of CO_2	USD 0, 25 or 100 /t of CO_2
CO_2 policy scope & timing	World wide. Starting in 2005.	Only countries that have ratified the Kyoto Protocol, starting in 2020.
Energy-security policies	Implicit in the CO_2 incentive.	A maximum oil import dependency of 33%.
Market structure	Government guarantees, soft loans and information campaigns lead to low "hurdle-rates" for alternative vehicles. High "hurdle-rates" for residential and commercial sector investment decisions.	Liberalised market with risk-aversion and lack of consumer information, resulting in high "hurdle-rates". Government guarantees, soft loans and information represented by "low-hurdle" rates.
Fuel tax regime	Tax for H_2 and other alternative fuels increases to 75% of gasoline tax by 2050.	Tax for H_2 and other alternative fuels increases to 100% of gasoline tax by 2050. No fuel tax for H_2. Tax for other alternative fuels increases to 75% of gasoline tax by 2050.
Fuel prices	Average oil price 2030-50 USD 30/bbl. Natural gas price of USD 3-5/GJ.	Oil prices of USD 40/bbl. Natural gas prices of USD 4-6 /GJ.
Planning time horizon	2050	2070
Competing options		
Nuclear electricity	Capacity growth is constrained by acceptance issues in OECD and limited to 5% per year in developing countries.	Growth is determined by economics in OECD and limited to 10% per year in developing countries.
Nuclear H_2 production	Growth is constrained by acceptance issues in OECD and limited to 5% per year in developing countries.	Only cost-based economic competition, 30% lower investment cost for nuclear reactors and higher efficiencyfor S-I H_2 production cycle.
Renewable energy	Low learning rates and missed deployment targets result in limited cost reductions.	High learning rates and ambitious policy targets result in more cost reduction
Biomass	Primary biomass potential 200 EJ per year.	Primary biomass potential 100 EJ per year
H_2 and FC technologies		
IGCC availability	Coal-fired IGCC available for electricity and H_2 cogeneration.	IGCC not available for electricity and H_2 cogeneration.
CO_2 Capture and Storage	CCS available.	CCS not available.
FC cost	FC system cost: USD 60/kW.	FC system cost: USD 105/kW.
H_2 storage	H_2 storage cost: USD 225/kg (700 bar).	H_2 storage cost: USD 500/kg (700 bar).
FC durability	No FC replacement during vehicle life.	One FC replacement during vehicle life.
FCV power	FCV capacity equivalent to ICEV.	FCV capacity 25% lower than ICEV.
FCV efficiency	FCVs are 1.82 times more efficient than an ICE.	FCVs are 2.95 times more efficient than an ICE.
H_2 cost decline	H_2 technologies reach their lowest cost level by 2025.	H_2 technologies reach their lowest cost level by 2015 or 2040.
FCV cost decline	FCVs reach USD 65/kW by 2025.	FCVs reach USD 65/kW by 2015.
Transition issues	Optimal size hydrogen supply infrastructure at once. Centralised H_2 production considered.	A gradual up-scaling from decentralised to centralised H_2 supply. Centralised H_2 production not considered.

Figure 6.1

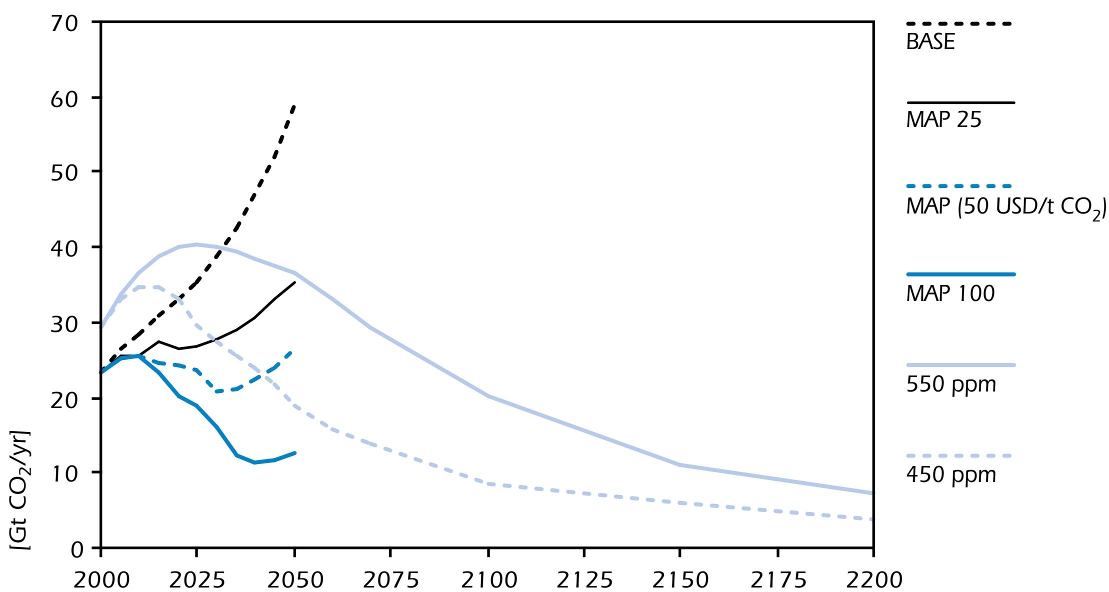
Hydrogen demand under different policy incentive levels



Key point: *Higher incentives result in increased hydrogen use*

Figure 6.2

Energy-related CO_2 emissions at various CO_2 incentive levels and scenarios consistent with 550 ppm and 450 ppm



Source: IEA and IPCC, 2001.

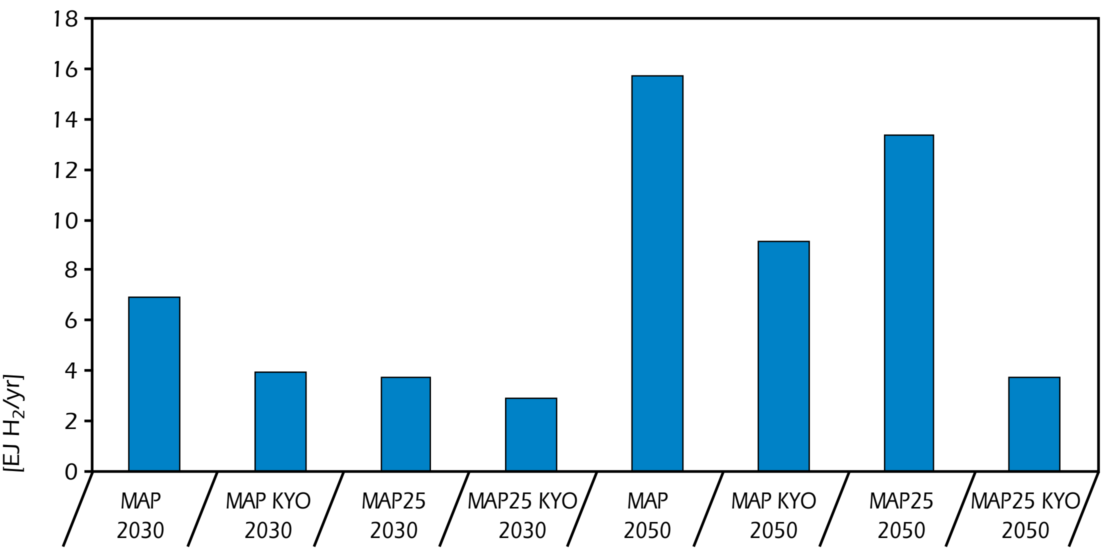
Key point: *An incentive of USD 50/t of CO_2 could be in line with stabilisation of CO_2 concentration in the atmosphere at 550 ppm* atmosphere at 450 ppm.[16] It is difficult to define fixed emission paths to 2050 to stabilise CO_2 concentration in the atmosphere. Decision making should be balanced between the cost of the intervention and the risk of major climate change.

CO_2 policy scope and timing

In order to asses the impact of potential regional differences in climate change policies and incentives, the MAP scenario is compared to a scenario called the "MAP KYO" scenario, where only countries that have ratified the Kyoto Protocol eventually reach an incentive level of USD 50/t of CO_2. The other countries, including the United States and Australia, are assumed to only apply an incentive of USD 10/t of CO_2. The exercise was also repeated for a value of USD 25/t of CO_2 for Kyoto ratifiers, thus making the MAP25 scenario directly comparable with a MAP25 KYO scenario. These scenarios suggest that while efforts in the countries that ratify the Kyoto Protocol would suffice to bring hydrogen to the market, the introduction of hydrogen benefits more from globally applied and ambitious CO_2 incentives (Figure 6.3). If non-Kyoto countries do not adopt CO_2 policies, they have fewer reasons to use biofuels. Biofuel may be exported to Kyoto countries and oil products may be used instead (*i.e.* a "carbon leakage" effect). However, this effect is of secondary importance in terms of hydrogen use in Kyoto countries. The MAP KYO scenario shows 42% less hydrogen use in 2050 and the MAP25 KYO scenario shows 76% lower hydrogen use.

Figure 6.3

The sensitivity of global hydrogen use to the incentive level and coverage (MAP, MAP25, MAP KYO and MAP25 KYO scenarios)



Key point: Climate incentives only in countries that have ratified Kyoto considerably reduces hydrogen demand

16. The IPCC emissions path curves consistent with stabilisation at 550 ppm and 450 ppm are higher than the ETP curves in the base year of 2000. The difference in the base year level of emissions is accounted for by CO_2 emissions from de-forestation, which are not included in the ETP model.

In order to assess the incentive timing issue, the introduction of the CO_2 reduction incentive in the MAP scenario was delayed by 15 years to 2020. In this case, somewhat surprisingly, hydrogen use from 2030 onwards is higher than in the MAP scenario, ending 3% higher in 2050. Actually, hydrogen and fuel cell R&D needs time to achieve significant cost reductions, so that if significant "blanket" incentives are introduced at an early stage, other technology options are chosen. The resulting "lock-in" effect limits hydrogen's expansion in the long term. Delaying the introduction of the incentive results in higher emissions in the period 2030-2050. This implies that the early uptake of hydrogen (in the next 20 years) is needed to generate the greatest reduction in emissions.

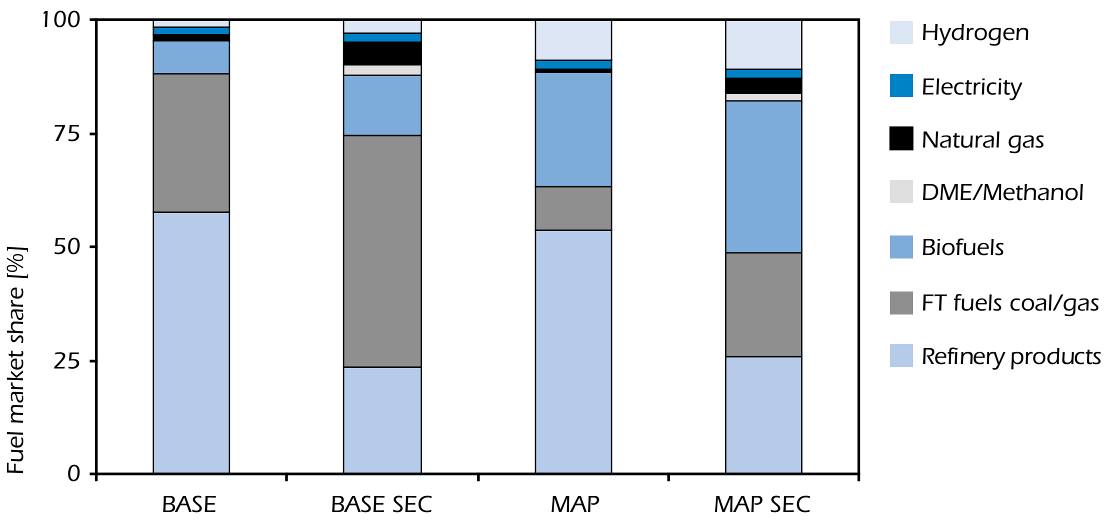
Energy-security policies

In addition to the CO_2 reduction incentive, other measures aimed at reducing the dependence on oil are represented by setting an upper limit on the share of transport fuels supplied from imported oil. This constraint reflects a range of policies and measures aimed at improving energy-security. While such measures would undoubtedly vary by region, in the sensitivity analysis an identical constraint is set across all model regions. It is assumed that the constraint is gradually introduced from 2005 onwards and attains its maximum level in 2050, when at most, 33% of transportation fuels may come from imported conventional oil. The model then chooses from alternatives such as biofuels, CNG, hydrogen, electricity, methanol/DME, indigenous non-conventional and conventional oil production, and FT synfuels from coal, natural gas and biomass to supply the remaining 67% of transport fuels.

The results (Figure 6.4) suggest that such additional energy-security policies would have a substantial impact when applied in the BASE scenario (called the BASE SEC scenario) . The impact is much more limited when they are applied in the presence of CO_2 incentives (the MAP SEC scenario). In both cases, the additional security policy would have a small positive effect on hydrogen demand. In the MAP SEC scenario hydrogen demand increases by 3% in 2050, but other cheaper fuel and fuel

Figure 6.4

Fuel shares in the transport sector with and without energy-security policies, 2050



Key point: *Additional energy-security policies result in a limited additional uptake of hydrogen, as other cheaper options exist* efficiency options are selected to meet the lion's share of the requirements of the security goal. Notably, additional synfuels from biomass, gas and coal are introduced. The result confirms that energy-security policies alone do not necessarily result in a substantial switch to hydrogen, because other cheaper options exist to achieve energy security and diversification. However, increased use of FT fuels may result in substantially higher well-to-wheel CO_2 emissions.

Market structure

The MAP scenario assumes consumers' discount rates for investment in the transport sector that range from 3% per annum in Japan to 9.7% per annum in the FSU (in real terms). Although, this is consistent with capital borrowing by companies, it is a model simplification. Consumers generally face higher costs of borrowing than do companies. Certain consumers look at the full life-cycle cost, while others focus on the investment cost only. The latter case is equivalent to an infinitely high discount rate. This is often reflected in economic studies through a so-called "hurdle-rate". To reflect the uncertainty in what discount rates consumers use, an alternative scenario assumes that "hurdle-rates" add 9% to the basic discount rate in the transport sector, thus giving a range of 12% to 18.7% per annum. This scenario of higher discount rates in the transport sector reduces hydrogen use significantly, from 15.7 EJ in the MAP scenario to 10.9 EJ in 2050.

For stationary fuel cells, the assumed discount rate differs by sector. Relatively low discount rates have been applied in the electricity sector (3% to 9.7% per annum) and in the industrial sector (7.5% to 14.3%). The discount rate in the residential and commercial sectors ranges from 12% to 28.2%. In the sensitivity analysis, this discount rate has been reduced to the same level as for the electricity sector (MAP LDR scenario). This resulted in a 33% increase in fuel cell capacity. The result suggests that the high cost of fuel cell systems can be a significant barrier for consumers. In fact, the problem may be even more severe if the owner and the tenant are different persons. The owner does not reap the benefits of efficiency measures and has no incentive to invest in capital-intensive equipment such as fuel cells.

Fuel tax regime

In the MAP scenario, fuel taxes for alternative fuels gradually increase from zero in 2005 to 75% of the gasoline tax in 2050. In the sensitivity analysis, the tax is assumed to rise over time to 100% of the gasoline tax in 2050. This translates into a 6% increase in hydrogen demand, because the tax increase reduces the competitiveness other alternative fuels more than for hydrogen, due to the higher fuel efficiency of FCVs. As a consequence, higher taxes result in a comparative advantage for hydrogen.

In a second sensitivity analysis hydrogen was exempt from all taxes. This model run resulted in 38% higher hydrogen demand in 2050 than in the MAP scenario and represents a scenario where hydrogen is particularly favoured by public policies. The results suggest that tax exemption would be particularly effective in high-tax regions such as Japan and Europe, where hydrogen use would increase three-fold. This instrument would be less effective in other regions with much lower fuel taxes. However, the impact of such a policy on government revenues would be important.

Fuel prices

Fuel prices are a key factor in determining the choice of energy technologies used and, as a result, the future levels of different emissions. While fuel prices may experience large fluctuations in the short term, the ETP model analysis is more concerned with average prices and long-term trends. It does not attempt to model the impact of short-term energy price volatility.

Oil prices in the BASE and MAP scenarios are in line with the long-term projections in the IEA WEO 2004, in which they rise steadily to reach USD 29/bbl (real 2000 prices) in 2030, at which level they stabilise. However, given the uncertainties regarding long-term supply availability and demand, different long-term oil price scenarios have been considered. The impact of higher prices has been assessed in the sensitivity analysis by varying long-term oil and gas prices. A Middle East oil supply curve twice as steep as in the MAP scenario has been considered, which results in a long-term average oil price of USD 35/bbl in 2030 and up to USD 40/bbl in 2050 (real 2000 prices).[17] The gas price has been varied accordingly. The higher oil and gas price assumptions are combined with limited expansion potential for non-conventional crude, FT-synfuels and other alternative fuels.[18] Only hydrogen was not constrained. This could reflect a situation where the uncertainty concerning future oil prices limits investment in capital-intensive synfuel production facilities, at a time when governments are actively supporting the development of a hydrogen economy.

Under these assumptions, hydrogen demand is 4.8 EJ (30%) higher than in the MAP scenario in 2050. This indicates an important sensitivity to fossil fuel prices, assuming the limited expansion potential of other alternative fuels. This model run represents a scenario where the economic, technical, environmental and security factors are favourable to hydrogen, but where government revenues are not compromised, as in the preceding sensitivity analysis on fuel tax exemptions. While fossil fuel prices themselves are not under the control of energy policy makers, higher taxes on fossil fuels could have a similar effect. However, the political feasibility of substantially higher taxes is also uncertain.

Planning time horizon

The ETP model's time horizon is from 2000 to 2050. Developments that occur after this date are not taken into account in the optimal investment path calculated by the model. Such "short-sightedness" can affect the results. For example, if oil production declines further after 2050, sensible energy policies would be taking such depletion into account before 2050, because a transition to a new energy system can take decades. Also, if post-2050 technology learning benefits are expected to be significant for a technology or fuel, such expectations might result in the increased use of these technologies or fuels in the period 2000-2050. This might have the impact of reducing or increasing the potential market for hydrogen and other options. To analyse such effects, the time horizon of the model has been extended to 2070, while leaving the other parameters at their 2050 levels.

The somewhat surprising result is a 43% decline in hydrogen demand in 2050 relative to the MAP scenario. The main reason is that oil prices in the 2020-2050 period are much higher (20-50%) if a 2070 time horizon is used. The model to some extent "sees" the long-term oil availability problem beyond 2050, and the higher oil prices in the period 2020-2050 facilitate earlier and widespread introduction of synfuels at a time when hydrogen and FCVs are still relatively costly. Once a large investment has been made, hydrogen has to "wait" for the next investment cycle ("lock-in effect"). The result suggests that, given the current state of hydrogen and fuel cell technology, a very rapid increase of oil prices would not benefit hydrogen, unless rapid technology advances takes place at the same time.

17. These values represent a 5-year average of high and low prices. During the second oil shock at the beginning of the 1980s oil reached a price level of more than USD 60/bbl (real 2000 prices), but in the second half of the decade the price dropped to about USD 20/bbl.

18. Previous analysis showed that only different OPEC behaviour does not result in a substantial price increase, as more synfuels from coal and gas are introduced. These fuels would become cost-effective at oil price levels between USD 30/bbl and USD 40/bbl (Gielen and Unander, 2005). The key uncertainty is how fast the production of these alternatives can expand. Continued uncertainty concerning oil price prospects may deter investments in capital-intensive synfuel production facilities.

If the oil price would have been kept constant, it is likely that this sensitivity analysis would have resulted in higher hydrogen use.

Competing technologies and fuels

Renewables

The future of hydrogen and fuel cells also depends on the development of competing technology options such as renewables. A key question for renewable energy relates to its potential availability and cost in the future. The cost of renewables is determined by the capital cost, as the primary energy source is usually free (wind, sun, etc.). Future capital costs are a function of current capital costs and technology learning (*i.e.* R&D learning and "learning-by-doing" in commercial settings). Future cost levels are uncertain due to the uncertainty about learning rates. Factors that affect the accuracy of the cost estimates are little or no cost history (*e.g.* PV and fuel cells), highly site-specific installation costs (*e.g.* hydropower, biomass and geothermal), and market dynamics that obscure the relation between capacity and investment cost (*e.g.* PV and CCGTs). The learning rates used in this study are in line with the range found in the literature (Cody and Tiedje, 1997; Neij, 1997; Harmon, 2000; IEA, 2000; Junginger *et al.*, 2005).

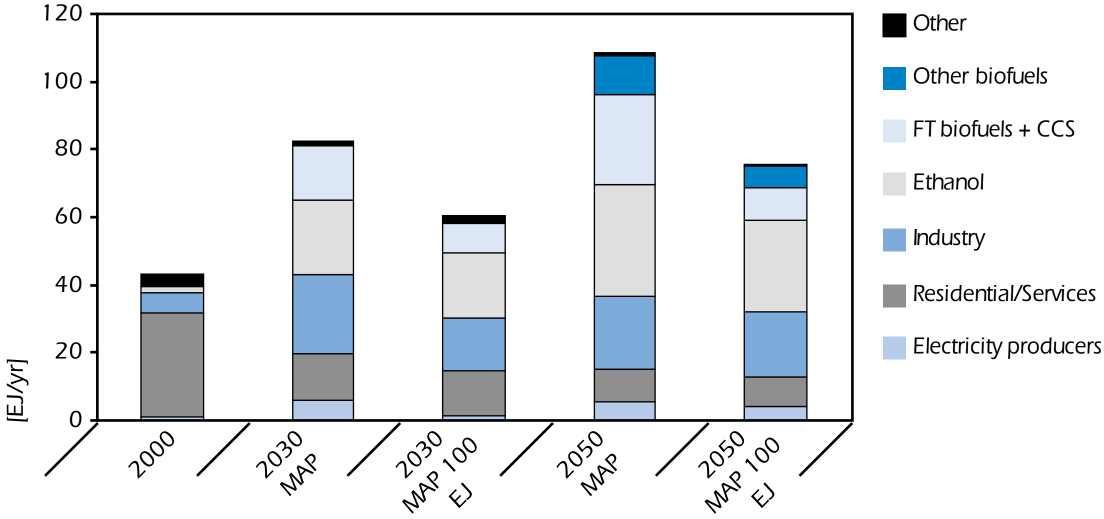
In the MAP scenario, investment cost reductions for renewables are based on the cumulative capacity that follows from the deployment path in the WEO 2004 Reference Scenario, in combination with technology learning rates. Investment costs decline by a fixed factor for each doubling of the installed cumulative capacity (IEA, 2000). In the sensitivity analysis (MAPREN scenario), current and prospective policy initiatives for the deployment of renewables are added to the ETP model based on the WEO 2004 Alternative Scenario up to 2030. Beyond 2030, actual investments are determined by the model based on their cost. The sensitivity of hydrogen to the development of renewables has also been looked at in two increasingly optimistic scenarios, where cost reductions are achieved through even higher market uptake. The potential costs and availability of renewable energy need to be considered in tandem. Although cheap renewable options exist today, their potential in terms of energy supply is limited. However, renewables' contribution could be increased if more expensive renewable options achieve cost reductions.

The result of these assumptions is that the cost of renewable electricity generation declines faster over time and hydrogen demand is 5% less in 2050 than in the MAP scenario due to greater electricity generation from renewables. Much of this reduction is due to lowered capacity of FutureGen-type coal-fired IGCC power plants that cogenerate electricity and hydrogen, since the use of renewables expands at the expense of coal.

Another scenario explores in more detail the role of biomass and biofuels. Primary biomass in the MAP scenario increases from 0 to 200 EJ per annum in 2050, while in this sensitivity analysis the biomass availability rises to only 100 EJ per annum. The reduced potential for biofuels translates into an increased demand for hydrogen of 9% in 2050. The lower availability of biofuels is also balanced by increased use of other synfuels and refinery products. It is important to note that biofuels and hydrogen are not strictly alternative options, as they do not compete head-to-head. Hydrogen does not directly compete with diesel in the medium and heavy freight sector, shipping, and aviation sectors. Synthetic diesel from biomass is a better CO_2-free alternative in this market segment. A further result of the analysis is that biofuels production is a higher value use of biomass than electricity production (Figure 6.5). This is confirmed in the MAP scenario with a 200 EJ primary biomass potential, as well as in the sensitivity analysis with a 100 EJ biomass potential in 2050.

Figure 6.5

End-use of primary biomass under different biomass availability scenarios



Key point: Biofuels may become the most important use of primary biomass

Nuclear power

If cost optimisation is the only constraint, nuclear power can be an attractive option for reducing CO_2 emissions. This is based on investment costs (including waste treatment and decommissioning) declining from USD 2 200/kW in 2000 to USD 2 000/kW in 2040. In the MAP scenario investment in nuclear energy is constrained to represent public acceptance, the difficulties with waste treatment and proliferation issues. In the sensitivity analysis, investment in nuclear is unconstrained in OECD countries and the maximum annual growth rate in developing countries is increased from 5% to 10%. Under these assumptions, nuclear's share of world electricity generation increases significantly to reach about one-third of total electricity production. However, the reduced electricity production from fossil fuels reduces the potential for electricity and hydrogen cogeneration in IGCC plants. This affects global hydrogen production, which is 19% lower in 2050 than in the MAP scenario.

However, the implications of a nuclear renaissance could also be positive for the use of hydrogen. In the MAP scenario high-temperature nuclear reactors which use the sulphur-iodine cycle to produce hydrogen are assumed to cost USD 60/GJ H_2 (USD 1 800/kWth) and have annual O&M costs of USD 6/GJ H_2. In the sensitivity analysis, this investment cost is assumed decline to USD 1 250/kWth, and the fixed O&M cost to decline USD 3/GJ H_2. These assumptions are designed to examine the effect of the successful development of a low-cost reactor design and higher efficiencies for the S-I cycle (greater than 50%) due to higher temperatures.

Without public acceptance constraints and other issues, these assumptions lead to a prominent place for nuclear production of hydrogen from 2035 onward. Its share increases to 50% of total hydrogen production in 2050, while total hydrogen production is 5.7 EJ (36%) higher than in the MAP scenario. This additional growth is concentrated in China, and it takes place between 2030 and 2050. The impact on other regions is limited. The reason why this option is important for China is that there are few other economic options, as coal-based hydrogen production at FutureGen-type plants is only introduced from 2040 onward and natural gas feedstock availability for hydrogen production is limited. These modelling assumptions need further analysis.

Hydrogen and fuel cell technologies

Technology availability

The projected contribution of hydrogen to energy supplies is, to a large extent, based on technologies that are not yet commercially proven. If only proven technologies are considered, the role of hydrogen might be significantly less. The goal of this sensitivity analysis is to quantify the impact this restriction might have.

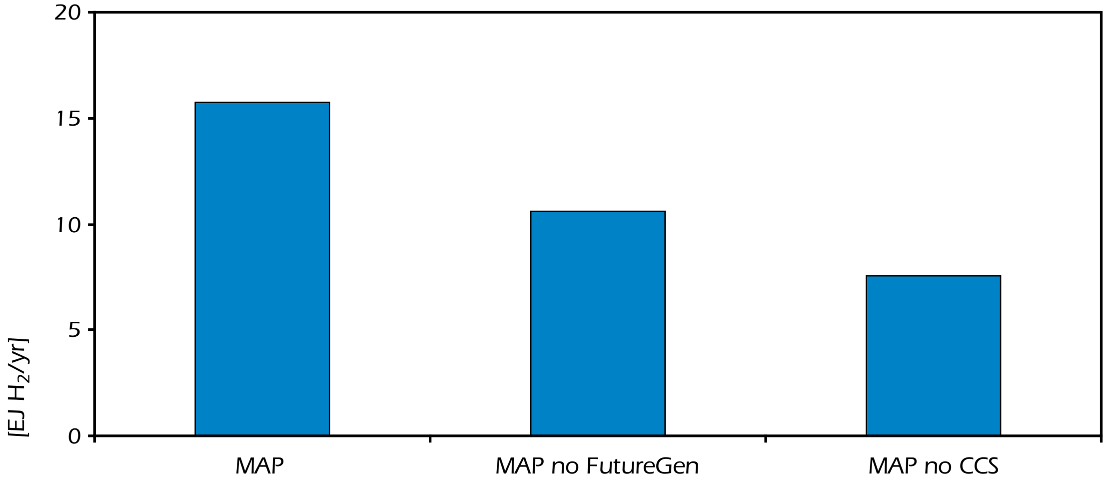
Hydrogen production from fossil fuels with CO_2 capture and storage, particularly the cogeneration of electricity and hydrogen in IGCC plants, plays a significant role in the MAP scenario. To assess the sensitivity of the model results to the availability of IGCC plants and CCS technologies, two separate scenarios were examined. The first scenario excluded the cogeneration of electricity and hydrogen in IGCC plants, while a second, more restrictive scenario also removed all CCS technology options. This could reflect a situation where underground CO_2 storage is not pursued any further due to emerging safety problems or poor public acceptance of this technology option.

Figure 6.6 shows the hydrogen production for the MAP scenario and the two alternative cases. Total hydrogen demand is 33% to 52% lower in 2050 than in the MAP scenario. This indicates that CCS is a key enabling technology in a transition to the CO_2-free production of hydrogen, which in turn shows the importance of fossil fuels for the production of hydrogen in the 2050 time frame. The decline in hydrogen demand is accompanied by a significant change in the technology mix. This result is somewhat of a surprise, because the hydrogen fuel cost constitutes a relatively minor part of the overall cost of the hydrogen energy system, including the cost of FCVs. The availability of the coal-based synfuel cogeneration units is a further uncertainty for total hydrogen use.

The absence of CCS technologies also has an impact, in this case positive, on the prospects for stationary fuel cells. Decentralised fuel cell plants are unlikely to be candidates for CCS. The absence of CCS technologies therefore removes some of the advantages that centralised technologies with CCS have over stationary fuel cells. Stationary fuel cells therefore become relatively more attractive as decentralised fuel cell use is 20% higher than in the MAP scenario in 2050.

Figure 6.6

The sensitivity of hydrogen to the availability of FutureGen Plants and CCS, 2050



Key point: *CCS is a key enabling technology for hydrogen*

Technology performance

The sensitivity analysis of technology performance focuses on the role of PEM fuel cells for transport. Six separate scenarios look at six different performance issues that could affect the demand for hydrogen. The first scenario assumes that two fuel cell stacks will be needed during the life of the vehicle, rather than just one, raising costs significantly in the early years. However, the cost increase is less than twice the fuel cell cost due to discounting. It is assumed that the vehicle cost at the moment of acquisition increases by half of the fuel cell cost. This reflects a fuel cell that is replaced after 5-7 years at a discount rate of about 10%.

The second sensitivity analysis assumes less technology learning for fuel cells. The minimum cost level is reached 15 years later and the minimum cost level is USD 35/kW higher than in the MAP scenario (Figure 6.7). The third sensitivity analysis assumes that the fuel cell power of an FCV does not necessarily have to match the power of a comparable ICE, as electric engines in FCVs have superior efficiency and acceleration performance compared to ICEs. Therefore a 25% lower capacity is assumed for FCVs to have the same market acceptance.

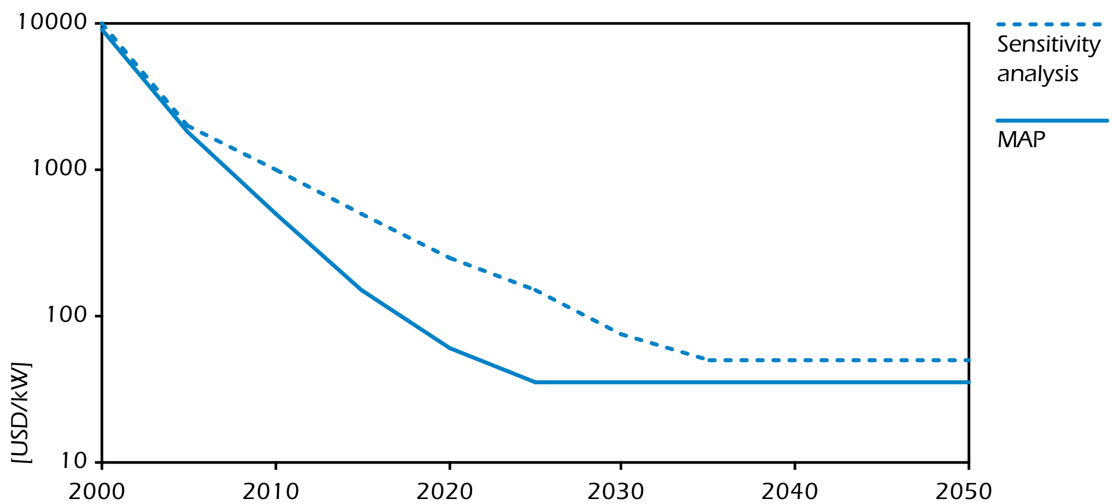
These assumptions have significant, individual impacts on hydrogen use. The result of the first analysis is to reduce hydrogen demand by 17% below the MAP scenario in 2050. The result of assuming less technology learning is more dramatic and reduces hydrogen demand by 80% in 2050. The result of the third analysis is an increase in hydrogen demand in 2050 of 6% over the MAP scenario.

The fourth scenario is a variation of the second, as the minimum cost level of PEM fuel cells for FCVs is set at the same level as in the MAP scenario, but this cost floor is reached 20 years later. This sensitivity analysis reflects a delay in technology development rather than a different final level of costs. This could be due to an uncertain policy environment, increased focus on competing options or delayed FCV development. The results show a reduction in hydrogen use of 26% in 2050.

The fifth scenario looks at a more optimistic cost path that has been projected by some car manufacturers (*e.g.* PEM fuel cell stack cost of USD 30/kW by 2010). An optimistic estimate of USD 65/kW for the full drive system (stack, peripherals, storage, etc.) by 2015 was considered.

Figure 6.7

Alternative assumptions for PEM FCV cost reductions



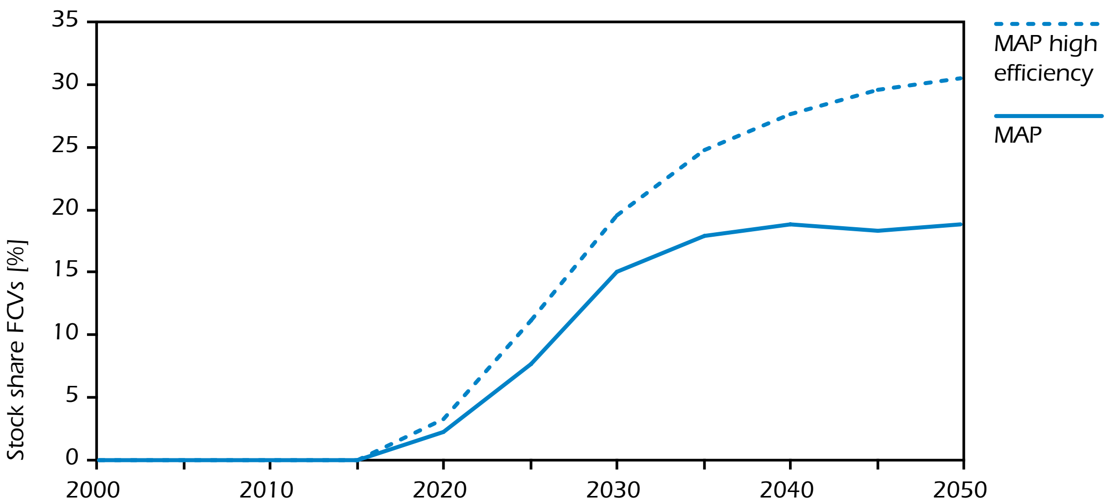
Key point: FCV cost reduction projections vary widely

This resulted in hydrogen demand in the 2020-2030 period being about 1 EJ per annum higher than in the MAP scenario, and 0.5 EJ higher in 2050.

The efficiency gain of FCVs over ICEVs was also considered as a sufficiently important issue for sensitivity analysis. The default assumption in the ETP model is a relative FCV efficiency of 1.82, compared to the advanced ICE. The US-DOE uses a relative efficiency factor of 2.27 for 2010 that increases to 2.95 in 2050. Japanese government sources also estimate a higher efficiency potential than the ETP assumption. A comparison of FCV penetration under the MAP scenario and the US-DOE efficiency assumptions is shown in Figure 6.8. Data refer to the total of three market segments: passenger cars, SUVs and light trucks, and delivery vans and medium trucks. Under the optimistic set of efficiency assumptions, the FCV stock is 60% greater. In terms of hydrogen use, the impact is an increase of 1.1 EJ (7%). The reason is that more efficient FCVs require less hydrogen.

Figure 6.8

Impact of FCV efficiency assumptions on their stock share (passenger cars, light/medium sized trucks and delivery vans)



Key point: *Assuming a 60% higher efficiency for FCVs increases their share by 60% in 2050*

Transition issues

The MAP scenario does not account for the potentially problematic transition issues that face hydrogen. As a consequence, the model chooses to immediately opt for the least-cost supply option of centralised large-scale hydrogen production with a pipeline distribution system. However, in reality, a transition period may be needed during which decentralised production is used. The necessity of a transition period has been included in a model scenario to assess the sensitivity of hydrogen to this problem. In it, only the decentralised production of hydrogen from electrolysis and natural gas reforming can be used initially. Once market uptake gains momentum, a transition to centralised production can then gradually take place. The details of this modelling approach are elaborated in Annex 1.

The sensitivity analysis shows that when transition issues are considered in the model (called the MAP CHE scenario), hydrogen demand is 42% lower than the MAP scenario in 2050 (Figure 6.9). This result suggests that transition issues are an important determinant of hydrogen's long-term market share. However, the magnitude of this result is sensitive to the assumed rate at which the large-scale supply of hydrogen expands.

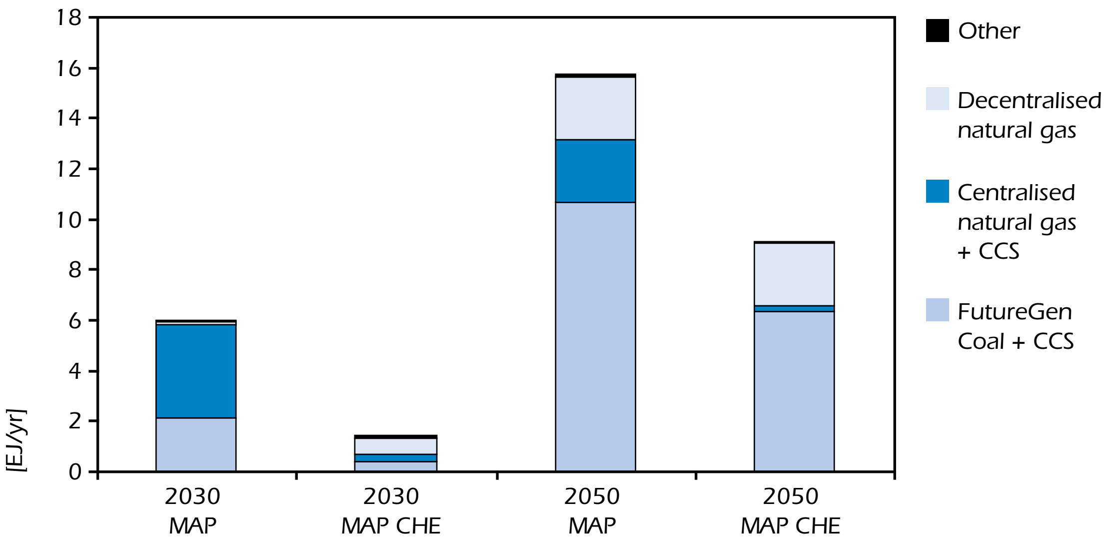
Although this approach accounts for one of the transition problems hydrogen faces, namely the difficulty in developing supply infrastructure, it does not account for the investment risk of mass producing fuel cells, electrolysers, etc. This is also a significant transition issue and is needed to bring costs down to competitive levels. This risk poses a different kind of transition problem, which is beyond the scope of the ETP model. However, it could in principle also reduce the prospects for hydrogen use.

A second sensitivity analysis excluded centralised production completely. For example, the development of a hydrogen pipeline system may face planning problems in urban areas and be too expensive for rural areas. In this case, the sensitivity analysis shows a 54% decline in hydrogen demand in 2050 compared to the MAP scenario. Interestingly, electrolysis emerged in this scenario as an important supply option, suggesting that electrolysis may have an important role in regions without centralised hydrogen production.

Somewhat in contrast with the previous assumptions on centralised hydrogen production, a further model run has been considered in which the distribution cost for hydrogen in the residential and commercial sectors has been halved with respect to the MAP scenario. In the reference assumptions these costs gradually decline over time from USD 100/GJ to USD 40/GJ of capacity and are so substantial that they could prevent the major uptake of hydrogen, either for PEM fuel cells or in existing burners. The result of the drastic cost reduction is a 1.3 EJ (8%) increase in hydrogen demand in 2050. The additional hydrogen is used mainly for residential fuel cell systems. The sensitivity analysis shows that hydrogen distribution costs pose an important barrier to the introduction of hydrogen in stationary uses in the residential and commercial sectors.

Figure 6.9

Hydrogen production mix (MAP and MAP CHE scenarios)



Note: The MAP CHE scenario delays the use of centralised production until after significant demand emerges, allowing for the chicken-or-egg hydrogen transition issues.

Key point: *Transition issues reduce hydrogen demand and affect the production mix*

Using off-peak electricity for hydrogen production

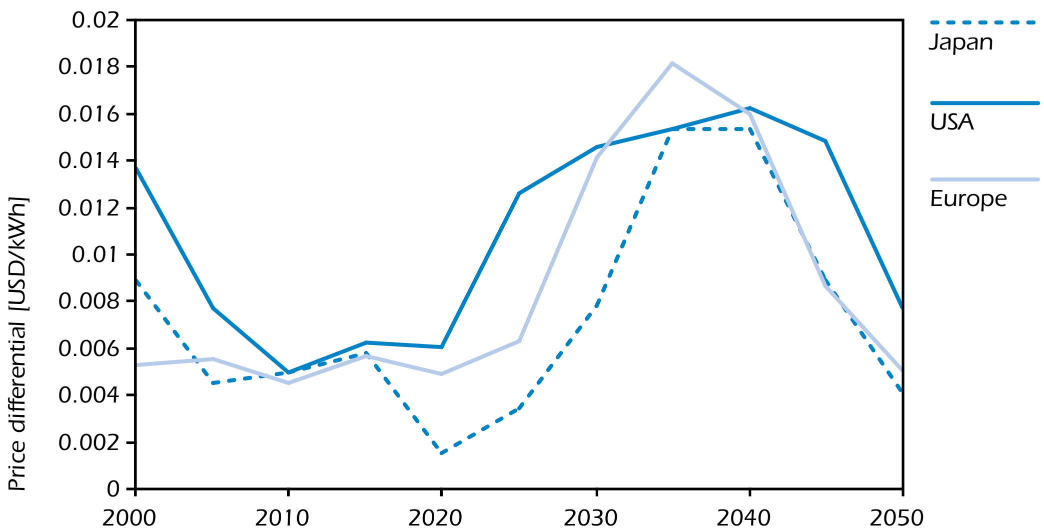
High electricity costs pose a challenge for cost-effective hydrogen production from electrolysis. One way to make electrolysis economically more attractive is to use low-cost off-peak electricity. The electricity price is much lower in periods of low demand, because the marginal production costs are low. In the ETP model this is reflected in lower electricity shadow prices (marginal costs) at night.

However, the attractiveness of using off-peak electricity for overnight electricity storage using hydrogen depends on the cost of production and the hydrogen storage cost. Given that the cost target for hydrogen storage systems in fuel cell vehicles is USD 150/kg, storage at refuelling stations is assumed to be around half this cost due to economies of scale. Typically 2 kg of hydrogen storage capacity is needed for 1 kg of delivered hydrogen. Assuming a 15% annuity, this translates into USD 0.5/GJ of hydrogen delivered.

*The difference between average electricity production costs and the night-time cost for three model regions is shown in Figure 6.10. The gap is between USD 0.001/kWh and USD 0.018/kWh. Assuming a 75% conversion efficiency into hydrogen (*i.e. *an optimistic estimate), this translates into a cost advantage of USD 0.6-6.7/GJ H_2. On average, the economic benefits of lower electricity cost would exceed the cost for the additional storage capacity needed by a factor of six. The cost reduction per GJ of hydrogen produced would amount to USD 3/GJ hydrogen. This could be sufficiently high to make electrolysers economically viable.*

Figure 6.10

Difference between the average electricity price and nightly electricity prices (MAP scenario)



Key point: The gap could be wide enough to make overnight electrolyser hydrogen production economic

Overview of the sensitivity analysis results

The sensitivity analysis suggests that there are a key set of parameters that have a significant impact on the future role of hydrogen technology, as they affect hydrogen use by more than 10%. Policies to reduce CO_2 emissions, the socio-economic environment and the rate of hydrogen technology developments are of key importance. However, in the presence of CO_2 incentives that drive major fuel substitution, energy-security policies and competing technology options seem of less importance. In general, the sensitivity analysis shows a significant downside potential and limited upside potential for the parameters varied (Table 6.2).

The following *variables* are of high importance, as they affect hydrogen use by more than 10%:

- The presence of CO_2 policy targets.
- The contribution of non-Kyoto countries to reducing their emissions substantially.
- Fuel tax regimes for hydrogen.
- Future oil prices.
- Post-2050 planning considerations.
- The availability of the FutureGen-type option for the cogeneration of hydrogen and electricity from coal.
- The successful development of CCS technologies.
- The acceptance of nuclear.
- The ultimate minimum cost of FCVs and the FCV drive system lifetime.
- The timing of FCV cost reductions.
- Consumer acceptance and awareness of more efficient technologies ("hurdle-rates").
- Hydrogen supply transition issues and the development of a centralised production system.

The following *variables* affect hydrogen use by less than 10%:

- Delaying the introduction of CO_2 policies by 15 years.
- Alternative fuel taxes increasing to 100% of gasoline taxes.
- Policies to improve the security of oil supply.
- Accelerated cost reductions for renewable technologies.
- Lower biomass availability.
- Allowing 25% reduced power capacity requirements for fuel cells in FCVs.
- Assuming low "hurdle-rates" for the residential and commercial sectors.

Assuming a lower capacity for FCVs has a limited impact on total hydrogen use, the more optimistic efficiency assumptions result in a 50% increase of FCV use. Therefore, capacity is also an important parameter. Energy-security policies can have a positive impact in a scenario without CO_2 policies, but their additional impact is limited when ambitious CO_2 policies are considered.

Table 6.2

Results of the sensitivity analysis

	Sensitivity parameter	Assumption	H_2 use 2050 (EJ)	Change (%)
	MAP scenario		**15.7**	–
Policy and socio-economic parameters	CO_2 incentives	BASE	3.6	–77
		USD 25/t of CO_2	13.4	–15
		USD 100/t of CO_2	28.3	+80
	CO_2 policy scope	USD 50/t, Kyoto countries only	9.1	–42
		USD 25/t, Kyoto countries only	3.7	–76
	CO_2 policy timing	CO_2 policy delayed 15 years	16.1	+3
	Supply security	Max. 33% transportation fuels from imported conventional oil	16.1	+3
	Market structure	MAP, but high "hurdle-rate" for transport sector	10.9	–31
	Market structure	MAP, but low "hurdle-rate" for residential/commercial sector	14.6	–7
	Fuel tax regime	Converging taxes for all transportation fuels	16.7	+6
		No fuel tax on hydrogen	21.7	+38
	Fuel prices	A high oil price of USD 40/bbl	20.5	+30
	Planning time horizon	2070	8.9	–43
Competing options	Nuclear electricity potential	No constraints on nuclear expansion	12.6	–19
	H_2 production cost from nuclear S-I	30% cheaper	21.4	+36
	Renewable electricity cost	More technology learning results in lower cost	14.9	–5
	Biomass potential	100 EJ primary biomass (halved)	17.2	+9
Hydrogen technologies	IGCC cogeneration	No FutureGen-type plant with CCS	10.6	–33
	CCS	No CCS	7.5	–52
	Technology learning	High FCV system cost of USD 105/kW	6.3	–80
	FC life span	One fuel cell replacement during vehicle life	13.1	–17
	Engine power	60 kW instead of 80 kW	16.7	+6
	Future FCV efficiency compared to advanced ICE	Factor 2.95 instead of 1.82	16.6	+7
	Technology development path	FCV cost reduction delayed by 15 years	11.6	–26
		FCV cost reduction 10 years earlier	16.5	+3
	Transition issues	Including transition issues	9.1	–42
	Hydrogen production scale	Only decentralised	7.2	–54
	Hydrogen distribution cost	Halved in the residential sector	17	+8

Chapter 7.

SCENARIO ANALYSIS AND REGIONAL ACTIVITIES

HIGHLIGHTS

- Hydrogen may conquer a significant market share if vigorous policies for climate change mitigation and energy security are combined with considerable reductions in the costs of hydrogen and fuel cells. Under these conditions, various emerging technologies contribute to stabilising emissions and help diversify the energy system. Hydrogen and fuel cells are part of this broad technology portfolio.

- In the most favourable scenario, with incentives to reduce CO_2 emissions and quickly declining hydrogen and fuel cell costs, hydrogen emerges as a player in the energy system beyond 2030. In this scenario 12.5 EJ of hydrogen would be used by 2050, mostly in the transportation sector. While in absolute terms this appears as a limited amount of energy in comparison with the total primary energy supply of around 785 EJ, its impact on transportation is very significant. The efficiency of PEM fuel cell vehicles is such that some 30% of the global fleet of passenger cars (some 700 million cars) would be fuelled by this relatively small amount of hydrogen. Fuel cell vehicles would start gaining market share between 2020 and 2025.

- If the hydrogen produced for energy use is added to the hydrogen used for other applications (refinery and chemicals), more than 22 EJ of hydrogen would be used by 2050. This represents more than a four-fold increase with respect to the current level of hydrogen production.

- However, hydrogen plays a significant role only under favourable assumptions. Under less optimistic assumptions for technology development and policy measures, hydrogen and fuel cells are unlikely to reach the critical mass that is needed for a successful market uptake. In this case, market introduction barriers would cause competing fuels and technology options, such as biofuels and synfuels from coal and gas, to play a more important role.

- If the most favourable scenario is compared to a similar scenario where hydrogen and fuel cells are not part of the technology portfolio, the net benefit of hydrogen and fuel cells is found to be a 5% reduction in CO_2 emissions (1.4 Gt CO_2) and a 2% reduction in oil use by 2050. This may appear to be a limited benefit. However, if vigorous CO_2 policies are in place, a number of alternative fuels and technologies, such as hydrogen, biofuels, CNG and FT synfuels from coal and gas with CCS, would all be playing a role in a competitive energy market. In such a diverse and optimised world, neither hydrogen nor any one of the other emerging technologies is crucial to mitigate emissions, but their collective uptake results in emission stabilisation.

- However, the lack of hydrogen would result in significant changes in the transportation system. The 30% of passenger cars and light-medium trucks fuelled by hydrogen fuel cells by 2050 would be replaced by ethanol vehicles (10%) and advanced gasoline ICEVs, gasoline hybrids, and natural gas fuelled vehicles (20% in total). The increased use of gasoline and natural gas to fuel vehicles would account for a total emissions increase of 1.4 Gt CO_2 per year.

- The diversification of the energy system is such that the lack of hydrogen in the energy mix does not imply dramatic changes in energy security. The net impact would only be a 2% increase in total conventional and unconventional oil use by 2050. However, oil imports from the Middle East would be 14% higher by 2050 due to the earlier depletion of non-Middle East oil supply sources. This would be associated with a rapid expansion of oil substitutes.

- Stationary fuel cell capacity in all scenarios ranges from 200 to 300 GW by 2050. This is equal to some 2-3% of total installed capacity. This result suggests that stationary fuel cells, namely SOFCs and MCFCs, represent a robust technology option that is not significantly affected by policy strategies and other variables. Most of these fuel cells would be fired by natural gas, but up to 22% of them could use oil refinery products. As a consequence, these fuel cells would not result in a reduction of emissions.

- Stationary fuel cells would concentrate in the residential, commercial and industrial sectors, and fill the market between large-scale CHP units and small-scale boilers, thus extending the economic feasibility of CHP to the scale of buildings. Fuel cells for centralised power production play a role in only one scenario, where in combination with coal-fired integrated-gasifier combined-cycles, some 25 GW of IGCC-SOFC plants are installed world wide by 2050.

- Hydrogen PEM fuel cells for stationary applications do not show up in any scenarios. This result can be explained by the cost of a dedicated hydrogen supply system and by the flexibility of the SOFC and MCFC systems, which do not need a fuel reformer, are less sensitive to poisoning than PEM fuel cells, and have superior conversion efficiency. Stationary hydrogen fuel cells, however, could benefit from the development of a hydrogen distribution system for transport. Such a synergy has not been considered in the analysis. So, in principle, hydrogen fuel cells could play a more important role than the results in these scenarios suggest.

- In cost-optimal scenarios, hydrogen production in the early market uptake phase is primarily from decentralised natural gas reforming and electrolysis, while centralised production from coal and natural gas, with CO_2 capture and storage, plays a major role in the longer term. Production from nuclear and renewable energy does not play a significant role. However, the cost of hydrogen production from nuclear heat and from biomass might be only slightly higher than from fossil fuels. If so, nuclear and renewable hydrogen could enter the production mix, especially if cost is not the only criterion for the selection of the production technology or if CO_2 capture and storage technologies are not available or competitive.

- If ambitious climate and energy-security policies are adopted, the regional potential for hydrogen and fuel cells seems to be high in the OECD regions and in China. In all regions, transport applications dominate the hydrogen market. The share of hydrogen FCVs varies widely across regions. In the most optimistic scenario, China is the region with the highest hydrogen FCV share (60%) in 2050, but this result is highly dependent on the scenario assumptions. The same applies to India, which has an FCV share of 42%. In OECD countries, the share seems to be somewhat more stable across scenarios. In the most favourable scenario the FCV share is 10% in Australia, 22% in Japan, 35% in Canada, 36-48% in Europe and 42% in the United States. Hydrogen use would start around 2020 in Europe and North America, and around 2025 in the other regions. Differences in hydrogen penetration across regions may be explained by different economic conditions, discount rates, availability of infrastructure, citizen attitude to investment in capital-intensive technologies, energy and fuel taxes, and mobility needs. The lower per capita use in the OECD Pacific can be explained by the lower energy intensity in key countries such as Japan and the lower annual car-mileage, which does not favour investment in capital-intensive technologies such as FCVs.

The sensitivity analysis in Chapter 6 showed that a number of parameters can significantly affect the potential for hydrogen and fuel cells. When combined, these individual drivers may interact in ways that reinforce or offset their respective individual impacts. Scenario analysis is a way of assessing such interactions. A scenario is defined as a coherent combination of parameters and assumptions that can influence the future role of hydrogen and fuel cells.

This chapter discusses and compares four scenarios that have been developed on the basis of the sensitivity analysis illustrated in the previous chapter. The scenario analysis is not intended to provide predictions for the future of hydrogen and fuel cell technologies, but instead depicts in a quantitative manner the role these technologies could play under a set of selected assumptions for energy policies and technology development. Also, the four scenarios discussed here do not pretend to cover the full spectrum of possible developments. The outcomes of the scenario analysis can be used to gain more insights regarding uncertainties and to develop hedging strategies to deal with these uncertainties. The results also provide information on the consequences of energy policy strategies and measures on hydrogen and fuel cell prospects. Finally, they can highlight key R&D areas and directions to further develop hydrogen and fuel cell technologies in order to maximise their chances of success. The four scenarios are first discussed on a global level and subsequently analysed from the perspective of their regional implications.

Global scenario analysis

The four scenarios (A, B, C and D) in this analysis are characterised by the acronym ESTEC that summarises the five dimensions used to define the scenarios: environment (E), supply security (S), technological progress (T), economic conditions (E) and competing options (C). Each dimension in each scenario is associated with a plus (+), minus (–) or neutral (0) symbol in series following the acronym, or beneath each letter, indicating that a set of parameters for that dimension have a positive, negative or neutral effect on the potential use of hydrogen and fuel cells. For instance, a higher incentive to reduce CO_2 emissions would be characterised by a plus sign under the E for environment or as the first sign in a list following ESTEC. The parameters that are considered in these scenarios are those that were identified to be of high importance in the sensitivity analysis described in Chapter 6.

Environmental policies (E) are represented through CO_2 reduction incentives that can vary in level, coverage and timing. Either all countries or only countries that have ratified the Kyoto Protocol are assumed to apply the incentives. The CO_2 reduction incentive is a way of representing the combined impact of policies, regulations, subsidies, taxes, etc., that have the effect of reducing emissions and enhancing energy security. Given the nature of many CO_2 reduction options, this incentive also tends to encourage options that result in significant benefits in terms of energy-security (*e.g.* policies to foster more efficient vehicles). However, in other circumstances (*e.g.* the use of coal) environment and energy-security goals are in potential conflict. From an economic point of view, the CO_2 incentives have the net effect of giving hydrogen technologies a benefit that is equivalent to the incentive level multiplied by the marginal CO_2 effect. The CO_2 reduction incentive is a modelling tool capable of easily representing a set of coherent policies. The evaluation of single, regional or sector-specific policy measures would be impractical and of limited relevance to a global analysis with a long-term perspective. Moreover, it would not be capable of assessing whether a certain option makes economic sense. By setting a level for the incentive, this approach then lets the model identify cost-effective solutions.

Explicit energy-security policies (S) are represented through targets to reduce oil import dependency and through taxation policies that favour the use of alternative fuels over conventional oil. The import dependency has been limited to one-third of total transportation fuel demand in three out of the four scenarios for OECD countries and China. The sensitivity analysis in Chapter 6 indicated that such policies can have an important impact in the case of weak CO_2 policies. Moreover, three scenarios assume that by 2050 fuel taxes on alternative fuels gradually converge on the current regional gasoline taxes. One scenario assumes that taxes on alternative fuels reach only 75% of the gasoline tax level by 2050.

Technology advances (T) in hydrogen and fuel cells are modelled through three sets of variables: the cost of the FCV drive system, the efficiency of the FCVs and a gradual transition from distributed to centralised hydrogen production. This last model characterisation is intended to represent the additional effort needed to overcome transition and infrastructure barriers, such as the chicken-or-egg problem. Transition issues may significantly reduce or delay hydrogen penetration in the energy market. All four scenarios in this chapter have the same assumptions for the transition issues. The important point is that these issues were not considered in the BASE and MAP scenarios. As for the cost of the FCV drive system, two different cost levels of USD 65/kW and USD 105/kW are assumed to be achieved over time. The relative efficiency of FCVs compared to advanced ICEVs was set at a constant value of 1.82 (the MAP and BASE level) or assumed to improve gradually to 2.95 by 2050.

Economic conditions (the second E) are modelled through oil and gas price assumptions, as well as the discount rates in the transport, service and residential sectors. Three scenarios assume a higher average oil price path of USD 35/bbl by 2030, which then increases to USD 40/bbl in 2050. As in the WEO 2004 Reference Scenario, one scenario uses a lower oil price assumption of USD 29/bbl in 2030, which is constant thereafter. In each scenario, the gas price follows the oil trend. Varying discount rates reflect consumer willingness to invest in capital goods, their time preferences, and the impact of government information campaigns and policies.

Finally, the prospects for competing options (C) includes a set of assumptions for alternative technologies, transportation fuels, CO_2-free electricity production from nuclear and renewable energy, and fossil fuels with CCS. Technology progress for renewables has been modelled through learning assumptions that are in line with either the MAP scenario or with more optimistic technology learning assumptions (see the MAPREN scenario in Chapter 6). The biomass potential is assumed to be100 EJ or 200 EJ per annum by 2050. The potential of nuclear is the same as in the MAP scenario, that is, twice as high.

The detailed assumptions for each of the ESTEC scenarios are presented in Table 7.1. The story behind each of the ESTEC scenarios is presented below.

A. ESTEC – – + + –

Weak CO_2 policies, liberalised markets and market-driven technological development

Weak CO_2 policies (no post-Kyoto quantitative targets), moderate government support for emerging technologies and a lack of government stewardship in decreasing oil dependency characterise this scenario. All types of alternative fuels are developed further by economic conditions, public and private R&D investment, and competition among energy companies. From a policy viewpoint, governments focus on the continued liberalisation of the global markets in order to strengthen competition and growth. In comparison with other scenarios, this scenario represents *a technology and market-driven future*. In this scenario, hydrogen and fuel cell technologies will only be chosen if they can compete with other energy options on a cost basis. This is a very challenging environment in which to achieve a transition to hydrogen.

B. ESTEC 0+++–

Strong new CO_2 policies in Kyoto countries and rapid technological development

Ambitious CO_2 policies in countries that ratify the Kyoto Protocol are balanced by limited abatement policies in other countries. Continued uncertainty about the prospects for conventional oil supply results in policy efforts to reduce oil imports. Substantial new R&D policy efforts foster technology development and breakthroughs. This scenario depicts a continued lack of agreement on CO_2 policies at an international level, which is somewhat compensated for by significant technology progress. Whether or not considerably different CO_2 incentives in Kyoto and non-Kyoto countries are compatible with the macroeconomic equilibrium among regional economies is open to discussion, but it is beyond the scope of this analysis.

C. ESTEC 0+–––

Strong new CO_2 policies in Kyoto countries, but technological development lags

With CO_2 and energy-security policies the same as in the previous scenario, this third scenario is characterised by technology development lags and/or a reluctance by consumers to accept new technologies. Government tax policies in favour of alternative fuels partially compensate for the technology lag. As a consequence, most emphasis is put on biofuels and synfuels that can be integrated into the existing fuel supply infrastructure. The development of these alternative fuels reduces the relative attractiveness of hydrogen. Given the importance of rapid technological progress for hydrogen as identified in the sensitivity analysis, this is perhaps the most challenging environment for hydrogen and fuel cells.

D. ESTEC +++++

Strong new CO_2 policies world wide, with rapid technological development

Driven by the evidence of climate change and the spirit of co-operation, all countries agree in the coming two decades to combat CO_2 emissions and global warming. Continued oil price fluctuations and increased concerns about energy-security issues result in new policies to limit oil dependency in industrialised countries. Technology development proceeds rapidly for hydrogen due to industrial and government-sponsored RD&D activities. The policy emphasis on hydrogen focuses less attention on synfuels and biofuels, while industry is reluctant to invest in alternative options that lack government support. As a consequence, the technology progress for alternative options lags behind hydrogen. This is the most favourable scenario for hydrogen.

Comparing scenarios A and B highlights the importance of government policies, because these two scenarios differ in environmental (first E) and security (S) policies only. Comparing scenarios B and C highlights the importance of the technology progress and economic conditions ("hurdle-rates" and the oil price). Scenario D reflects an optimistic case where policy, socio-economic trends and technology developments work together in a way that is favourable for hydrogen and fuel cells.

Table 7.1

Characteristics of the ESTEC scenarios

SCENARIO	A ESTEC – – + + –	B ESTEC 0 + + + –	C ESTEC 0 + – – –	D ESTEC + + + + +
E **Environmental Policy**	• USD 25/t CO_2 in Kyoto area • Zero elsewhere	• USD 50/t CO_2 in Kyoto area • USD 10/t CO_2 elsewhere	• USD 50/t CO_2 in Kyoto area • USD 10/t CO_2 elsewhere	• USD 50/t CO_2 everywhere
S **Supply Security**	• No new policy initiatives • Gradually converging fuel taxes	• Max. 33% oil imports in OECD countries and China • Gradually converging fuel taxes	• Max. 33% oil imports in OECD countries and China • Synfuels tax is 75% of gasoline tax by 2050	• Max. 33% oil imports in OECD countries and China • Gradually converging fuel taxes
T **Technology Progress (for H_2 & FCs)**	• Rapid • 2025 FCV drive system cost of USD 65/kW • Infrastructure transition considered explicitly • High relative efficiency of FCVs	• Rapid • 2025 FCV drive system cost of USD 65/kW • Infrastructure transition considered explicitly • High relative efficiency of FCVs	• Moderate • 2025 FCV drive system cost of USD 105/kW • Infrastructure transition considered explicitly • Reference relative efficiency of FCVs	• Rapid • 2025 FCV drive system cost of USD 65/kW • Infrastructure transition considered explicitly • High relative efficiency of FCVs
E **Economic Conditions**	• Low hurdle rates in transport, service and residential sectors • Higher oil & gas prices, USD 35/bbl by 2030	• Low hurdle rates in transport, service and residential sectors • Higher oil & gas prices, USD 35/bbl by 2030	• High hurdle rates in transport, service and residential sectors • 2004 WEO RS oil & gas prices, USD 29/bbl by 2030	• Low hurdle rates in transport, service and residential sectors • Higher oil & gas prices, USD 35/bbl by 2030
C **Competing Options**	• 200 EJ pa primary biomass • High growth in other synfuels • High nuclear expansion • Cheap renewable electricity	• 200 EJ pa primary biomass • High growth in other synfuels • Limited nuclear expansion • Cheap renewable electricity	• 200 EJ pa primary biomass • High growth in other synfuels • Limited nuclear expansion • Cheap renewable electricity	• 100 EJ pa primary biomass • Limited growth in other synfuels • Limited nuclear expansion • Reference renewable electricity

Note: pa = per annum and RS = reference scenario. The maximum percentage of oil imports is relative to total transport fuel use.

Results of the scenario analysis

Global hydrogen demand

The most favourable set of assumptions in the ESTEC scenarios for hydrogen, Scenario D, result in hydrogen demand appearing from 2015 onward and reaching 12.4 EJ in 2050 (Figure 7.1). This is less than the 15.7 EJ in the MAP scenario, because the MAP scenario does not take into account transition issues, such as the difficulty of infrastructure deployment, the early dominance of more expensive decentralised production and the overall chicken-or-egg problem during the transition phase. While transition technologies such as decentralised hydrogen production are essential for the uptake of hydrogen, they tend to be more expensive than large-scale centralised production. They also reduce the rate at which hydrogen penetrates the market with respect to an ideal world where large-scale capacity and infrastructure are in place at the very beginning of the process. The overall result of the transition is a more gradual uptake of large-scale industrial processes. Moreover, the assumption of a 62% higher efficiency for FCVs than in the MAP scenario results in 38% lower hydrogen demand at a given market share.

However, total world hydrogen production would be higher than this 12.4 EJ, which is just for energy use, as the production for non-energy uses in 2050 is not included. Currently, chemical and refinery uses require around 5 EJ of hydrogen per year. Although not modelled, non-energy use could raise total hydrogen production by 2050 to more than 22 EJ per year, or more than four times current hydrogen production. Also, because of the higher efficiency of FCVs in this scenario, the contribution of 12.4 EJ of hydrogen to satisfying energy service demand is higher than in the MAP scenario. This is particularly true for Scenario D, because by 2050, 97% of all hydrogen used is in the transport sector.

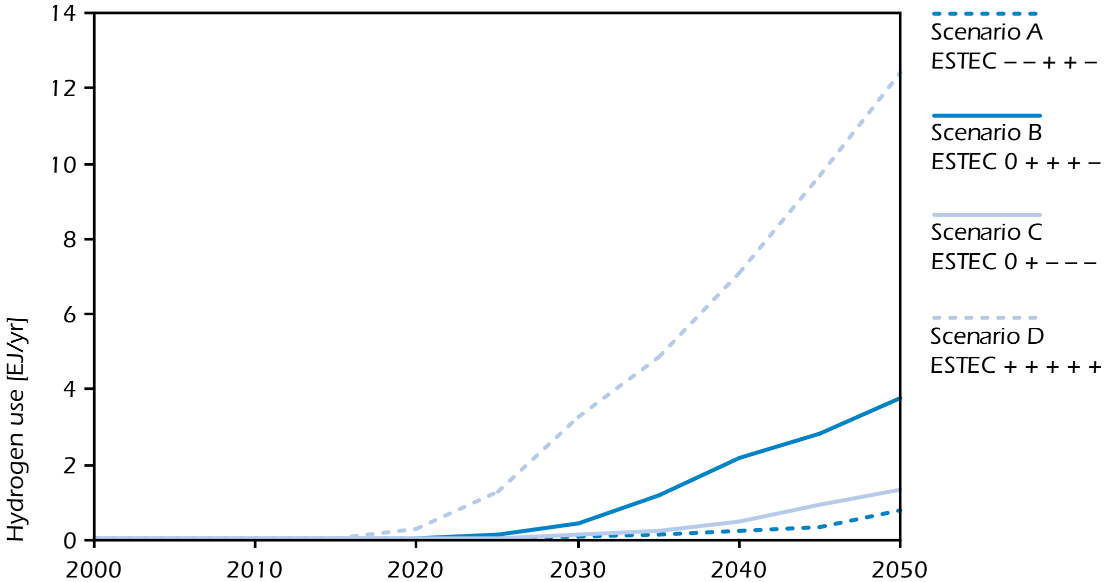
The other three scenarios (A, B and C) show significantly lower hydrogen demand than scenario D. This suggests that widespread hydrogen use in the next 50 years is not a "given fact" and that hydrogen seems to play an important role only if rather ambitious CO_2 policies are in place and further favourable conditions exist. The fact that scenario D shows significantly higher hydrogen use than the other three scenarios is the consequence of a number of factors. In addition to environmental policies, strong technology advances driven by government RD&D programmes in conjunction with the relatively slow development of competing options play a key role.

According to scenarios A, B and C, different sets of assumptions could considerably limit hydrogen prospects in favour of other options. However, apart from conventional options, no emerging technology option seems in the position to play a dominant role in the future transport fuel mix (Figure 7.2). Therefore, hydrogen should be regarded as one potentially important option in a broad portfolio of technologies that can gain market share if a rapid improvement in their performance and economics is achieved, and if aggressive CO_2 abatement policies are in place.

In terms of impact on the overall energy system, hydrogen plays a minor role. Figure 7.3 shows the primary energy mix in the four ESTEC scenarios. Differences across the four scenarios are limited, as all scenarios include substantial actions to reduce emissions, improve efficiency and reduce energy demand. The total primary energy demand use varies by just 10% across scenarios (from 785 EJ to 865 EJ in 2050), while total fossil fuel demand varies from 620 EJ to 700 EJ, thus suggesting a continued heavy reliance on fossil fuels. However, coal use does decrease continuously from scenario A to scenario D, which is also the most efficient scenario. In absolute terms, the impact of hydrogen on the overall energy mix is in the range of a few percentage points. Even assuming a low conversion efficiency of 60% of primary energy into hydrogen, the total hydrogen used in the most favourable scenario D would require less than 3% of total primary energy use.

Figure 7.1

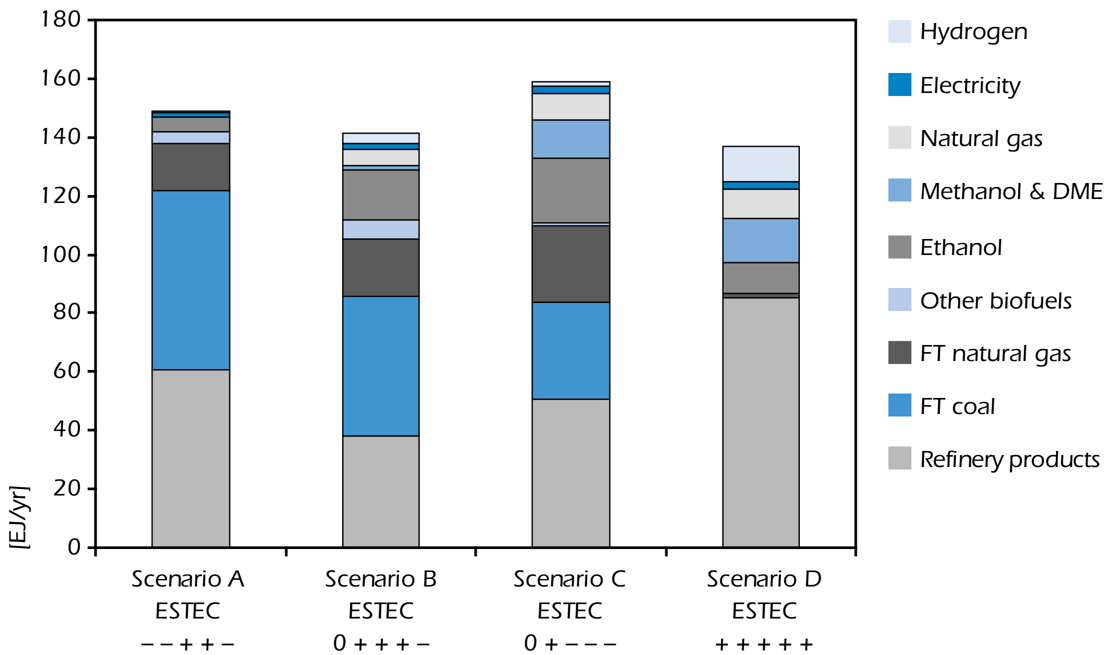
Global hydrogen demand in the ESTEC scenarios



Key point: Up to 12.4 EJ of hydrogen use in 2050, but a significant down-side potential

Figure 7.2

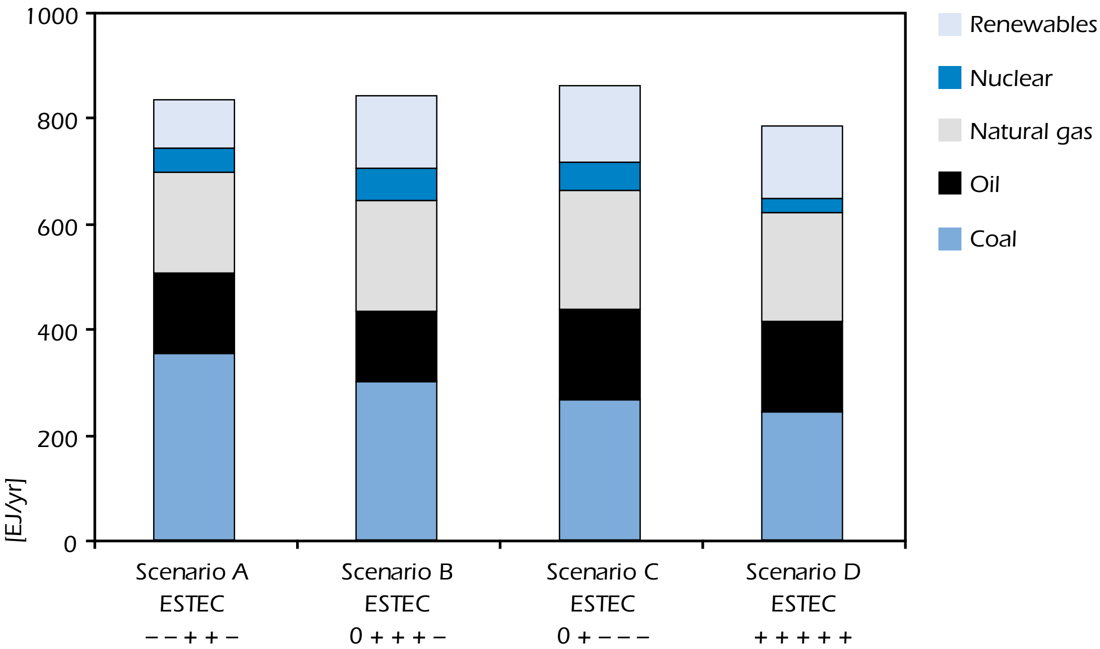
Transport sector fuel demand in the ESTEC scenarios, 2050



Key point: No dominant role for emerging technologies in the future transportation energy mix, but contribution by a broad technology portfolio

Figure 7.3

Total primary energy demand in the ESTEC scenarios, 2050



Key point: *The differences between the scenarios are limited*

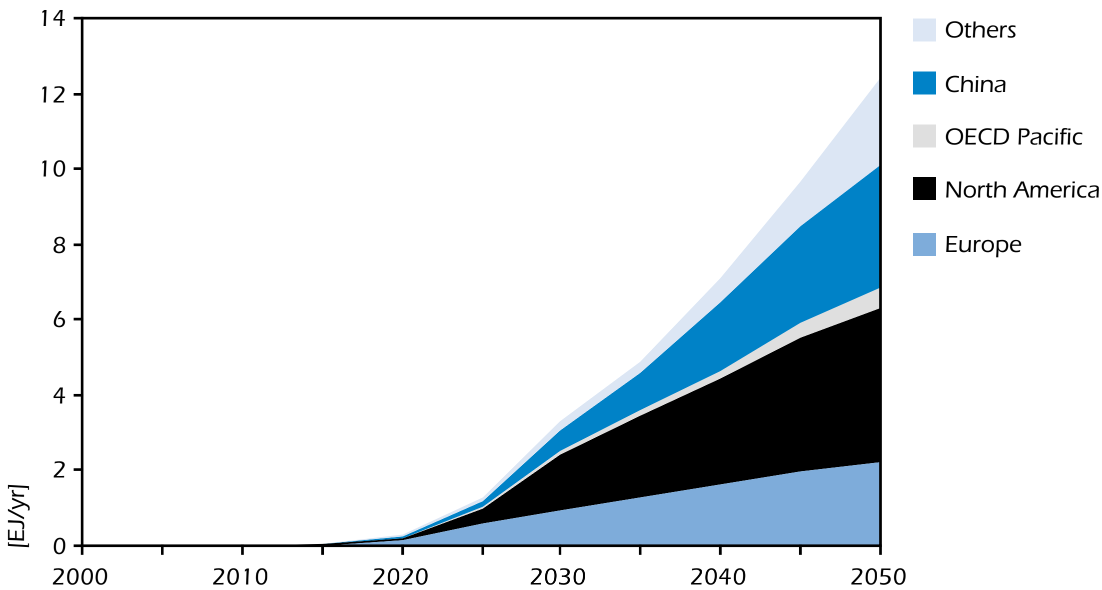
There are also some interesting differences in the regional distribution of hydrogen demand. In the most favourable scenario for hydrogen (scenario D), hydrogen demand is concentrated in North America, Europe and China (see Figure 7.4). Hydrogen demand starts around 2015 in Europe and North America, and around 2025 in the other regions. This uptake in various regions over a relatively short period of time suggests that favourable conditions for hydrogen introduction exist under different economic conditions.

In absolute terms, hydrogen demand in the OECD Pacific region is significantly lower than in the other OECD regions. However, the difference in per capita hydrogen use is much smaller (Figure 7.5). This difference can be explained by lower overall energy demand in this smaller region. Also, lower annual car-mileage in the key countries of the OECD Pacific does not favour investment in highly efficient, but high-cost technologies. In scenario D, hydrogen use in OECD regions ranges from 3.5 GJ to 7 GJ per capita, with considerably lower values in other regions. The higher per capita hydrogen use in North America can be explained by the higher annual mileage, larger car-size, lower fuel efficiency and higher car ownership rates in this region. The implicit assumption in the analysis is that the characteristics of the North American market are inherent to low population density, low-density suburban habitation patterns and a heavy reliance on SUVs and pick-up trucks. Current North American per capita oil product demand is a factor of 2.2 to 2.6 times higher than in Europe and the OECD Pacific regions, and can to a large extent be attributed to these factors. Therefore, a high per capita demand for hydrogen is not necessarily a measure of its success, but simply the result of adverse factors beyond the control of regional energy policy makers.

In three out of four scenarios, per capita use is lower in all regions outside the OECD. This suggests that hydrogen is a more robust energy technology option for the OECD region.

Figure 7.4

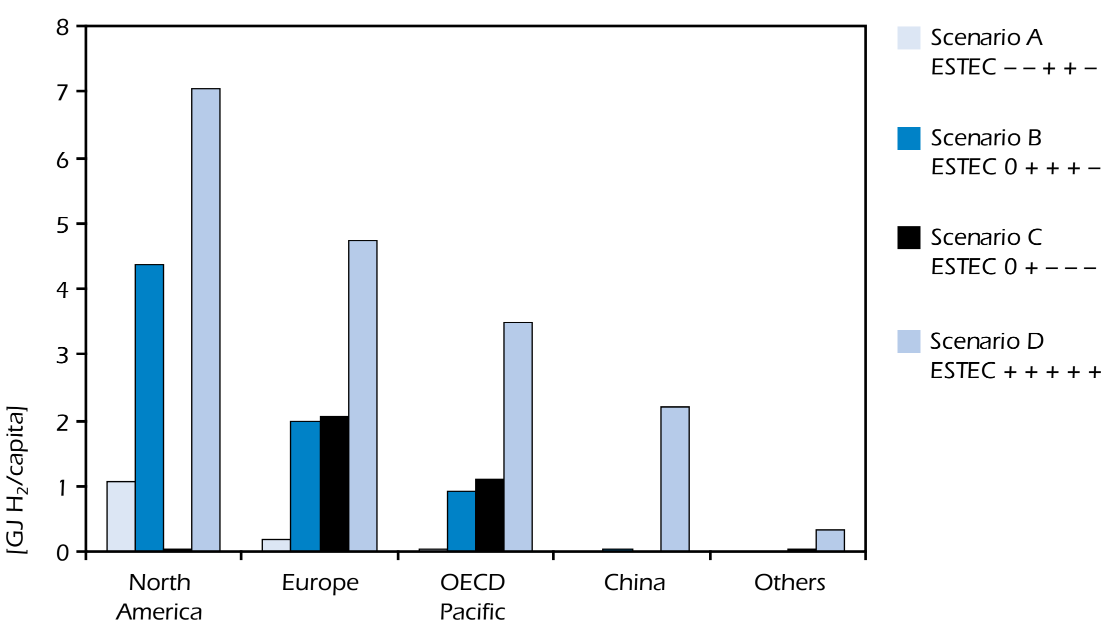
Hydrogen demand by region in Scenario D (ESTEC +++++)



Key point: North America and Europe are the key markets

Figure 7.5

Hydrogen demand per capita in the ESTEC scenarios, 2050



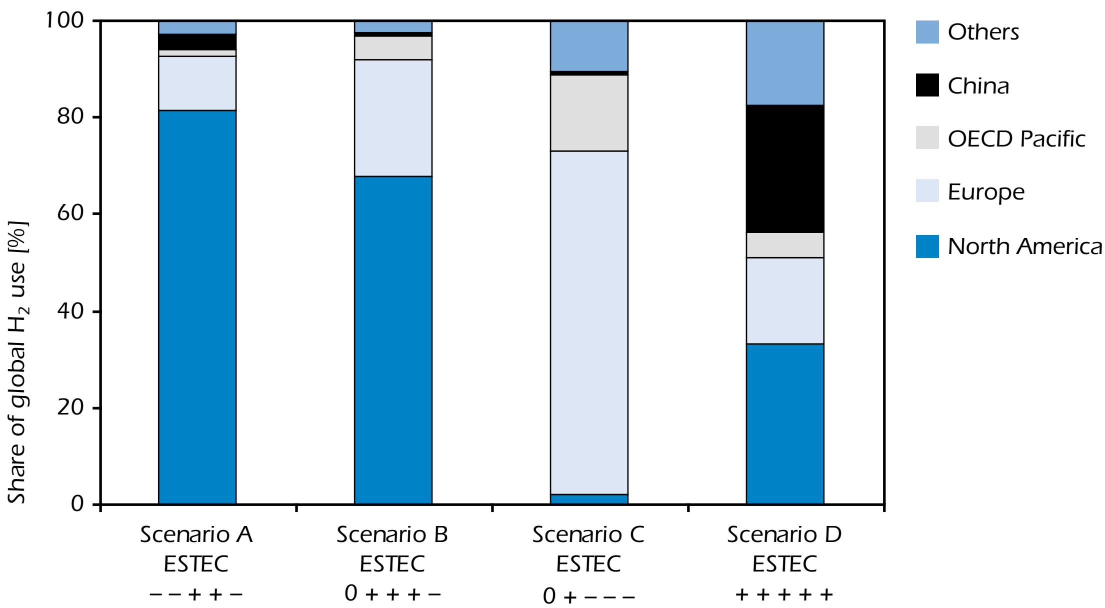
Key point: North America and Europe have the highest per capita demand

The regional distribution of hydrogen demand in all scenarios is shown in Figure 7.6. Total hydrogen use is concentrated in North America and Europe in three out of four scenarios. Only in scenario D does the share of these two regions drop to 50%. Consistent with current trends, this result suggests that industry efforts to introduce hydrogen will focus on these two markets. In scenario D, the importance of developing countries such as China and India suggests that international co-operation on hydrogen RD&D should be expanded to integrate such countries, which could be major hydrogen consumers in the future. The results also suggest that these countries may skip the transition to an intensively oil-based transport sector, found in current industrialised countries, and move to hydrogen instead. However, given the sensitivity of developing countries to prices, affordable hydrogen supply and end-use technologies will be an essential element of such a scenario.

In all the ESTEC scenarios, hydrogen use is lower than in the MAP scenario. In the most optimistic scenario, scenario D, hydrogen use in 2050 is 21% lower than in the MAP scenario. This can be explained by the effect of the hydrogen transition issues and by the higher vehicle efficiencies in scenario D. Obviously, if hydrogen use is too low, one can question whether hydrogen will really make it to the market given the investment and transition challenges.

Figure 7.6

The share of hydrogen demand by region in the ESTEC scenarios, 2050



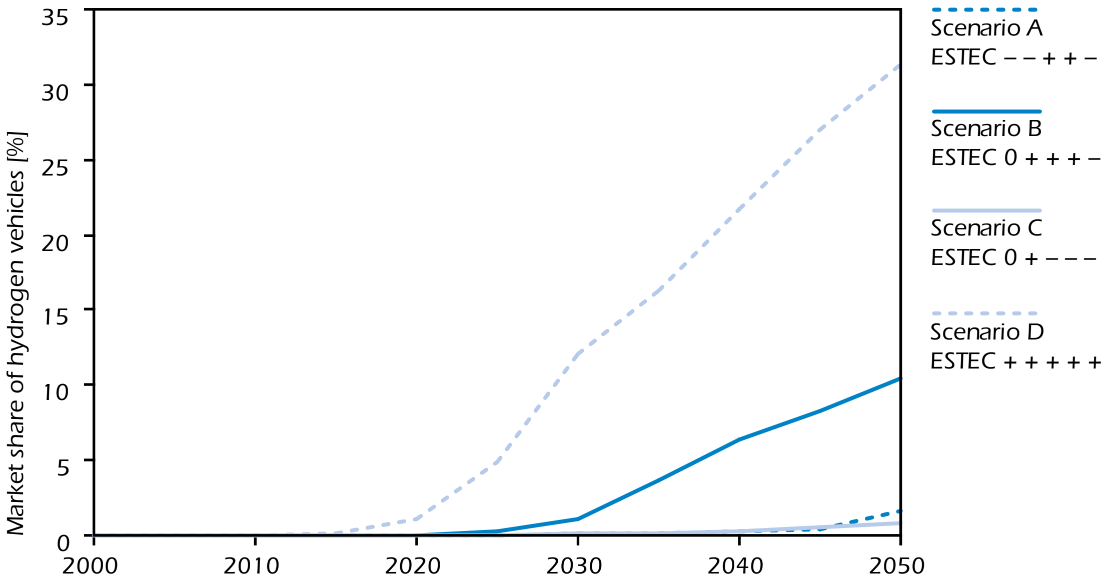
Key point: *North America and Europe are the key markets in all scenarios*

Hydrogen use in transport

Although hydrogen demand in scenario D appears modest at just 12.4 EJ of H_2 (2-3% of total primary energy in 2050), this hides the profound impact fuel cells have on the transportation sector. The introduction of hydrogen starts from 2015 in OECD countries and 2025 in other regions in scenario D. FCV share of the global stock of passenger cars and light/medium trucks in 2050 is around 30% (Figure 7.7). The share is significantly lower in the other three scenarios (A, B and C), ranging from 1% to 10% in 2050. Scenario D results indicate that a relatively small amount of hydrogen can supply a very significant part of the global vehicle fleet, because of the high efficiency of FCVs.

Figure 7.7

Share of hydrogen-fuelled vehicles in the passenger car and light/medium truck markets



Key point: *Up to 30% market share by 2050, but a significant down-side potential*

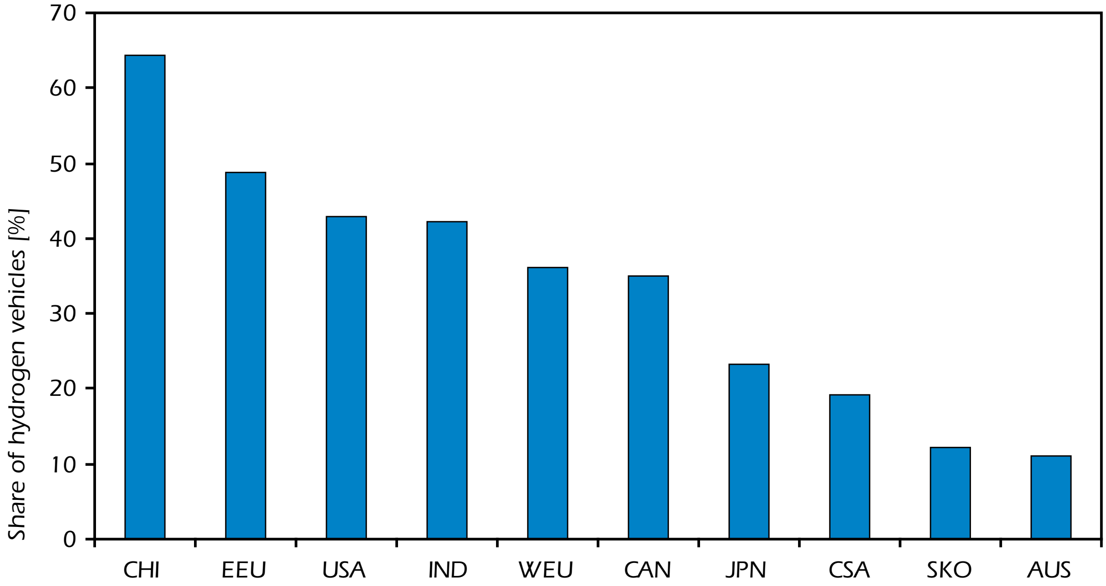
The share of hydrogen FCVs varies widely across regions. In scenario D, China has the highest share of hydrogen-fuelled vehicles in 2050 (Figure 7.8), but this result is highly dependent on the scenario assumptions. In other scenarios, hydrogen use in China is negligible. The same applies to India, were hydrogen-fuelled vehicles reach 42% of the vehicle stock in 2050 in scenario D. The share in OECD countries varies significantly: 10% in Australia, 22% in Japan, 35% in Canada, 36-48% in Europe and 42% in the United States. Hydrogen use in other regions is negligible. The differences in FCV share can be explained by a range of factors, such as the availability of other transportation fuel options, annual driving range, region-specific cost factors, and technology lock-in due to existing infrastructure. This result suggests that hydrogen is an option of special interest for most OECD countries and large, rapidly growing developing countries with limited indigenous oil resources. The projected share of hydrogen-fuelled vehicles is consistent with the stock shares that were used for the investment cost analysis in Chapter 3.

The important share of hydrogen FCVs in China and India in scenario D is remarkable. It can be explained by a combination of factors. There is a technology "leap-frogging" effect as the transport system in these countries starts expanding rapidly at the same time as there are sufficient indigenous coal reserves in both countries that could be used for hydrogen production. These two factors are scenario-independent. Then there are scenario-dependent factors: the lack of other synfuels in combination with new ambitious energy policy goals, and access to hydrogen and fuel cell technology. This combination of factors is a precondition for this outcome.

Some 75% of hydrogen is used for passenger cars and 25% for delivery vans. However, both vehicles are developed at the same time, so no clear incentive appears for delivery vans as a "niche" market. Moreover, there is little hydrogen use in buses (1% of total hydrogen use). This result can be explained by the competition in this market segment and the limited expected energy efficiency gains for hydrogen fuel cell buses (20% better than diesel buses, compared to a factor of almost three for cars). Instead, the model selects diesel-hybrid buses. However, increased efficiency and stronger emphasis on local urban air pollution could change the optimal choice in favour of hydrogen fuel cell buses. In addition, if the relationship between cost reduction and actual investment is taken into account, there would be a stronger incentive to develop these niche markets first.

Figure 7.8

Stock share of hydrogen-fuelled LDVs and delivery trucks in key regions in Scenario D (ESTEC +++++), 2050



Key point: *High shares are projected for China, India and many OECD countries*

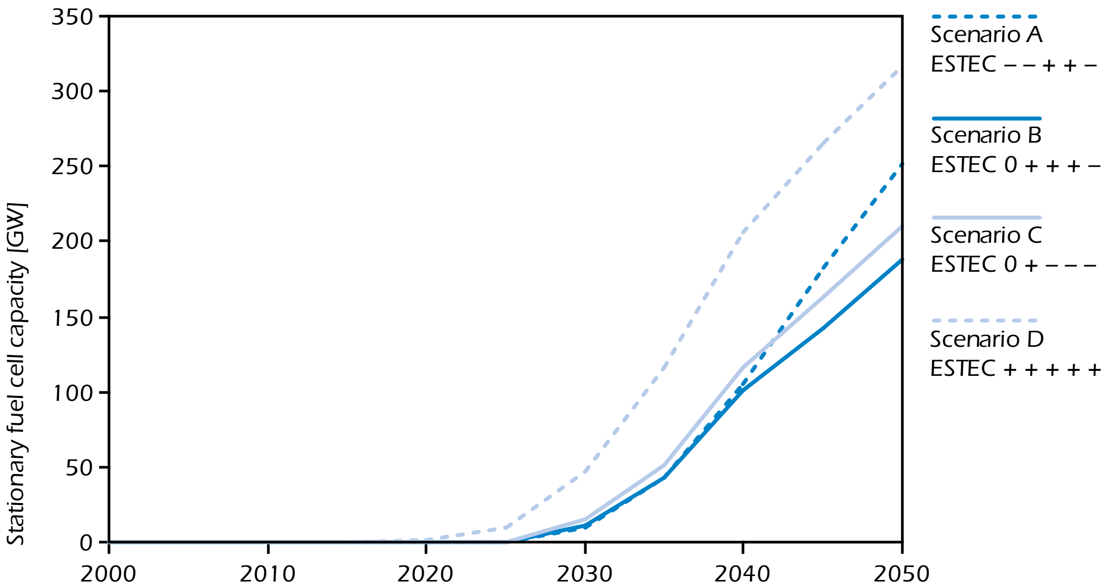
Hydrogen and fuel cell use in stationary applications

Scenario D (ESTEC +++++) is also the most optimistic ESTEC scenario for fuel cells in stationary applications (Figure 7.9). This scenario sees a rapid introduction of fuel cells from 2020 onward, with the total stock of fuel cells reaching around 300 GW by 2050. This is around 3% of the total electricity production capacity at that time. In the other three scenarios, the introduction of fuel cells starts five years later and reaches 200-250 GW by 2050. In all scenarios, the electricity production share is almost equal to the share in production capacity. This means that the average load factor of fuel cells is similar to the average load factor for all power plants.

Most of these fuel cells (SOFCs or MCFCs) are fuelled by natural gas and oil products, rather than by hydrogen. The use of stationary fuel cells is also less scenario-dependent than the use of FCVs and hydrogen in general. The economic advantages of stationary fuel cells, compared to hydrogen FCVs, are due to their higher load factor and the higher cost of competing options. The fact that the share of stationary fuel cells is reasonably stable across various scenarios indicates that they represent a robust technology option that should be included in any balanced energy technology portfolio.

Figure 7.9

Global stationary fuel cell use in the ESTEC scenarios



Key point: *Market introduction from 2020 and growing to 200-300 GW by 2050*

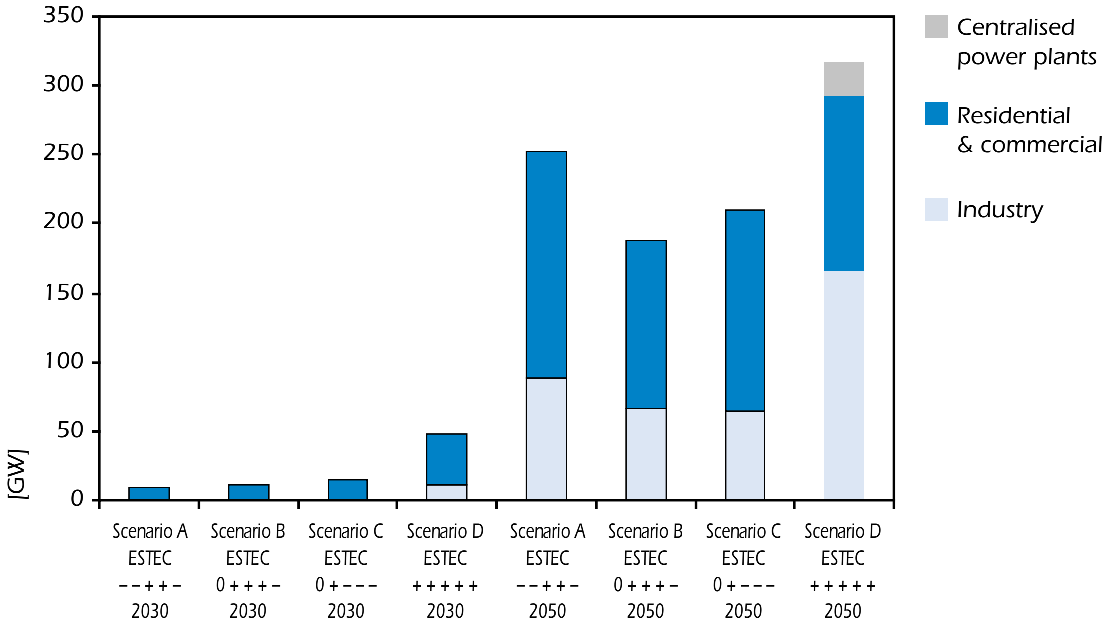
Stationary fuel cell use in 2030 is concentrated in the residential and commercial sectors (Figure 7.10). In the period 2030-2050, the main growth is in the cogeneration of electricity and heat (CHP applications) in the industrial sector. Fuel cells only play a significant role in centralised power production in scenario D, with about 25 GW of coal-fired IGCC-SOFC systems in 2050. The ESTEC scenarios highlight the important contribution of fuel cells in decentralised power production applications.

In terms of the fuel input used by these fuel cells, natural gas fuel cell systems dominate in both 2030 and 2050 (Figure 7.11). However, in 2050 an important proportion, up to 22% of all fuel cells, use fuel oil or other oil refinery products. In the most optimistic scenario, coal-gas fuel cells are used in centralised power plants. Interestingly, there is no use of hydrogen fuel cells for stationary applications in any of the ESTEC scenarios. This result can be explained by the high cost of a dedicated hydrogen supply system, but also by the flexibility of the SOFC and MCFC systems, which do not need a fuel reformer, are less sensitive to poisoning than PEM fuel cells, and have higher conversion efficiencies. Stationary fuel cells compete with a number of relatively low-cost CO_2-free electricity supply options such as renewables, centralised fossil-fuel power plants with CCS, and nuclear. Despite this, their share is rather stable across scenarios and is not very sensitive to any of the policy settings assumed. This can be seen either as an advantage or as a drawback for these technologies. For example, ever more ambitious CO_2 policies do not necessarily benefit stationary fuel cells.

Assuming the extensive use of hydrogen in transportation and the associated development of refuelling station infrastructure by 2050, a certain number of stationary hydrogen fuel cells could also be connected to the distribution system, thus improving the economies of scale of the overall hydrogen system. Such a synergy has not been considered in this analysis, but in principle the availability of hydrogen for automotive applications could be a driver for the use of hydrogen stationary fuel cells.

Figure 7.10

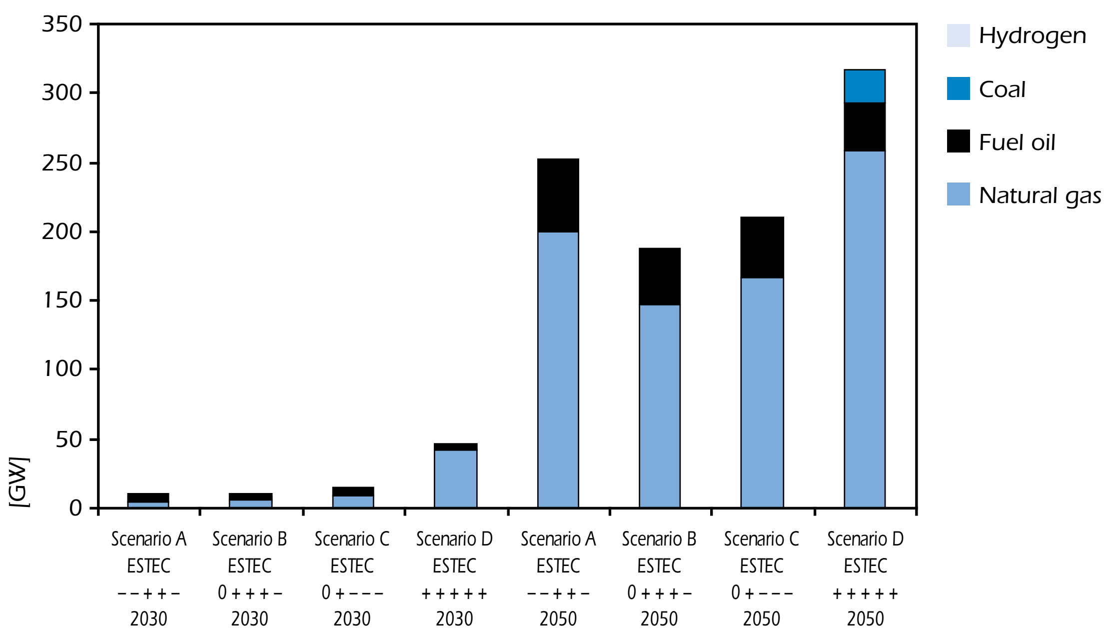
Global stationary fuel cell capacity by sector in the ESTEC scenarios



Key point: *Starting from 2020 and growing to 200-300 GW by 2050*

Figure 7.11

Global stationary fuel cell capacity by fuel input in the ESTEC scenarios



Key point: *Gas-fired systems dominate*

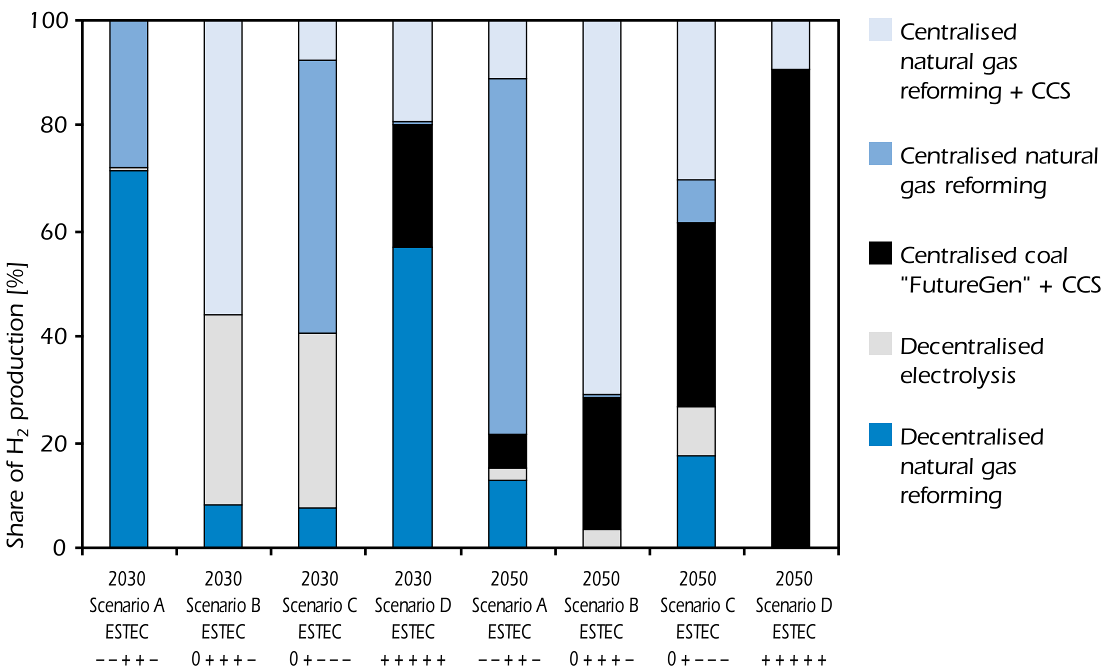
Hydrogen production by technology

Hydrogen production by technology in the early stages of the projection period is influenced by transition issues, with production in 2030 dominated by decentralised technologies using natural gas (Figure 7.12). Electrolysis appears in scenarios B and C, based on the overnight production strategy that uses off-peak electricity. In Scenario B, this production is concentrated in Europe and the United States. In scenario C, it is concentrated in Europe alone. The choice of electrolysis in these two scenarios, instead of decentralised natural gas reforming, may be explained by the combination of CO_2 incentives (that discourage decentralised natural gas reforming) and the need for a rapid transition to hydrogen based on CO_2-free electricity at an acceptable cost (which discourages electrolysis in scenario D). However, in absolute terms the quantities are rather small.

Centralised production technologies dominate the production of hydrogen in 2050. The most important production is from coal and natural gas feedstocks in association with CCS. In all four ESTEC scenarios, the production of hydrogen from nuclear and renewable energy does not play an important role, even in 2050. This result is based on the cost optimisation. Under certain assumptions, hydrogen produced from nuclear and renewables (biomass gasification with CCS or electrolysis using off-peak renewable electricity) would only be marginally more expensive than production from fossil fuels with CCS, and hence might enter the market. As the cost of hydrogen production is only one part of the hydrogen cost structure – transportation, distribution and use also play a key role – the additional cost of nuclear or renewable production may not be a significant obstacle to its uptake if government policy promotes these technologies.

Figure 7.12

Hydrogen production by technology in the ESTEC scenarios



Key point: *Initially decentralised electrolysis and natural gas reforming, followed by centralised production from gas and coal with CCS*

The model chooses technologies using purely economic criteria, analysing the marginal economic benefit of a technology by comparing revenues and expenses. It calculates a benefit/cost ratio (B/C ratio) where marginal revenues are divided by marginal costs. Technologies with a B/C ratio of 1 or higher will show up in the model results, while technologies with a B/C lower than 1 will not. However, given the uncertainties in technology development, it is useful to look at technologies with a B/C ratio close to one, as these processes do not appear in the model results, but are close to being competitive. The potential of hydrogen production processes has been further analysed on the basis of this B/C ratio. A B/C ratio of 0.9 or higher indicates a potentially attractive supply option, while a ratio of less than 0.9 indicates a supply option which is not close to being competitive. Table 7.2 provides an overview of the B/C ratios for hydrogen production technologies in 2050.[19] The B/C range given for each technology indicates the minimum and maximum values in the 15 ETP model regions. The B/C ratios in 2050 reflect a situation where centralised hydrogen production is a viable option for most regions. An analysis for earlier decades would result in more favourable B/C ratios for decentralised technologies given the assumptions used to account for the transition issues for hydrogen.

The B/C ratio analysis identifies two cost-effective technologies for which the B/C ratio is 1: coal gasification in FutureGen-type IGCC plants and centralised natural gas reforming. In both cases, the production is combined with CO_2 capture and storage, resulting in a virtually CO_2-free hydrogen production process.

Table 7.2

Benefit-cost ratios of hydrogen production processes across regions in Scenario D (ESTEC +++++), 2050

Process	B/C ratio (2050)
Nuclear S-I cycle	0.71-0.89
Solar thermal S-I cycle	0.56-0.76
Coal	
FutureGen cogeneration (centralised)	0.97-1.00
Gasification (centralised)	0.48-0.75
Gasification with CCS (centralised)	0.62-0.86
Biomass	
Gasification (centralised)	0.39-0.74
Gasification with CCS (centralised)	0.51-0.73
Photo-Biological (centralised)	0.31-0.56
Electrolysis	
Advanced electrolyser/inorg. membrane 1-30 bar (centralised)	0.42-0.93
Advanced electrolyser/inorg. membrane 1-30 bar (decentralised)	0.51-0.98
High temperature 1-30 bar (decentralised)	0.42-0.74
High pressure 800 bar (decentralised)	0.37-0.68
Advanced electrolyser/inorg. membrane 1-30 bar diurnal (decentralised)	0.50-0.92
Natural gas	
Steam reforming (centralised)	0.65-0.90
Steam reforming (decentralised)	0.66-0.92
Steam reforming with CCS (centralised)	0.71-1.00

19. *More details on the B/C ratio analysis, including B/C ratios for more technologies, are contained in Annex 3.*

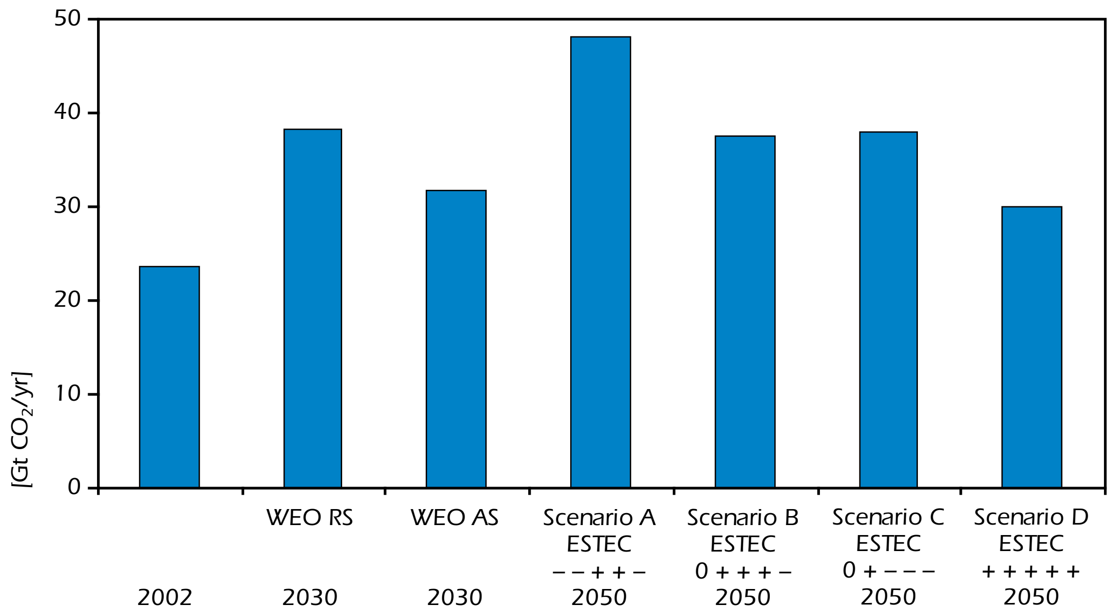
Other technologies that are relatively close to market introduction in certain regions are nuclear S-I cycles, centralised and decentralised electrolysis, and the decentralised steam reforming of natural gas. However, the B/C ratios vary widely across regions, and while certain technologies are close to being cost-effective in certain regions, they are further away in other regions. This suggests that a different hydrogen supply structure may evolve in different parts of the world. The B/C ratios also suggest that even in 2050, renewables supply options are still quite far from being competitive. However, at that time renewables represent a significant share of the electricity mix, ranging from 40% to 50% of total electricity production in 2050. Therefore, the combination of renewable electricity production and electrolysis could become a viable option, especially in scenarios A, B and C where electrolysis is used in 2050. While the average electricity mix contains substantial amounts of renewables, the marginal electricity supply is not necessarily based on renewables. But such an option would not be far from competitiveness in certain world regions.

Hydrogen's impact on CO_2 emissions

Figure 7.13 presents the CO_2 emissions in the four ESTEC scenarios in 2050, as well as the WEO 2004 Reference and Alternative scenario emissions in 2030. In scenario A, emissions continue to increase in the period 2030-2050. In scenarios B and C, stabilisation occurs at a level below 40 Gt of CO_2 per annum. Stabilisation occurs below 30 Gt of CO_2 per annum in Scenario D, with a significant reduction with respect to the WEO 2004 Reference Scenario emissions level in 2030. Scenario D is consistent with a stabilisation of CO_2 emissions in the atmosphere below 550 ppm. This is a consequence of effective CO_2 policies and the introduction of new energy technologies. Scenario D – the most favourable for hydrogen and fuel cells – shows that ambitious climate policies can make a difference, from both a technology and an environmental point of view.

Figure 7.13

Global CO_2 emissions in the ESTEC scenarios, 2030 and 2050



Source: IEA and IEA 2004a.

Key point: *The scenario with the lowest emissions is the scenario with the highest hydrogen and fuel cell use*

To quantify in more detail the benefits of hydrogen and fuel cells in reducing CO_2 emissions, scenario D was modified to exclude both hydrogen and fuel cells. The comparison with the original scenario D allows for a better understanding of the direct impact of hydrogen and fuel cells on emissions.

Without hydrogen and fuel cells, the emissions in scenario D increase by only 0.3 Gt of CO_2 in 2030 and by 1.4 Gt of CO_2 in 2050 over the original scenario D, or a 5% increase in 2050. If the hydrogen demand (12.4 EJ) were replaced by gasoline (2.93 GJ of gasoline to replace 1 GJ of H_2), the additional CO_2 emissions would amount to almost 3 Gt of CO_2. Gasoline indeed produces approximately 80 kg CO_2 per GJ[20], while hydrogen is virtually CO_2-free in scenario D. However, in the modified scenario D hydrogen is not just replaced by gasoline, but by energy efficiency measures (*e.g.* hybrids) and other alternative fuels. The hydrogen is replaced by an increased use of other fuel options, including ethanol, other biofuels, synfuels such as DME, fuels from FT synthesis, gasoline and natural gas. The substitution effect, where the emissions reduction incentive remains, is such that CO_2 increases by only 1.4 Gt in 2050. This effect illustrates the importance of a systems perspective to assess the impact of a technology. It also shows that scenario D yields a CO_2-optimised energy system. It builds on a number of emerging technologies, none of which is dominant. As a consequence, the presence or the absence of a single technology does not have a major impact. This improves the energy security of the system, but also reduces the margin for further optimisation and explains why hydrogen technologies apparently have a limited impact on the overall energy system.

This conclusion is also evident when analysing the emissions from the transportation sector (Figure 7.14). In this figure, the emissions are split into tailpipe emissions from vehicles, and upstream emissions from the hydrogen production processes. As might be expected, the main outcome of the incentives to reduce emissions is the significant reduction of the CO_2 emissions. This is driven by new, more efficient energy technologies and CO_2 capture and storage. In 2030, the difference between transport sector emissions in the BASE scenario and scenario D is limited, because the uptake of new technologies requires time to gain market share. However, in 2050 the difference is more important, as new technologies have gained a significant share of new sales and their share of the stock has risen to significant levels. The CO_2 policies and incentives open the door to competition among a number of clean and efficient emerging technologies that gradually gain market share. As mentioned above, none of these technologies seems able to dominate the market (there is no "silver bullet"), but the collective result is a significant abatement of emissions and an increase in the overall efficiency of the energy system (IEA, 2004b). The diversification is such that the lack of a single technology or fuel (*e.g.* hydrogen) does not imply dramatic changes in overall CO_2 emissions. The lack of hydrogen does, however, result in changes in the structure of the transportation system. In scenario D, about 30% of all passenger cars and light/medium trucks are fuelled by hydrogen in 2050. Without hydrogen and fuel cells, the share of ethanol vehicles increases by about 10 percentage points, while the remaining 20 percentage point gap is mainly filled by gasoline (advanced ICE and hybrids) and natural gas-fuelled vehicles. Along with the emissions coming from additional upstream synfuel processes, the increased use of gasoline and natural gas for vehicles account for the total increase in emissions of 1.4 Gt of CO_2 in 2050.

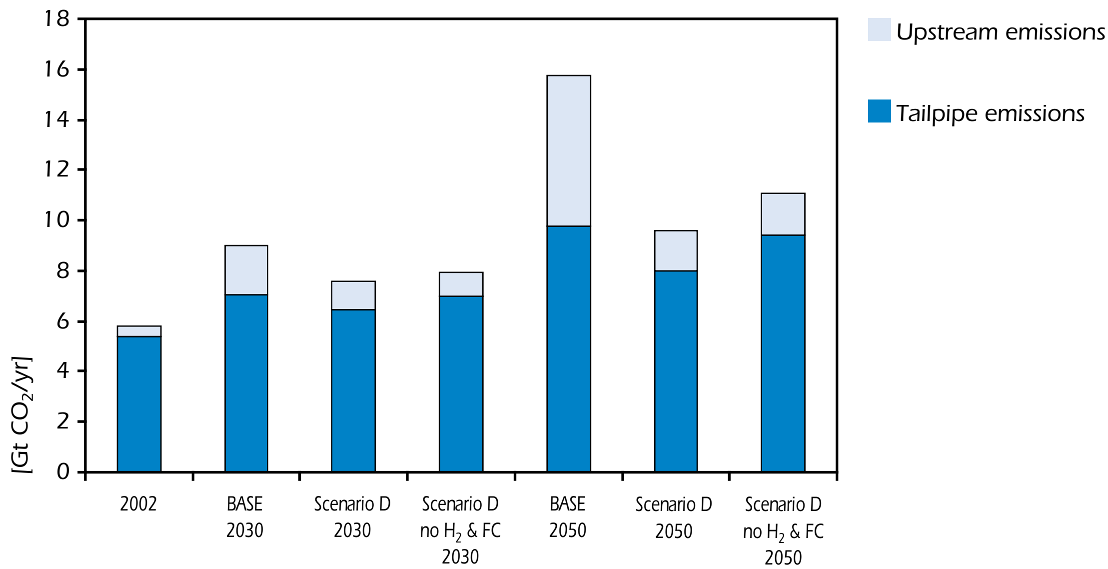
Another way to assess the benefits of hydrogen and fuel cells is to impose the same emission levels as a constraint at a regional level when excluding hydrogen and fuel cell use. In this case, other, more costly options must be applied to meet the same emissions targets. The cost difference is a measure of the benefits of hydrogen and fuel cells. In regions with high hydrogen and fuel cell use in scenario D, the difference in the marginal cost of CO_2 (the shadow price) required is in the range of USD 5-10/t of CO_2 in 2050 (*i.e.* a 5-10% increase). This effect is relatively modest

20. These are well-to-wheel emissions.

and in terms of average emission reduction costs, the effect is even smaller. For comparison, model runs with and without CCS or nuclear power show a marginal cost difference of USD 30-40/t of CO_2 (IEA, 2004a).

Figure 7.14

Transport sector emissions in scenario D with and without hydrogen and fuel cells, 2002, 2030 and 2050



Source: IEA, IEA 2004a and WBCSD 2004.

Key point: *Upstream emissions may grow quickly and must be considered in an emissions reduction strategy*

The impact of hydrogen on energy-security

The trade in oil and oil products, indigenous production of conventional and non-conventional oil, and indigenous synfuels production in the four ESTEC scenarios and the WEO 2004 Reference Scenario are presented in Figure 7.15. The WEO 2004 Reference Scenario is as an example of a scenario with no new policies. The WEO projects that the inter-regional trade in oil and refinery products will increase to 135 EJ in 2030, that total conventional and unconventional oil production (tertiary oil production and oil sands) will increase to 235 EJ, and that the production of synfuels (FT-fuels from gas, coal and oil, liquid biofuels, methanol/DME and natural gas for road transport) increases to 6 EJ.

Obviously, the scenarios A to D perform better than the WEO Reference Scenario in terms of energy diversification and energy security as measured by trade, because they include substantial new CO_2 policies. In these scenarios, new policies result in reduced oil imports, less oil production and more energy diversification, in particular in the long term (Figure 7.15). However, these benefits cannot be attributed to hydrogen and fuel cells alone. In fact, the "best" scenario for hydrogen prospects, scenario D (ESTEC +++++), seems to be the worst in terms of energy security. In 2050, this scenario shows the highest oil dependency, the highest trade in oil and lower diversification. This is in part because this scenario assumes a low potential for emerging non-hydrogen options. Other scenarios in the ESTEC family perform much better in terms of energy-security goals (scenarios

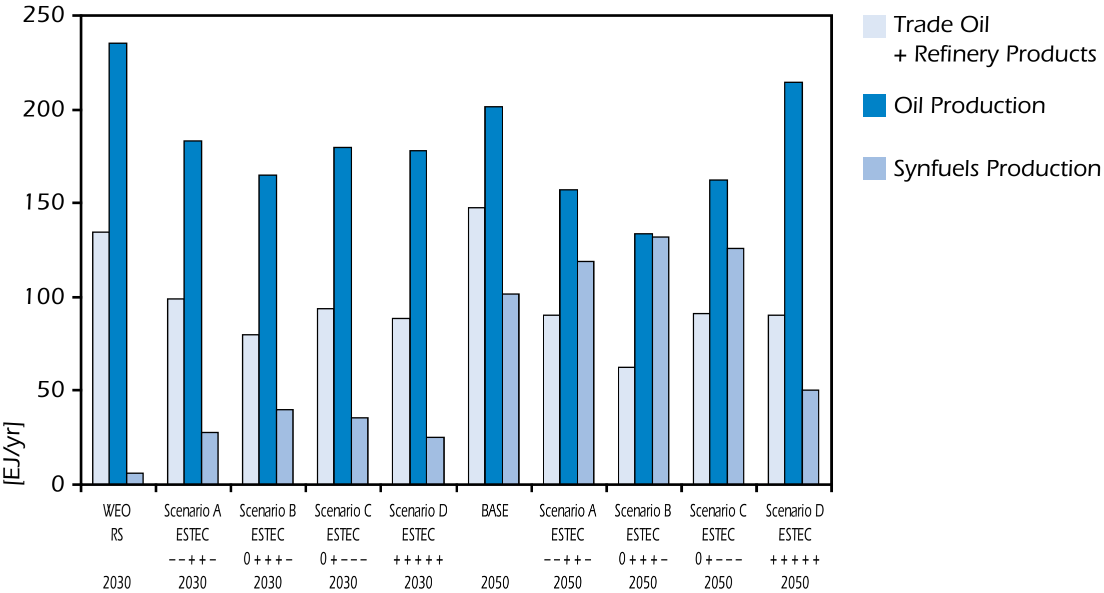
A, B and C). In line with other studies (Turton and Barreto, 2005, forthcoming), this result confirms that energy-security goals can be met in many ways and that hydrogen is just one option in a broad portfolio.

In the modified scenario D which excludes hydrogen and fuel cells, total oil demand (conventional and unconventional) increases by 2% in 2050 relative to the original scenario D. However, the share of oil imports from the Middle East in the global oil supply increases by 14%, or 12 EJ in 2050. The impact on oil imports is much more significant for two reasons. First, Middle East oil production represents just over half of total oil production in 2050. Therefore a 2% rise in total production translates into a 4% rise in Middle East production. Second, the rise in Middle East production is limited to the last decade. Prior to the last decade, other production options are more widely used. The rapid exhaustion of reserves outside the the Middle East exacerbates the dependency on Middle East oil in the last decade. Note that this result is only valid if other alternative fuels are severely constrained; if this is not the case, the energy-security benefits of hydrogen and fuel cells decrease. In general, while hydrogen can certainly make a contribution, it is not essential to improving energy security.

The benefits for energy security can also be expressed by hydrogen's effect on fossil fuel prices. The comparison of scenario D with and without hydrogen provides some insights into the importance of this impact. The oil price reduction is only around 3% in 2050 and the gas price reduction is negligible, except in the United States, where the reduction is around 6%. The effects are therefore relatively modest.

Figure 7.15

Oil trade and the oil production mix in the Base, ESTEC and WEO RS scenarios, 2030 and 2050



Note: NC = non-conventional oil (tertiary oil production, oil/tar sands and shale oil). Synfuels include FT-fuels from gas, coal and oil, as well as liquid biofuels, methanol/DME and natural gas for transportation sector use. RS = Reference Scenario.

Key point: Oil trade decreases significantly in all scenarios. Synfuels represent 20% to 50% of the oil market in 2050

Regional differences

This section discusses some of the important regional results for the ESTEC scenarios in the three OECD areas of North America, Europe and Pacific, as well as in China.

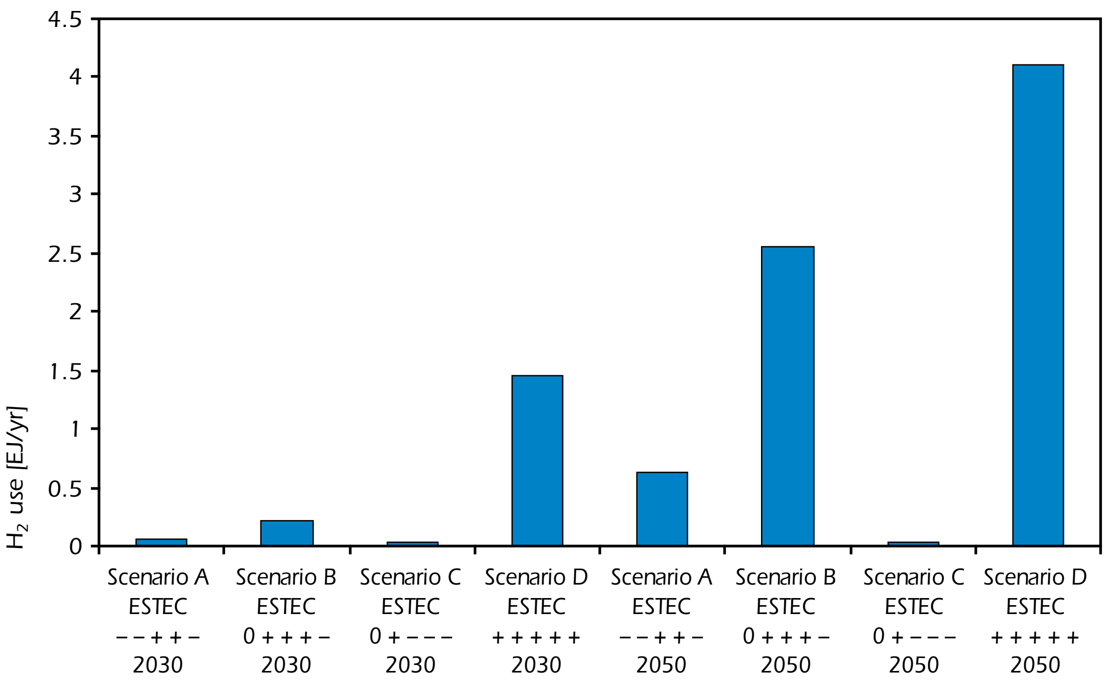
OECD North America

Hydrogen demand in OECD North America is significant in scenarios B and D, but limited in scenarios A and C (Figure 7.16). In contrast, the use of stationary fuel cells is significant in scenarios A and C by 2050, with an installed capacity that ranges from 26-42 GW (Figure 7.17). While scenario D has the highest hydrogen demand and no stationary fuel cell use, scenario A exhibits significant use of stationary fuel cells, but very modest hydrogen demand. This can be explained by the negative impact of CO_2 policies on stationary fuel cells fuelled by oil and gas. While hydrogen is a CO_2-free energy carrier that benefits from CO_2 policies, non-hydrogen stationary fuel cells do not necessarily benefit from CO_2 policies, as CO_2 capture in small decentralised plants is not available.

The range of the results in the ESTEC scenarios seems to lend support to ongoing activities in North America. The United States has a very ambitious hydrogen programme for the transportation sector, with commercialisation targets starting in 2015. There are also considerable efforts aimed at the development of stationary fuel cells, especially SOFCs. However, the results suggest that technology development alone might not be sufficient to achieve a substantial transition to hydrogen. While R&D spending is considerable, the cost of a transition to hydrogen would be much more substantial. Clear, long-term energy policies could help a transition process that could take decades.

Figure 7.16

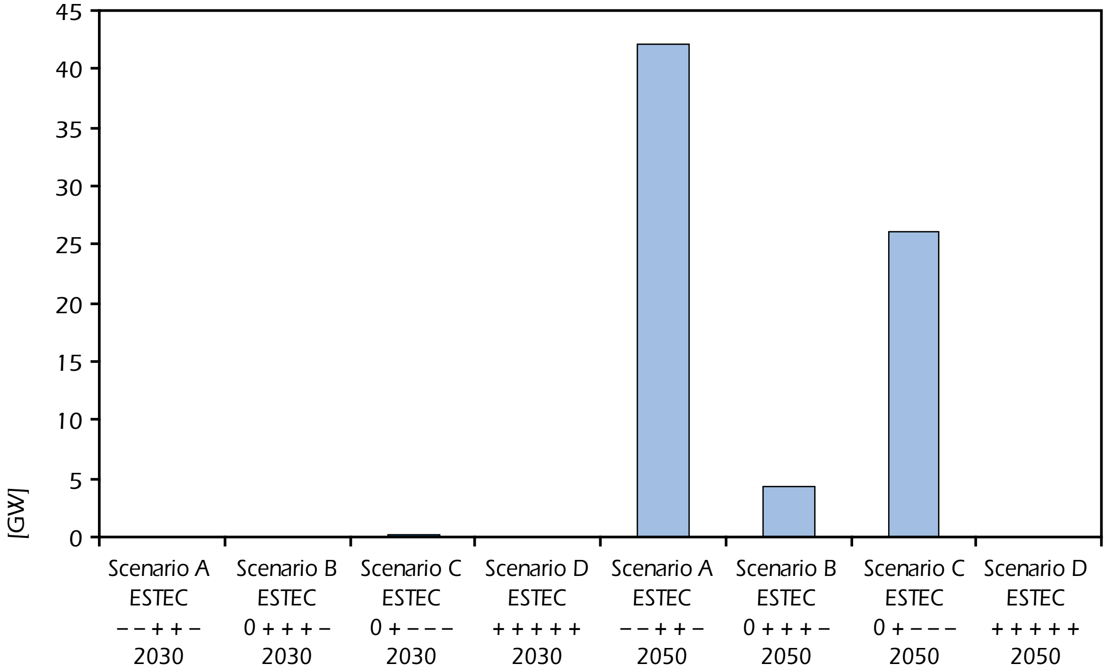
Hydrogen demand in OECD North America in the ESTEC scenarios



Key point: Up to 4 EJ depending on the scenario

Figure 7.17

Stationary fuel cell capacity in OECD North America in the ESTEC scenarios



Key point: Up to 40 GW depending on the scenario

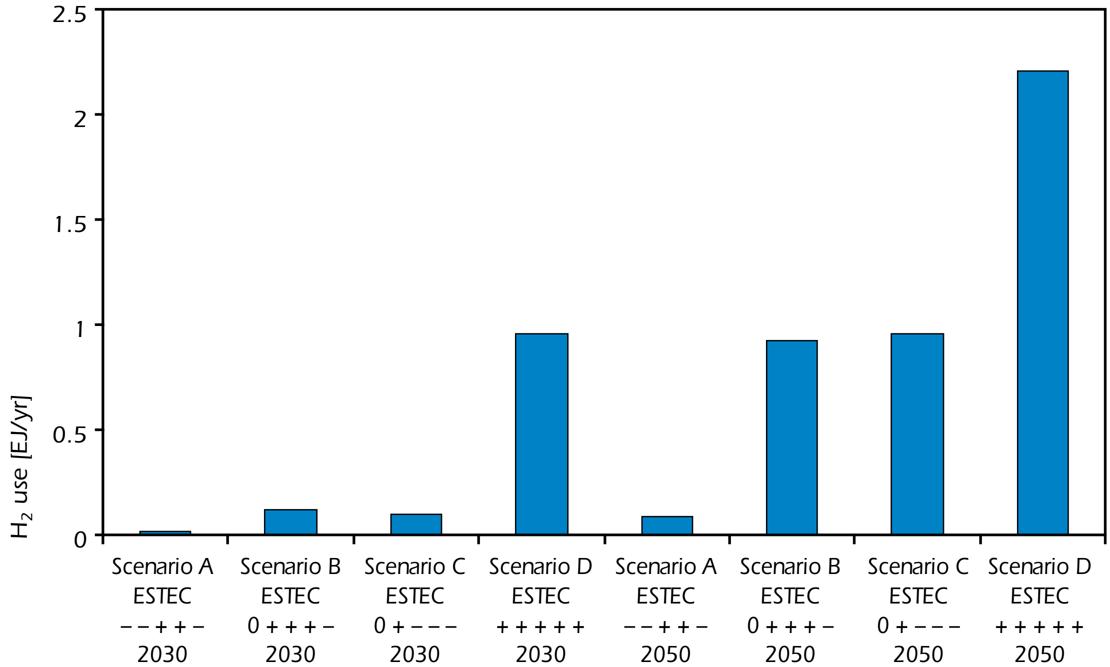
OECD Europe

Hydrogen demand in OECD Europe is negligible in 2030, except in scenario D, while demand increases to around 1-2 EJ in scenarios B, C and D in 2050 (Figure 7.18). Only in scenario A, where CO_2 policies and energy-security policies are weak, is the role of hydrogen negligible. Again, a significant number of hydrogen-fuelled vehicles generate what appears to be a modest level of hydrogen demand due to their high efficiency. The installed capacity of stationary fuel cells is significant in all four scenarios in 2050, ranging from 55 GW to 120 GW depending on the scenario (Figure 7.19). This result suggests that stationary fuel cells are more important in Europe than in North America, while their appearance in all four scenarios makes them a robust option in Europe.

The important projected role of hydrogen and fuel cells in Europe in these scenarios is in line with the significant European research effort in this area. However, the results suggest that Europe can not achieve a transition to hydrogen on its own. For example, international agreements will be needed for substantial CO_2 emissions reduction policies that provide the competitive advantage for these technologies to make an important contribution. A price of USD 25/t of CO_2 will not be sufficient to achieve a transition to hydrogen (scenario A). Similar to the case for North America, the transition to hydrogen should be considered as a long-term issue. While a lot of European discussions focus on hydrogen from renewals, this supply option seems of limited relevance in the coming decades. However, hydrogen can help reduce oil dependence substantially, although perhaps at the expense of higher imports of natural gas and coal.

Figure 7.18

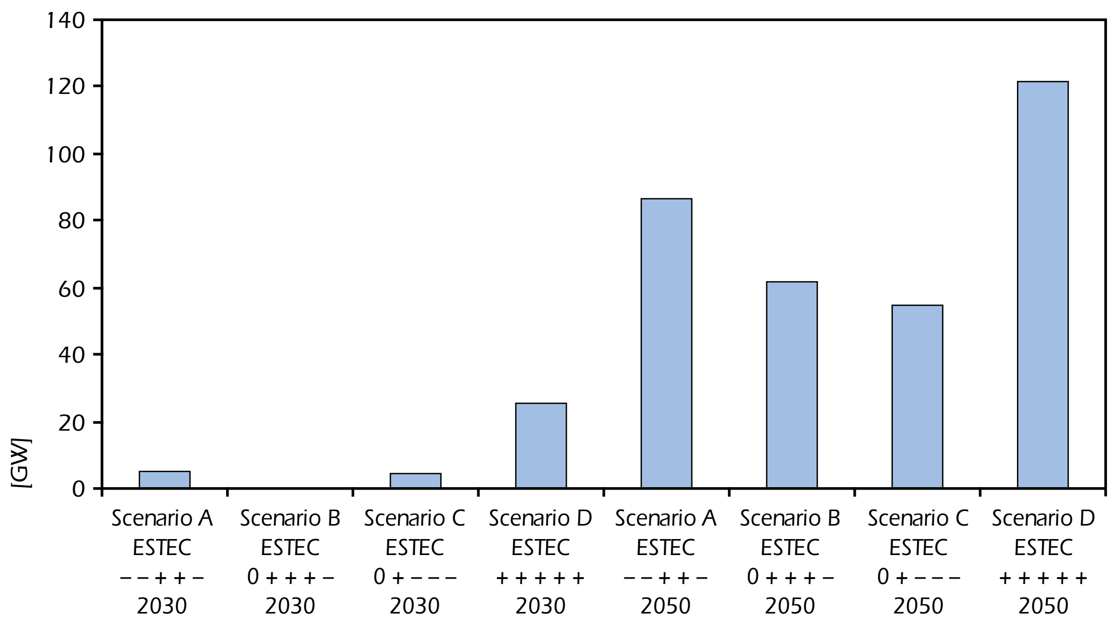
Hydrogen demand in OECD Europe in the ESTEC scenarios



Key point: Up to 2.2 EJ depending on the scenario

Figure 7.19

Stationary fuel cell capacity in OECD Europe in the ESTEC scenarios



Key point: Up to 120 GW, with strong growth in all scenarios

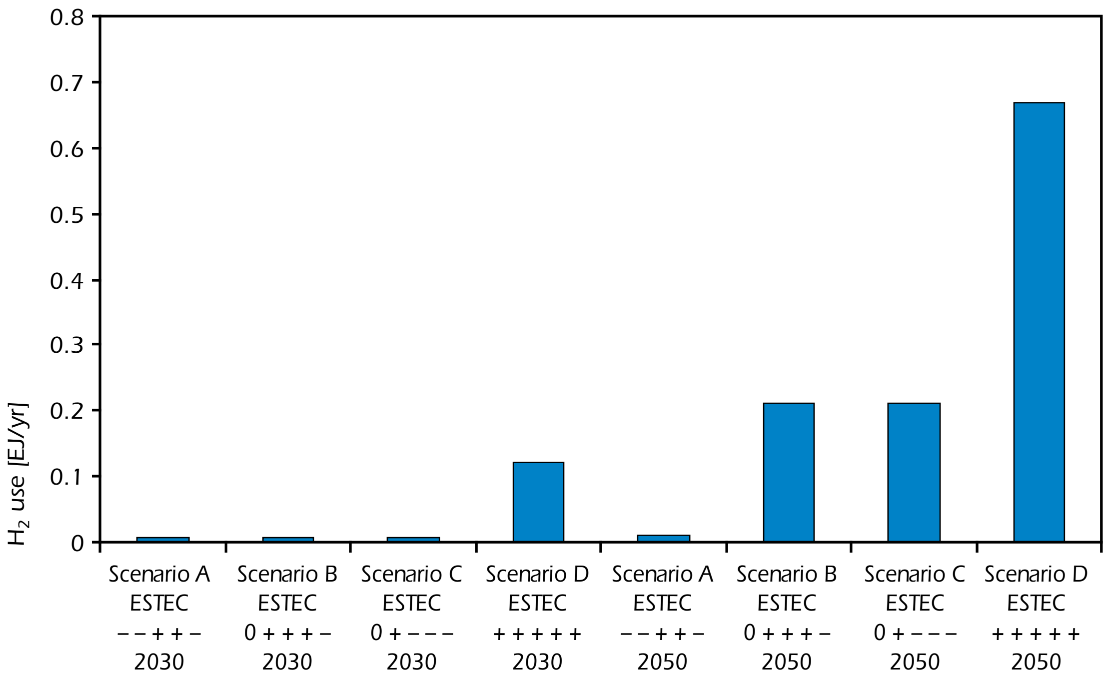
OECD Pacific

Hydrogen demand and stationary fuel cell use varies across scenarios in the OECD Pacific[21] (Figures 7.20 and 7.21). Hydrogen demand in scenario D amounts to 0.7 EJ in 2050. The scenarios for this region also show the importance of environmental and energy-security policies in the future of hydrogen, as scenario A shows virtually no hydrogen use. For stationary fuel cells, the results suggest an important role in scenario D, but limited potential in the other three scenarios.

The Pacific region is the OECD region where hydrogen appears to make the weakest contribution to environmental and energy-security goals. Given the important hydrogen programmes in Japan and Korea, this result deserves more attention. Low annual mileage in the most populous OECD Pacific countries is a significant handicap for highly efficient, but costly technologies such as FCVs. This is further exacerbated by the relatively high vehicle efficiency and ongoing success of hybrid vehicles in these countries, limiting the marginal efficiency gains of hydrogen FCVs. Finally, ambitious plans for nuclear power expansion when combined with the low annual mileage could make electric vehicles and plug-in hybrids serious competitors to FCVs. This is probably the region where the competition of drive systems and fuels is still most open. However, given the global character of the car manufacturers, one can question whether very different trends will emerge in different regions without economies of scale.

Figure 7.20

Hydrogen demand in OECD Pacific in the ESTEC scenarios

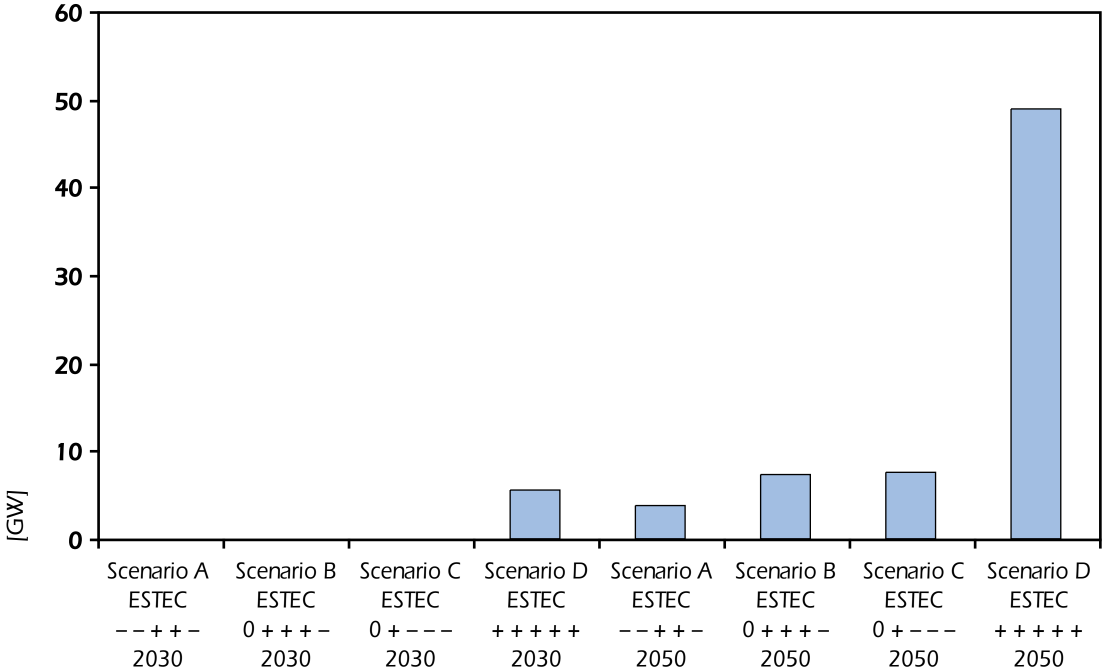


Key point: Up to 0.7 EJ depending on the scenario

21. *Australia, Japan, Korea and New Zealand.*

Figure 7.21

Stationary fuel cell capacity in OECD Pacific in the ESTEC scenarios



Key point: Up to 50 GW, depending on the scenario

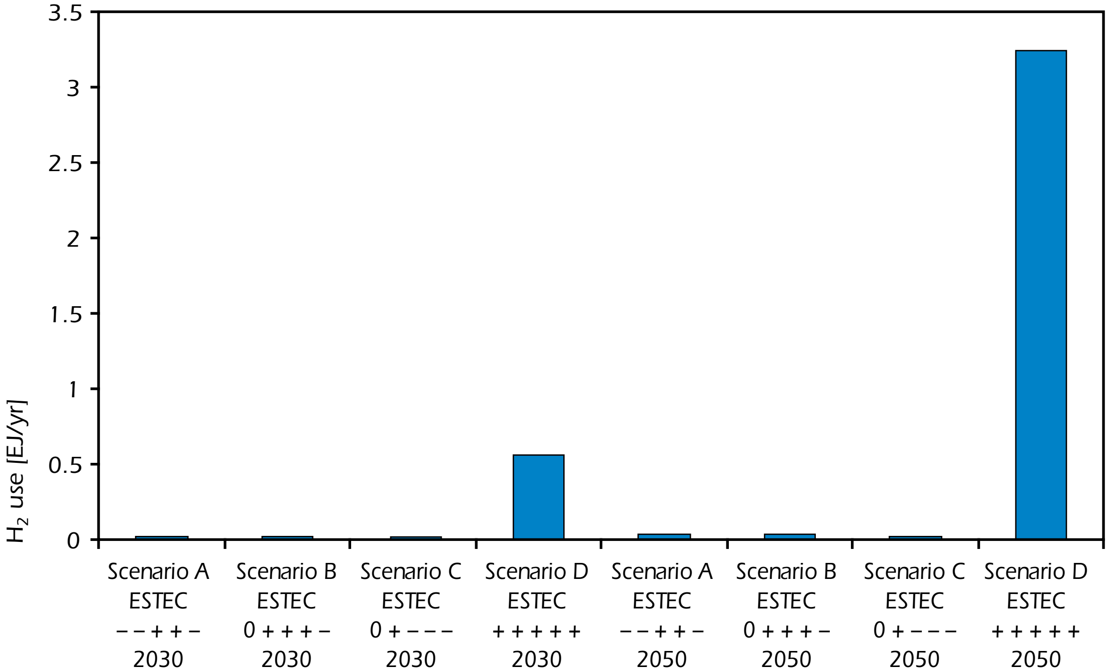
China

Of the four ESTEC scenarios, hydrogen demand in China is only significant in scenario D (Figure 7.22). It is the scenario where China adopts ambitious CO_2 policies and again suggests that a hydrogen transition will only happen in the case of ambitious policy targets. Energy-security policies alone are not sufficient to bring hydrogen to the market, even in a region with limited indigenous oil resources such as China.

Stationary fuel cells have not been considered for heating in the residential and service sectors in China. The reason is the wide range of climate zones in China that will result in very different evaluation perspectives for fuel cells. While fuel cells may make sense in northern China, their use in southern China seems less likely. In addition, the regional availability of natural gas poses constraints on stationary fuel cell use. The use of fuel cells in industry and in the power sector has been considered, but they are not chosen by the model in any of the four ESTEC scenarios. However, industrial fuel cell use may make sense in urban areas where the use of coal-fired boilers has been banned. In urban centres such as Beijing and Shanghai, where natural gas is available or will become available, there may be a role for fuel cells in industrial CHP applications in small to medium-scale industries. Given the importance of China to future demand trends, this is an area that would benefit from further analysis at a more detailed modelling level.

Figure 7.22

Hydrogen use in China in the ESTEC scenarios



Key point: Up to 3.2 EJ but very scenario-dependent

Chapter 8.
CONCLUSIONS AND CHALLENGES AHEAD

HIGHLIGHTS

- No single energy technology, based on current prospects, offers the potential to be a "silver bullet" capable of curbing emissions and improving the security of energy supply. This applies both to hydrogen and fuel cells. Instead, a balanced RD&D approach is needed to develop a broad technology portfolio.

- Hydrogen and fuel cells can play a significant role in the future energy market if the current targets for reducing technology costs can be met in a timely manner and if governments enact new, concerted policies to mitigate emissions and limit oil dependency. Policies solely aimed at enhancing energy-security would not necessarily result in a transition to hydrogen. Other technologies and fuels (*e.g.* synfuels from coal) would be more cost-effective at increasing energy diversification in a CO_2-unconstrained world.

- Under most favourable assumptions, hydrogen and fuel cells will contribute to meeting the global energy demand in transport, with hydrogen fuel cell vehicles reaching up to 30% of the vehicle stock by 2050. Fuel cells can also help meet the demand for distributed CHP, with some 200-300 GW by 2050. The collective impact of a number of emerging technologies (including hydrogen and fuel cells) and appropriate policies could stabilise CO_2 emissions in the period 2000-2050 and help diversify the energy system.

- Development of a complete hydrogen supply infrastructure at this point in time is premature. Hydrogen and fuel cell research and demonstration are still at the development stage. The solutions to current technical issues and bottlenecks, such as better fuel cell performance and hydrogen on-board storage, may have a considerable impact on the choice of the technologies for hydrogen production, distribution and refuelling.

- Hydrogen and fuel cell RD&D efforts should focus on hydrogen production (cost-effective, CO_2-free hydrogen and better decentralised production technologies), fuel cells (cost reduction, durability, new materials and concepts) and on-board hydrogen storage. Emphasis should also be put on hydrogen transportation and distribution. Insufficient progress in reducing the cost and energy consumption of the technologies for hydrogen transportation and distribution – a precondition for centralised production – could have a negative impact on the future of hydrogen as an energy carrier.

- Some *high-risk/high-reward* technology options are presently at a very early stage of development. These technologies include photo-electrolysis, the biological production of hydrogen, water splitting by nuclear and solar heat, new materials for on-board solid storage, and new fuel cell concepts. Their prospects are presently unclear but they may potentially achieve significant breakthroughs with considerable impact on hydrogen and fuel cell applications, as well as on the overall energy system. The currently impressive advances in solid-state physics and materials science may also lead to unexpected and pleasant surprises in these R&D areas for hydrogen and fuel cells.

Previous chapters provided a detailed overview of the impact that potential technology advances, energy policies and other key drivers may have on the introduction of hydrogen and fuel cells in the energy market. R&D directions, infrastructure investment needs and the role hydrogen and fuel cells can play in curbing CO_2 emissions and improving energy supply security were a part of that discussion. This chapter builds on the main findings to discuss in more detail the policy insights emerging from the study.

Market prospects for hydrogen and fuel cells

New technologies may quickly conquer the market if they offer immediate benefits such as lower costs, superior performance or new, attractive services, even if they are costly. If this is not the case, if the new technologies offer "only" collective economic or social benefits in the mid to long-term at a higher cost than existing technologies, then they will need both government policies and "technology learning" to become economically competitive and enter the market. Government policies and technology learning driven by private investment hold important synergies and should act in concert in order to speed up market deployment.

At present, hydrogen and fuel cells appear to be a rather costly option to mitigate CO_2 emissions and enhance energy-security. Current prospects for cost reductions are unlikely to result in a significant economic advantage over existing technologies. Therefore, hydrogen and fuel cells are unlikely to emerge in future energy markets without decisive government policies and technology breakthroughs that reduce costs substantially.

In a business-as-usual scenario (*e.g.* BASE, see Chapter 5) with no substantial new policies for environmental protection and energy diversification, hydrogen and fuel cells do not play a significant a role in the future energy mix. Also, policies solely aimed at enhancing energy-security would not necessarily result in a transition to hydrogen. In a CO_2-unconstrained world, other technologies and fuels (*e.g.* coal) would be more cost-effective in increasing energy diversification.

Hydrogen may conquer a significant market share if effective policies for both CO_2 mitigation and energy-security are in place in conjunction with a considerable reduction in the cost of hydrogen and fuel cells.

For the sake of this study, these policies have been collectively represented by an economic incentive to curb CO_2 emissions. The incentive, expressed in USD per tonne of CO_2 emissions avoided, represents a variety of regulatory measures, subsidies and other policy instruments that promote hydrogen and other technologies with the potential to reduce emissions and improve energy diversification. All these policy instruments have the net effect of giving new technologies a value in terms of emissions avoided. For example, under realistic assumptions for technology advances, a CO_2 incentive that increased gradually up to USD 50/t CO_2 would stabilise emissions over the period 2000-2050 and halve the level of emissions in 2050 in comparison with the business-as usual scenario. The resulting energy mix would also be significantly more diverse.

The adoption of the CO_2 incentive paves the way for intense competition among a number of new technologies with the potential to gain market share. None of them seems to be able to play a dominant role in the future energy market (there is no "silver bullet" in energy technology), in comparison, for example, with the role played by oil in transport. However, their collective effect stabilises emissions and helps improve energy security by diversifying the energy system. Hydrogen and fuel cells are part of this broad technology portfolio.

In the most favourable, cost-optimal scenario (*i.e.* ESTEC D) – with the CO_2 incentive gradually increasing up to USD 50/t CO_2 and with quickly declining costs for hydrogen and fuel cells – hydrogen emerges as an important fuel in the transport sector beyond 2030. Some 12.5 EJ of hydrogen would be used in 2050, mostly in the transportation sector. While in absolute terms this appears to be a small amount of energy in comparison with a total primary energy supply of around 785 EJ, its impact on transportation is very significant. The efficiency of PEM fuel cell vehicles is such that some 30% (*i.e.* 700 million cars) of the global fleet of passenger cars would be fuelled by this relatively small amount of hydrogen in 2050. Fuel cell vehicles (cars, delivery vans, etc.) would start gaining market share between 2015 and 2025. In this scenario, if the hydrogen used as an energy carrier is added to the hydrogen used for other applications (refinery processes and chemicals), more than 22 EJ of hydrogen would be used in 2050. This amount represents more than a four-fold increase with respect to current hydrogen production.

Under less optimistic assumptions for technology development and policy measures, hydrogen and fuel cells are unlikely to reach the critical mass that is needed for a successful market uptake. Market introduction barriers and competing fuel and technology options, such as biofuels and Fischer-Tropsch (FT) synfuels, would play a more important role. However, in all scenarios with CO_2 incentives, the global oil trade is 30-50% lower in comparison with scenarios (*e.g.* BASE) without new CO_2 policies. This is a significant improvement in the security of energy supply, but it cannot be attributed to hydrogen and fuel cells alone.

The net benefit of hydrogen and fuel cells can be estimated if the most favourable scenario is compared to a similar scenario where hydrogen and fuel cells are not part of the technology portfolio. The net benefit of hydrogen and fuel cells is then a 5% reduction in CO_2 emissions (1.4 Gt CO_2) and a 2% reduction in oil use in 2050. This may appear as a limited benefit. However, if vigorous CO_2 policies are in place, the resulting fuel/technology mix would be optimised for emissions mitigation. In these conditions the absence of hydrogen and fuel cells allows a number of new, alternative technologies, such as biofuels, CNG and FT synfuels from coal and gas with CCS, to play a larger role in a competitive energy market. In such a diversified and optimised world, the role played by a single emerging technology is necessarily limited. Neither hydrogen nor other emerging technologies seem to be crucial to mitigating emissions in these scenarios, but their collective impact stabilises emissions. In the scenario without hydrogen and fuel cells, the 30% of passenger cars and light/medium trucks fuelled by hydrogen fuel cells in 2050 would be replaced by ethanol vehicles (about 10%) and gasoline advanced ICE, hybrids and natural gas-fuelled vehicles (the remaining 20%). The increased emissions from the additional FT synfuel production and the increased use of gasoline and natural gas for vehicles account for the total emission increase of 1.4 Gt CO_2 per year.

The impact on energy-security is also limited, *i.e.* a 2% reduction in total conventional and unconventional oil use in 2050. However, the presence of hydrogen would reduce oil imports from Middle East by 14% in 2050 and, significantly, would reduce the need for a rapid expansion of other oil substitutes in the transportation sector.

In all scenarios, stationary fuel cell capacity ranges from 200 GW to 300 GW by 2050. This result suggests that stationary fuel cells, namely solid oxide fuel cells and molten carbonate fuel cells, represent a robust technology option that is not significantly affected by policy strategies and other variables. Most such fuel cells would be fired by natural gas. However, up to 22% of all fuel cells would use oil refinery products in 2050. Hydrogen PEM fuel cells for stationary applications do not show up in any scenarios. This result can be explained by the cost of a dedicated hydrogen supply system, but also by the flexibility of the SOFC and MCFC systems, which do not need a fuel reformer, are less sensitive to poisoning than PEM fuel cells and have a superior conversion efficiency. Stationary hydrogen fuel cells, however, could benefit from the development of a hydrogen distribution system for transport, as this may lower the hydrogen supply cost. However, the implications of such a synergy have not been considered in this analysis.

Fuel cells for stationary use would concentrate in residential and industrial sectors and fill the market gap between large-scale CHP units and small-scale boilers. This would extend the economic feasibility of CHP to buildings with limited heat demand. Fuel cells for centralised power production play a role in only one scenario, in combination with coal fired IGCC plants. In this scenario some 25 GW of IGCC-SOFC plants are installed world wide by 2050.

In cost-optimal scenarios, hydrogen production in the early market uptake phase is primarily based on decentralised natural gas reforming and electrolysis. Centralised production from coal and natural gas with CO_2 capture and storage plays a major role in the long term. The need for decentralised production increases the cost of hydrogen during the transition phase. In the early market introduction phase, the limited demand for hydrogen does not justify the construction of an extensive distribution infrastructure and there is insufficient demand to operate large centralised production units continuously. In these scenarios, production from nuclear and renewable energy does not appear to play a significant role. However, the cost of hydrogen production from nuclear heat or from biomass could be only slightly higher than hydrogen from fossil fuels. If so, nuclear and renewable hydrogen could enter the production mix on a significant scale, especially if production cost is not the only criterion for the selection of the hydrogen production technology, or if technologies for CO_2 capture and storage face unexpected problems.

If ambitious climate and energy-security policies are adopted, the regional potential for hydrogen and fuel cells seems to be high in the OECD regions and in China. In all regions, transport applications (hydrogen fuel cell vehicles, FCVs) dominate the hydrogen market. The share of hydrogen FCVs varies widely across regions. In the most optimistic scenario, the region with the highest FCV stock share by 2050 is actually China (60%), followed by India, which has up to 42% hydrogen FCV share in 2050. A leap-frogging effect may occur in these countries as they have limited existing infrastructure for transport fuels already in place. Their large indigenous coal reserves, potentially available for hydrogen production, may also facilitate a transition to hydrogen. This result, however, is highly scenario-dependent. The share of FCVs in OECD countries is somewhat more stable across scenarios, although there is significant variation between regions. Under the most favourable assumptions, it ranges from 10% in Australia to 22% in Japan, 35% in Canada, 36-48% in Europe and 42% in the United States. Hydrogen use in other regions is negligible.

Hydrogen use starts around 2015-2020 in Europe and North America, and around 2025 in the other regions. This relatively narrow window in which uptake in various regions occurs suggests that conditions for hydrogen introduction exist in different economies and geo-political areas. Differences in hydrogen penetration across regions may be explained by different economic conditions, discount rates, availability of infrastructure, citizen attitudes to investment in capital-intensive technologies, energy and fuel taxes, and mobility needs. In absolute terms, hydrogen use in the OECD Pacific appears to be significantly lower than in the other OECD regions. However, in terms of per capita use, the difference is much smaller. The remaining difference can be explained by the lower energy intensity in key countries of the OECD Pacific area (particularly Japan) and the lower annual car-mileage. In comparison, current North American per capita oil product use is a factor 2.2 to 2.6 times higher than in Europe and the OECD Pacific regions.

Technology prospects

Hydrogen technologies

Hydrogen can contribute to energy security and the diversity of the energy supply as, in principle, it can be produced from all primary energy sources, using a number of different processes. Hydrogen produced from renewables, nuclear energy and from coal or natural gas, with CO_2 capture and storage, results in hydrogen that is a CO_2-free energy carrier and offers considerable potential for emissions mitigation.

Hydrogen for refinery and industrial uses (some 40 million tonnes a year, equivalent to 5EJ) is currently produced via established technologies, primarily natural gas reforming, but also coal gasification and water electrolysis. However, to produce cost-effective hydrogen for energy use, these technologies need higher efficiency, significant cost reductions and the development of cheap and safe techniques for CO_2 capture and storage. RD&D efforts are focused on high-efficiency gas reforming, coal gasification in IGCC plants and electrolysis at high temperatures and pressures. Solar and nuclear heat to split water, biomass gasification, and photo-biological processes are also being developed. These technologies, although at different levels of development, are all still far from market introduction.

Small-scale, decentralised natural gas reforming (without CO_2 capture) and electrolysis appear to be the technologies of choice to produce hydrogen in the early market introduction phase. Most current RD&D is focused on decentralised production technologies, as they do not require costly infrastructure for hydrogen transportation and distribution. However, decentralised technologies generally have a low efficiency and need substantial cost reductions if they are to become competitive. In addition, a fundamental disadvantage of decentralised natural gas reforming installations is that the capture of CO_2 emissions in small plants is difficult and expensive, and hence not likely to be feasible. As far as electrolysis is concerned, current and projected costs are even higher than those for decentralised natural gas reforming. In addition, prospects for producing hydrogen from renewable electricity are limited, even in the long term. While a substantial part of the electricity supply may be based on renewables by 2050, the availability of surplus renewable electricity for hydrogen production will probably be limited to a few world regions.

The current cost of hydrogen from decentralised production may exceed USD 50/GJ H_2, but various centralised production options promise hydrogen at USD 10-15/GJ H_2. Though sensitive to natural gas and electricity prices, the cost of natural gas reforming may be reduced to less than USD 15/GJ H_2 by 2030 and that of electrolysis to below USD 20/GJ H_2. Even lower – below USD 10/GJ H_2 – is the projected cost of hydrogen from coal gasification in centralised IGCC plants with CO_2 capture. The long-term costs of hydrogen from high-temperature water splitting could be USD 10/GJ H_2 using nuclear heat and USD 20/GJ H_2 using solar heat. Higher costs are projected for other technologies. However, the less developed the technology is at the present time, the higher is the uncertainty regarding the projected production costs.

Hydrogen can fuel combustion engines and turbines, but it offers its full benefits in terms of higher efficiency and reduced CO_2 and other pollutant emissions when used in fuel cells. The use of hydrogen FCVs could solve the problems of the oil-dependence and emissions mitigation in transport at the same time. Stationary residential uses and power generation are also attractive fuel cell applications, especially in situations where combined heat and power (CHP) systems are needed.

Hydrogen on-board storage for fuel cell vehicles is a key RD&D issue, since on-board hydrocarbon reforming has proved to be difficult. Unfortunately, existing on-board storage options do not yet meet the technical and cost targets needed to be competitive. Gaseous storage at 350-700 bar and liquid storage at -253 °C are commercially available, but remain costly and energy intensive options. The cost of the hydrogen tank is around USD 600-800/kg H_2 and the electrical energy required for compression and liquefaction is more than 12% and 35% of the hydrogen energy content, respectively. Solid storage may offer potentially decisive advantages, but it is still at an early stage of development, with a number of materials being investigated. The promising characteristics of carbon nano-structures have not been confirmed. Without further breakthroughs, gaseous storage at 700 bar seems the technology of choice for passenger cars at present. However, such a system would not meet the required targets for cost and performance. The global character of the car industry is such that on-board storage technologies, as well as hydrogen quality and safety standards, must be established before the deployment of the full-scale hydrogen infrastructure. Indeed, the choice of on-board storage system may have a significant impact (*e.g.* hydrogen pressure) on the choice of the optimal hydrogen infrastructure (production, distribution and refuelling). Therefore, the identification of a suitable and cost-effective storage technology is an urgent issue to bring hydrogen to the market.

In the case of centralised hydrogen production, the cost of hydrogen transportation and distribution, and the refuelling stations, add considerably to the total hydrogen supply cost. These costs range from USD 5/GJ to 10/GJ of hydrogen for large-scale supply systems; however, they may be even higher during the initial development phase. Hydrogen transportation by pipeline seems to be the least-costly option to move hydrogen. However, because of the low gas density and its highly permeable nature (it requires less permeable materials than does natural gas), hydrogen pipelines are five times more expensive in terms of energy needs as natural gas pipelines and twice as expensive in terms of investment in materials and equipment. The transportation and distribution of liquid hydrogen is even more expensive, and may not be practical for large quantities of gas.

Estimating the global investment required for hydrogen infrastructure is a difficult exercise. For example, whether current natural gas pipelines may be used to transport hydrogen is still a matter of discussion. At the very least, adaptation or replacement of some materials and components would be required. The cost of the hydrogen supply infrastructure needed for road transport would be in the order of several hundred billion US dollars. If centralised production is adopted, the cost of a hydrogen pipeline supply system for the transport sector would range from USD 0.1 to 1 trillion. The *incremental* investment cost for hydrogen refuelling stations would be somewhere between USD 0.2 trillion and USD 0.7 trillion for centralised and decentralised production respectively. A full hydrogen economy (extensive hydrogen use for both transport and stationary applications) would require pipeline investment in the order of USD 2.5 trillion, the bulk of which would be needed for the connection of commercial and residential customers. Assuming early retirement and partial replacement of the existing natural gas supply system, a significant part of this cost would be an *incremental* cost.

While these investment costs are very significant, their order of magnitude is not inconsistent with the USD 16 trillion investment that would be required for the overall energy supply system until 2030 according to the *World Energy Outlook* Reference Scenario (IEA, 2004a). Even considering the uncertainty affecting current estimates, it appears that the cost of a transition to hydrogen would add substantially to the total investment required in the energy system (from a few percent to some tens of percent). In absolute terms, however, the hydrogen investment should be considered as a deterrent to the transition to hydrogen. It would be relatively affordable if compared to the global (undiscounted) world GDP over the period to 2050-year (some 5 350 trillion USD) and to the total investment in terms of percentage of the GDP, *i.e.* some 23% of the global annual GDP. Who should bear this investment cost is, of course, an important matter for future discussion.

Fuel cell technologies

Fuel cells are the technology of choice to exploit the full benefits of hydrogen in terms of energy-security, emissions and efficiency.

Proton exchange membrane fuel cells can be used for both stationary and transport applications. Because of their high sensitivity to carbon monoxide and sulphur pollutants, they need to be fuelled by a pure hydrogen (*e.g.* produced by electrolysis). If hydrogen from natural gas reforming or from residual industrial gases is used, purification is needed before use. At present, PEMFCs seem to be the best technology candidate for fuel cell vehicles. The current cost of PEMFCs exceeds USD 2 000/kW, but a reduction in stack costs to USD 100/kW seems to be achievable by mass-production and technology learning. However, further reductions to below USD 50/kW will be needed to produce FCVs that are competitive with ICEVs. This will require fundamental advances in materials, higher fuel cell power densities and attention to elements of the fuel cell engine other than the fuel cell stack. Research is focusing on high-temperature membranes that are less prone to poisoning and enable on-board reforming. Because of these ongoing developments in PEM fuel cell technology, it would be premature to make choices now about the hydrogen infrastructure, as they will depend on the hydrogen purity requirements of PEMFCs. Direct ethanol fuel cells could also become an attractive option for transport applications, but they are still at a very early stage of development.

Hydrogen FCVs are at least twice as efficient as a current "reference" ICE car. However, FCVs are not yet ready for commercialisation. In addition to fuel cell stack cost reductions, they need improvements in their durability and reliability. Other components such as the cost of the balance of plant, electric drive and hydrogen storage system, also determine the FCV cost, but have received less attention so far. Assuming that the cost of PEM fuel cell stacks decline to USD 35/kW in 2030, then the FCV *incremental* cost in comparison with a conventional ICEV would be USD 2 200 per vehicle, or USD 7 600 if the cost only fell to USD 75/kW. The global *incremental* cost for some 700 million FCVs that could be sold by 2050 would then have a range from USD 1 to 2.3 trillion.

Drive systems for fuel cell passenger cars could be competitive at costs of USD 50-100/kW. However, high-mileage vehicles are niche markets that could support higher fuel cell costs. For example, FC buses could be competitive with a fuel cell stack cost of USD 200/kW, delivery vans at USD 135/kW and forklifts at USD 100/kW. Buses could in principle be the largest and most promising market. Although current production volumes are very small (some 10 buses a year), market developments could drive increasing production volumes and significant declines in PEM stack costs. Following this cost reduction, PEM fuel cells could be introduced into passenger cars as well. However, recent estimates based on ongoing demonstration projects suggest that the fuel efficiency of fuel cell buses could be only 20% higher than diesel ICE buses. Moreover, diesel-hybrid buses are emerging as a serious competing option. However, stringent local air pollutant standards could encourage the use of hydrogen fuel cell buses.

Molten carbonate fuel cells and solid oxide fuel cells are the best candidates for stationary applications. They are less sensitive to pollutants than PEMFCs. Current MCFCs are fuelled by natural gas, while SOFCs can be fuelled by both hydrocarbons and pure hydrogen. Both MCFCs and SOFCs operate at high temperatures and do not require external reformers. Their electric efficiency is higher than that of PEMFCs, but they cannot be used for cars because of their high operating temperature, which results in long start-up times. MCFCs seem best suited for large-scale systems, while SOFCs could also be used on the scale of single-family dwellings.

Stationary fuel cells could fill the market between large-scale CHP units and small-scale boilers, extending the economic feasibility of CHP to the scale of individual buildings. Decentralised power generation without heat production seems to be less attractive, as the efficiency of fuel cells would be lower than for other centralised electricity generation technologies, even if distribution losses are accounted for. In CHP applications stationary fuel cells may achieve overall efficiencies higher than 85%, but electric efficiencies of 60% are still a challenging target for stationary fuel cell systems. Stationary fuel cells can bear higher costs (USD 700-1000/kW) than those for mobile applications, due to the higher load factor achieved and the higher cost of competing options. Their costs are expected to decline by a factor of 5 to 10 through mass-production and technology learning, thus becoming competitive. Both the fuel cell stack (50% of the cost) and balance of plant need cost reductions.

Direct methanol fuel cells use methanol as a fuel. They are the best candidates for portable applications, but their low efficiency is likely to preclude their use in mobile and stationary situations. However, other fuel cell types, *e.g.* direct ethanol fuel cells, may benefit from technology learning spill-over effects (membranes, mass-production technologies, etc.). In contrast, PEMFCs are not practical for portable devices, because of hydrogen storage problems, nor are MCFCs and SOFCs, because of their high operating temperature. In terms of commercial maturity, portable DMFCs appear close to market introduction. They are likely to be followed by stationary MCFCs and SOFCs systems for decentralised use. More time is needed for the commercialisation of mobile PEMFCs, although they are urgently needed to meet environmental and energy-security objectives.

Competing options

Hydrogen and fuel cell technologies compete with many other alternative fuels and technology options that can be applied to meet energy-security and environmental goals.

In the transportation sector, hydrogen FCVs face a chicken-or-egg problem, in that little demand is likely without the infrastructure to provide cheap hydrogen, but the investment in this expensive infrastructure is unlikely without significant demand. Various other technologies and fuel options do not face similar barriers to introduction. Major competing options include biofuels, CNG, FT synfuels from coal and gas, hybrid ICEs, and plug-in hybrid vehicles. Biofuels are a short-term, low-cost fuel alternative in the transport sector. More efficient advanced ICE engines and hybrid vehicles, using gasoline or diesel, could also represent a viable alternative to hydrogen FCVs, but they would not yield the same reductions in emissions. Hydrogen-hybrid vehicles face the same on-board storage issues as FCVs and a similar chicken-or-egg problem applies, but they do not require the same challenging cost reductions for the drive system.

For both stationary and mobile applications, competing options are also energy efficiency measures and large-scale electrification based on coal with CCS, nuclear, or renewable and nuclear energy. Large-scale electrification in conjunction with plug-in hybrid vehicles and Li-ion batteries could also lead to the role of electricity in the transport sector being reconsidered.

The competition in stationary applications – either distributed electricity generation or cogeneration – is also intense. Centralised, highly efficient coal and gas-fired power plants with CCS, emerging renewable technologies, and new nuclear power plants are strong competitors that all distributed technologies have to beat. At the same time, new technologies such as micro-turbines and Stirling engines are being introduced for combined heat and power cogeneration. Enhanced building insulation and energy efficiency programmes in industry may also limit the future demand for heat. On one hand the reduced demand for heat limits the potential for stationary fuel cells, but on the other hand, an increased power-to-heat ratio makes fuel cells more attractive in comparison with other CHP technologies.

The analysis in this study suggests that an assessment of the potential of hydrogen and fuel cells without taking into account competing options would lead to misleading conclusions and could result in an overly optimistic assessment of hydrogen's potential.

Uncertainties regarding hydrogen and fuel cell prospects

Hydrogen and fuel cells can play a role in the energy sector under a range of future conditions that are subject to significant uncertainties. Key factors can be split into three areas: economic conditions, energy policies and market developments; future developments in hydrogen technologies; and the role of competing options to meet policy targets.

A limited number of factors have a positive effect on the future use of hydrogen, while most of them have a negative effect. The sensitivity analysis indicates a maximum variation of ± 80% in hydrogen use when individual drivers are varied. Factors with major impact are CO_2 and energy-security policies; future FCV costs and performance; the severity of chicken-or-egg transition problems; timely development of a centralised hydrogen production and distribution infrastructure; and consumers' criteria for buying cars. Future oil supply issues (quantities and prices) are obviously of primary importance. Competing technologies also play an important role that is not very sensitive to their technical characteristics. Also, specific measures aimed at enhancing energy security do not have a major impact if substantial CO_2 policies (*e.g.* CO_2 incentives) are already in place.

However, major uncertainties concern whether and how these factors will materialise, rather than their individual impact on the potential of hydrogen and fuel cells. For example, reaching international agreement on concerted measures to curb emissions and enhance the security of energy supplies is a difficult and time-consuming business. Similarly, the future prospects for coal-based cogeneration of hydrogen and electricity may be affected by higher than expected costs and poor social acceptance of the CO_2 capture and storage technology. Strong developments in nuclear and renewable energy may enhance the prospects for CO_2-free hydrogen and hence fuel cells. However, they could also weaken the prospects for hydrogen and fuel cells by making available large quantities of cheap and CO_2-free electricity and biofuels, which would then compete as alternative options to mitigate emissions and enhance energy-security.

In the transport sector, uncertainties concern not only the choice of PEMFCs materials, the on-board storage system, and the choice between hybrid ICEVs and FCVs, but also who will bear the large investment in hydrogen production, distribution and refuelling infrastructure. At present, it is unclear what the incentive would be for major oil companies and electrical utilities to invest in hydrogen infrastructure, unless clear government policies are established.

Also, the rate at which production can expand is an important issue for the policy timing and the speed of the transition. Current cumulative FCV production stands at about 600 vehicles, compared to annual car production of some 50 million vehicles. At this moment, no car maker has plans to mass-produce hydrogen-fuelled vehicles. Producers will initially offer a single model in a single country to explore market acceptance, and will then gradually expand into other regions. Past experience from various industrial sectors may be of interest. Introduction of hybrid vehicles took a decade to achieve 0.5% of the market. The semi-conductor industry (which faces no competition) has been growing at some 15% per annum over the period 1960-2000. At such a high growth rate, the market for FCVs would increase from 0.5% to 30% in 30 years.

How fast the production volume will grow is also important for technology learning and the rate of cost reductions, and for setting public support policies. Should the introduction of hydrogen be supported by public incentives in the early market introduction phase, the level of the financial support will depend strongly on how rapidly technology learning can make hydrogen economically competitive.

RD&D challenges and opportunities

Current public spending on hydrogen and fuel cell RD&D, at USD 1 billion a year, is substantial if compared to the total annual budget for energy RD&D of around USD 8 billion. However, present efforts are small in comparison with the investment needed to support the introduction of hydrogen technologies into the energy market. This would imply a landslide change in government energy policy, with a dominant emphasis on technology innovation. In an ideal case, governments should first establish credible and long-term energy-security and environmental policies and targets, without which no reason exists to switch to hydrogen. They should then foster the establishment of international standards for hydrogen and fuel cells in close consultation with industry, promote infrastructure investment, and provide incentives for consumers to adopt new technologies. An important part of the policy strategy could be the use of government procurement programmes (*e.g.* for car fleets) to help promote technology learning and early introduction into niche markets. However, past and current trends for energy RD&D budgets run contrary to the need for an even greater effort to introduce hydrogen and fuel cells. Government energy RD&D budgets have been falling in recent decades and, according to IEA statistics, the total energy RD&D expenditure in 2002 of just under USD 8 billion was only 50% of the 1980 value.

In the transportation sector, the current private RD&D investment exceeds public investment. Industrial strategies, however, vary considerably. DaimlerChrysler and Ford rely on Ballard fuel cells; General Motors (GM), Honda and Toyota are developing their own fuel cells. GM is developing the skateboard chassis FCV concept. DaimlerChrysler is focusing on fuel cell vehicles and bus test fleets. Nissan is already leasing FCVs to private customers for demonstration purposes and Honda is aiming to do so by the end of 2005. Ford and Mazda are also working on hydrogen ICE vehicles. BMW is working on hydrogen ICEs with fuel cells for the auxiliary power unit. Toyota is following a phased approach, first commercialising its hybrid vehicles and subsequently aiming at integrating fuel cells into the hybrid concept. A number of other car companies not only focus on hydrogen, but also on other solutions such as biofuels (*e.g.* Volkswagen, Peugeot-Citroën). Several new players are trying to enter the car market using revolutionary fuel cell engine technologies. This range of approaches indicates that there is no clear optimal strategy to get hydrogen and fuel cells to the market.

The initial target for market introduction in 2004 has subsequently been moved to 2010. Some major car makers are now talking about introduction after 2012 (Adamson, 2005) and other companies envisage commercialisation after 2020. This suggests that achieving the target of replacing conventional vehicles and fuels to curb emissions and improve energy-security is proving to be more challenging than expected, and that different visions exist on how to get there.

The timely meeting of the most ambitious targets for technology improvement (performance and cost reductions) appears as an essential pre-condition for the success of hydrogen and fuel cells. Delays in technical progress could result in other technology paths that are closer to commercial maturity being "locked-in" ahead of hydrogen.

The discussion of hydrogen and fuel cell technologies in this analysis presents a wide range of possible options, from market-ready solutions to theoretical concepts. While selecting winners is premature, identifying technologies that may become important in the short-term and those that are further away from market introduction is an important part of setting RD&D priorities and investment.

There are some low-risk/low-surprise options, such as natural gas reforming, water electrolysis, coal gasification, high-pressure gaseous storage, improved fuel cell balance of plant and manufacturing technologies, hydrogen burners for gas turbines, and hydrogen ICEs. What these technologies may offer, and their possible future developments, are already rather well delineated. There are also technologies with large margins for improvement, such as new materials for PEM membranes and catalysts. Other broader technologies will have a potential impact not only on hydrogen and fuel cells, but also on the wider energy sector, *i.e.* CO_2 capture and storage. A different category is the high-risk/high-reward options such as photo-electrolysis, biological production, water splitting by nuclear and solar heat, on-board solid storage, and new fuel cell concepts. If successful, some of these technologies may represent major breakthroughs in energy technology, with tremendous impacts on the future applications for hydrogen and fuel cells, and on the wider energy system. At present, most of these options are in a very early stage of development and the data available on their potential performance and costs are too uncertain to conduct a quantitative analysis. Therefore, they have not been included in this study. However, a balanced RD&D investment strategy based on costs/benefit criteria should take into account these technology options.

Taking a slightly broader view, it should be taken into account that relevant RD&D work for hydrogen and fuel cells does not need huge single investments, such as other centralised energy technologies (*e.g.* nuclear fusion), to improve their prospects. As a consequence, RD&D activities are carried out in both small and large public/private laboratories and research organisations. In principle, with such a huge number of opportunities and economic attractiveness, some technology solutions could already be in the infancy stage of their development, or even available in industrial labs, pending patent applications or in the expectation of a future market start-up. In addition, many aspects of hydrogen and fuel cell RD&D deal with developments in solid state physics and materials science. These booming disciplines promise tremendous advances with potentially broader impact on technology, including unexpected and pleasant breakthroughs in hydrogen and fuel cells.

Annex 1
ETP MODEL CHARACTERISTICS

In order to quantitatively assess the merits of hydrogen and fuel cells in relation to other technology and policy options, the IEA has used an in-house tool known as the Energy Technology Perspectives (ETP) model. This enables the benefits of technology options, including hydrogen and fuel cells, to be analysed in a structured, logical manner.

This annex provides an overview of the structure and scope of the ETP model, and the assumptions that lie behind the analysis. Given the large size of the model, only its general structure is outlined, followed by a discussion of the key parameters that affect hydrogen and fuel cells. This annex will be of interest to those wishing to understand the quantitative analysis that lies behind the results provided in Chapters 4, 5, 6 and 7.

The value of the ETP model in the analysis of technology prospects

The ETP model belongs to the MARKAL family of bottom-up systems engineering models (Fishbone and Abilock, 1981; Loulou *et al.*, 2004). The MARKAL model framework has been developed during the past 30 years by the Energy Technology Systems Analysis Programme (ETSAP), one of the IEA implementing agreements.

A model is a structured, logical and reproducible method used to analyse a complex policy problem. Given that it is not possible to predict the future with any certainty, the goal of the exercise is to "model for insights", not to "model for figures". Every model is a simplified representation of a system or market, in this case the global supply and demand of energy, and will be based on a set of data that approximates the real world. Each model has its own unique characteristics that affect the results and conclusions.

The ETP model is a complex model. Using it to analyse the prospects for hydrogen and fuel cells requires a significant expenditure of resources. However, this complexity and the level of effort required to make it work is needed if a robust assessment of the prospects for different technologies is to result. The reason is that this framework accounts for a large number of key characteristics of the energy system that are of importance for long-term decision making. If these characteristics were not accounted for, the outcome of the analysis may not accurately reflect the complex interactions in the global energy system and in all likelihood would be less relevant for decision making. The model has the following characteristics, some of which are elaborated on in more detail:

- The model splits the world into 15 regions.[22] This allows an accurate representation of the specific characteristics of the energy system at a regional level, *e.g.* the availability of primary energy sources, the acceptance of nuclear, the regional availability of capital, etc.
- The model optimises the energy system for the next 50 years. Such a long-term perspective is needed in order to properly assess the role of hydrogen and fuel cells.
- The model provides insights concerning the effect of deploying hydrogen and fuel cells on global fossil fuel and electricity markets, an issue that has received limited attention so far.

22. The 15 regions considered in this study are: Africa, Australia/New Zealand, Canada, China, Central and South America (CSA), Eastern Europe, the Former Soviet Union (FSU), India, Japan, Mexico, Middle East, Other Developing Asia (ODA), South Korea, the US and Western Europe.

- The model accounts for competing emission reduction strategies in certain sectors. For example, hydrogen and fuel cells compete with renewables and energy efficiency options to achieve the least-cost emissions reduction.
- The model provides a dynamic assessment of the interactions between competing options. For example, the use of more hydrogen from fossil fuels with CCS may reduce but not displace entirely the use of biofuels. This provides a more accurate assessment of the marginal benefits in terms of emissions reduction of using hydrogen than a back-of-the-envelope calculation where gasoline and hydrogen cars are compared.
- Emerging hydrogen and fuel cell technologies are explicitly modelled.
- The model contains a database of current and emerging technologies. Therefore the assessment of hydrogen and fuel cells is not based just on the current energy system, but also on the possible characteristics of the future energy system. This is of vital importance to the analysis if significant changes in the energy system are anticipated, such as might occur if CO_2 policies are strengthened.
- The representation of technologies in the model is based on detailed data. These data are drawn from engineering studies and scientific literature. This detailed technology description enables the identification of technology RD&D opportunities. This is an advantage of the ETP model over econometric top-down models with very aggregate representations of technology that do not allow assessments of technology development prospects and the identification of RD&D opportunities.
- The model contains detailed representations of energy efficiency options and renewable energy costs and availability. This is essential to determining the marginal abatement costs of both options.
- The model explicitly takes into account capital stock turnover, which is critical in assessing the real world rate at which new technologies can penetrate the energy system.
- The model includes a detailed representation of electricity supply and demand, accounting for the difference between base-load and peaking plants, and the intermittent nature of some renewables. The annual electricity load curve is calculated by region, based on the demand for useful energy. The load of individual power plants varies over the year and over the life of the plant, depending on demand and installed capacity. CHP is represented in detail, with a seasonal heat load curve. This detailed representation of the electricity system is of key importance for the assessment of fuel cells and hydrogen production from electricity.
- The model takes into account carbon leakage (*e.g.* if industry relocates) and the regional effects on the energy system due to regional differences in CO_2 policies.

The representation of the energy system in the model

The ETP model is a micro-economic representation of part of the world economy, divided into 15 regions. The model is not a general equilibrium model; only the energy sector is modelled. The model covers the production of primary energy carriers (*e.g.* coal), their conversion into final energy carriers (*e.g.* gasoline) and the conversion of final energy carriers into useful energy, or "energy services" (*e.g.* lighting). This energy system (Figure A1.1) is modelled as a set of inter-dependent technical product flows and processes.[23] Various technologies can be used to generate certain product flows,

23. Models of this type, which start from descriptions of technical options, are often called "bottom-up" models in comparison with "top-down" models that start from a description of the economy as a whole.

e.g. a number of coal and gas-fired power plant types for electricity production. The model includes a technology database of around 1 500 supply and demand technologies.

The ETP model is a linear programming model that minimizes an objective function. This objective function represents the total discounted energy systems cost over a number of periods that satisfies a certain energy demand, given certain constraints (*e.g.* the availability of certain technologies). The model solution represents the equilibrium that would be achieved in a market characterised by perfect competition and therefore, according to neo-classical economics, would maximise societal welfare. The model version used for this analysis has a fixed demand profile for energy services and does not respond to price differences in scenarios. Other versions exist where the useful energy demand responds to price changes. However, for this analysis this additional complexity is not needed because other technology factors determine the prospects for hydrogen and fuel cells.

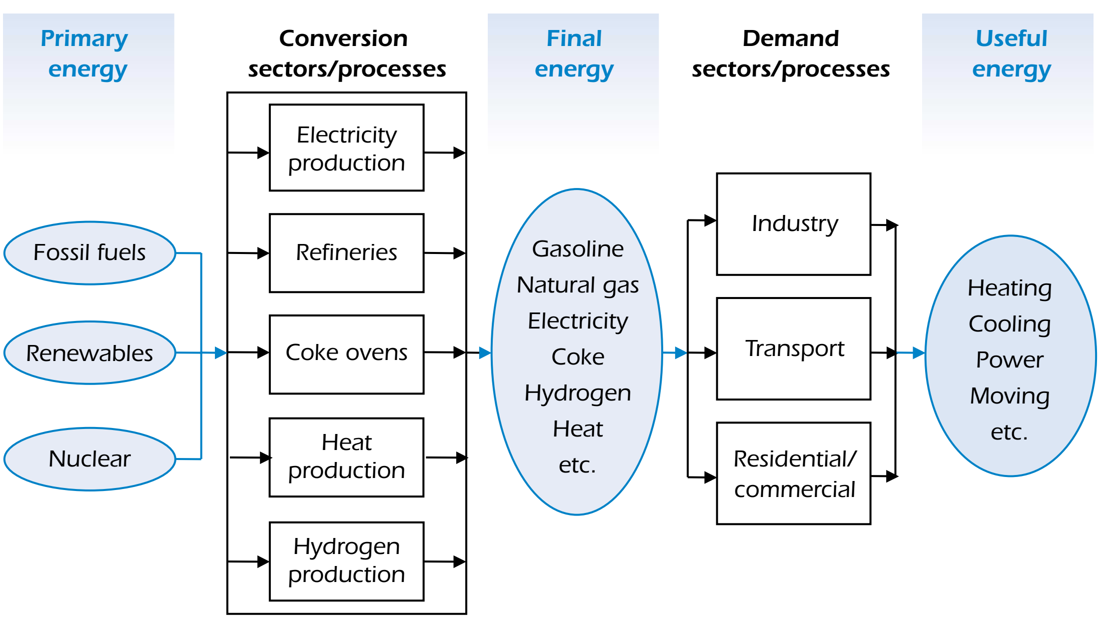
The model's choice of process technologies and activity levels determine the physical and monetary flows within the energy system. The model solution consists of a set of process activities, flows and the resulting emissions (the so-called "primary solution" in linear programming) and prices (the so-called "dual solution").

The strength of these types of models is that they are good at assessing long-term investment decisions in complex systems where future technologies are different from today's technologies. Moreover, the single objective function ensures that the resulting scenario is internally consistent, as the decision-making criteria for all processes and flows are the same.

On the other hand, these types of models have no explicit representation of macroeconomic factors. There are no feedback links that quantify the effects of changes in the energy system on the structure of the economy and economic activity. However, in most developed economies these impacts are of secondary importance as long as any changes are gradual.

Figure A1.1

The ETP model energy system



Black boxes known as "processes" or "technologies" are the building blocks of a MARKAL model. They are characterised by their:

- Physical inputs and outputs of energy.
- Cost and life-span.
- Other characteristics, such as environmental impacts (in this study CO_2 emissions).

Implicitly these process descriptions yield a very detailed input-output structure linking hundreds of inter-dependent processes through flows of energy intensive materials and energy. The model covers all major processes and energy chains "from well to wheel" (Figure A1.1). The model structure is capable of providing a dynamic life-cycle analysis of both energy and materials if adequate input data for individual technologies is available.

Process descriptions follow a standard format consisting of two data sheets. One sheet describes the physical inputs and outputs (of energy and materials), while the other describes the economic characteristics and any remaining process data. Data for different processes and technologies may be represented in different units, *e.g.* per kW for power plants and per tonne for a material product.

A schematic example of the model's input structure for conversion processes is shown in Table A1.1. The input data for the period 2000-2050 is provided at five year intervals, while one column is reserved for time-independent variables (TID). The physical data covers all the relevant physical inputs and outputs, *e.g.* of energy products and materials, as well as emissions of all the relevant greenhouse gas (GHG) emissions (CO_2, N_2O, CH_4). The GHG emissions are expressed in terms of their CO_2 using a 100-year global warming time horizon. The process data do not represent the total mass and energy balance, because some flows of less interest are not accounted for (*e.g.* low temperature waste heat).

Table A1.1

Example of the MARKAL model data structure for a power plant

	Period	Unit	TID	2000	2005	2010	...	2050
Sheet 1								
Physical flows								
Inputs	Fuel	(GJ/GJel)		2.0	1.9	1.8	...	1.7
Output	Electricity	(GJ)		1	1	1	...	1
Sheet 2								
Other data								
	Investments	(USD/kW)		1000	800	700	...	600
	Fixed annual costs	(USD/kW.yr)		5	5	5	...	5
	Variable costs	(USD/unit)		2	2	2	...	2
	Delivery costs	(USD/t A)		1	1	1	...	1
	Availability factor	(unit/unit cap)		0.9	0.9	0.9	...	0.9
	Peak contribution	(kW/kW)		1	1	1	...	1
	Life	(years)	25					
	Start	(year)	2000					
	CO2 emitted	(kg/GJel)		15	15	15	...	15
	CO2 captured	(kg/GJel)		150	135	120	...	105
	Residual capacity	(GW)		2	0	0	...	0
	Maximum capacity	(GW)		5	10	50	...	50
	Minimum capacity	(GW)		0	0	0	...	0

In order to optimise investment and the operation of particular technologies, the data sheet distinguishes between three cost categories:

- Investment costs - which are proportional to the installed capacity.
- Fixed annual costs – which are proportional to the installed capacity.
- Variable costs – which are proportional to the production volume.

Regional cost multipliers and discount rates are applied in order to reflect the different economic conditions around the world (see Annex 2).

The input data is not fixed over the projection period. For instance, increasing process efficiency can be modelled by decreasing inputs per unit of output (*i.e.* the declining fuel input needed in Table A1.1). This provides one way to account for "technology learning", as investment costs can be reduced over time as the installed capacity increases. A more complex alternative is where "technology learning" is endogenised and costs are calculated by the model as a function of cumulative investment. This approach has not been applied in this study.

Bounds

The user of the model can impose restrictions on the deployment of certain technologies. Such restrictions (called "bounds" or constraints) may reflect consumer or political preferences, intentions or objectives expressed in policy papers, or physical constraints such as natural resource availability.

This study includes a number of different types of constraints, including bounds on the maximum penetration of certain technologies due to resource constraints and even social or strategic considerations (*e.g.* a maximum level of nuclear and hydro capacity, a maximum level of natural gas imports from Russia into the European Union, etc.). They can also affect the rate of penetration of certain technologies to allow for the time needed to commercialise certain technologies (*e.g.* the necessary time for building pilot plants and plant construction). Some constraints reflect the starting capacity from earlier periods (*e.g.* for the existing building stock).

The ETP model matrix contains 750 000 rows, 950 000 columns and 5 000 000 non-zero variables. Given the size of the model, it is not possible to discuss all the input data in detail. Key modules that affect the hydrogen and fuel cell technology choice will, however, be discussed in more detail.

Demand categories

Processes represent all activities that are necessary to provide certain products and services, such as room space to be heated or vehicle-miles to be traveled. Many products and services can be generated by a number of alternative (sets of) processes that feature different costs and different GHG emissions.

The main end-use sectors currently contain 106 different "demand categories". The number of categories by end-use sector are presented in Table A1.2. For each demand category, energy demands are specified in terms of the energy service demanded (*e.g.* vehicle kilometres).

Table A1.2

Demand categories in the ETP model

Sector	Number of demand categories
Agriculture	1
Services	17
Power plants (own use)	1
Industry	46
Non-energy use	7
Residential	19
Transportation	15
Total	106

As ETP is a global model, it covers trade in energy and industrial commodities, but only models the value of trade. This approach explicitly allows for carbon leakage effects due to changes in the pattern of global commodity trade.

The BASE scenario's GDP growth (see Annex 3) and electricity demand are calibrated as closely as possible to the Reference Scenario of the World Energy Outlook 2004 (IEA, 2004a), but it is virtually impossible to achieve a 100% match. ETP demand is defined in useful energy terms, and ETP final and primary energy demand is the result of the technological options used, efficiency trends and cost optimisation. This is in contrast with the WEO model, which is an econometric model where the projected final energy demand is predominantly based on econometric models. The very different nature of both modelling approaches will result in different outcomes. The ETP model will tend to show lower energy use, as it does not account of market imperfections and it contains optimistic assumptions regarding technological change. The two different models complement each other, while having different strengths and weaknesses.

Future technology characteristics: a key uncertainty

Any analysis of future trends in the energy sector will be based on technology data from different sources. This data is likely to vary in terms of accuracy, while it will often not be clear which data is the most reliable. Generally speaking, studies about the prospects for new technologies will often suggest the potential for significant improvements in their cost and performance. However, the data on which these conclusions are drawn is inevitably uncertain and many new technologies do not make it to the market. In a least-cost planning model with perfect foresight, such as ETP, this uncertainty is not accounted for.

There is the always the possibility that risky, speculative technologies are selected instead of less attractive, but proven technologies. Such technology optimism can create modelling results that suggest radical technological change is possible. Considering only proven technologies can increase the credibility of the study, but at the risk of missing valuable insights into different policy choices. The answer is to try to ensure that the model contains a balanced dataset and that common sense is used regarding the conclusions that are drawn from any model run that includes speculative technologies. A careful examination of the technology dataset should be part of any uncertainty analysis.

The model includes a detailed database of energy supply and demand technologies. On the demand side, this database contains energy efficiency options and energy substitution options. For example, to meet the demand for mobility the model might choose between a gasoline-hybrid car, a conventional car with a gasoline-fuelled internal combustion engine, or fuel cell car using hydrogen. The technology choice depends on least-cost criteria that include regional fuel prices, discount rates and technology cost assumptions.

The ETP model structure and data have been characterized in more detail in a number of publications (*e.g.* Gielen and Karbuz, 2003; IEA 2004b).

The fossil fuel supply module

In most sectors the fuel prices constitute a set of key parameters that determine the choice of fuel. The price assumptions from the World Energy Outlook (Table A1.3) have been used to calibrate the ETP model. The figures indicate a coal and gas price gap in 2030 ranging from USD 0.60/GJ in regions with ample gas resources up to USD 3.37/GJ in regions with LNG imports and indigenous coal reserves.

Table A1.3

Coal and gas price projections, (2000-2030)

			2000	2010	2020	2030
Oil		(USD/GJ)	4.95	3.93	4.52	5.12
Gas	USA/CAN/MEX/CSA	(USD/GJ)	3.67	3.58	3.99	4.42
	WEUR/EEUR/AUS	(USD/GJ)	2.88	3.11	3.59	4.06
	FSU/MEAST/AFR/OASIA	(USD/GJ)	1.34	1.15	1.63	2.10
	JAP/SKO/CHI/IND	(USD/GJ)	4.48	3.66	4.13	4.52
Coal	AUS/CHI/USA	(USD/GJ)	1.00	1.05	1.10	1.15
	Others	(USD/GJ)	1.14	1.36	1.44	1.50

Source: IEA 2004a.

A major difference from other bottom-up models is that fuel prices in the ETP model are endogenous. Endogenising fuel prices enables the impact of changes in prices on the demand side to be taken into account.

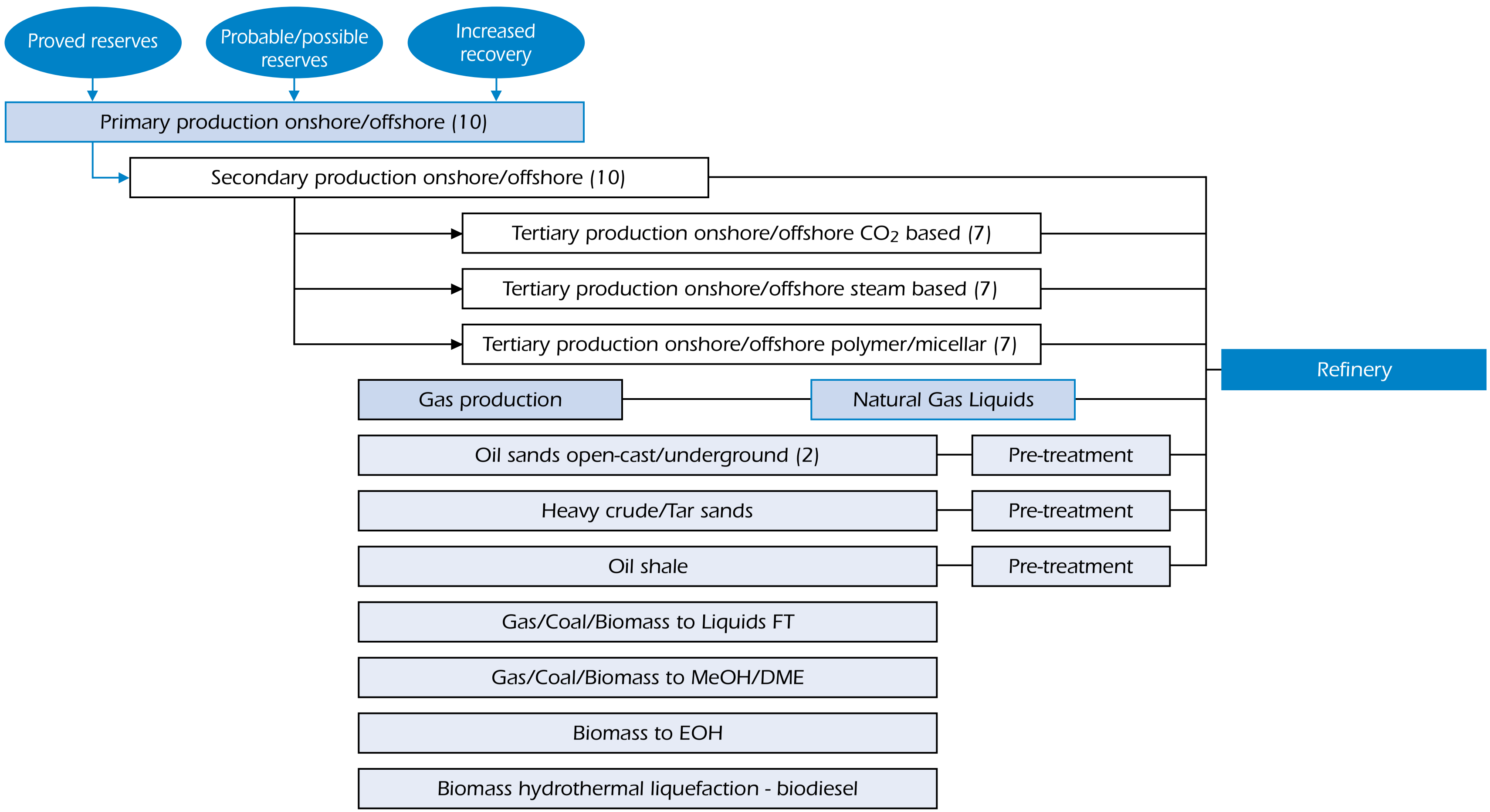
Figure A1.2 shows the oil production and processing module. The modelling of refineries is split into those using light and heavy crude feedstocks. The numbers in the figure refer to the number of technologies that are modelled in a specific category. On the production side, the primary, secondary and tertiary production of oil is modelled as a sequence of processes. CO_2 EOR competes with other methods for enhanced oil recovery. Within the model crude oil competes with synthetic crude oil, while oil products compete with synthetic fuels.

The oil price is calibrated to the World Energy Outlook projections through the supply curve for the producers in the Middle East. The higher their production, the higher the price of oil in the world market.

The data for oil and gas resources in all world regions, except the United States, is taken from the United States Geological Survey (USGS) World Petroleum Assessment 2000 (USGS, 2000) and integrated with IEA data on production of crude oil and natural gas liquids from 1995 to 2000.

Figure A1.2

The ETP oil supply module



Note: Figures in brackets refer to the number of technologies in a specific category. FT = Fischer-Tropsch, MeOH = Methanol and EOH = Ethanol.

The USGS assessment of world oil resources

The USGS study estimates the potential quantities of conventional oil, gas and NGL outside the United States that might be added to reserves in the period 1995-2025. The geologic distribution of petroleum resources is contained in the so-called Total Petroleum System (TPS). Assessment Units (AU), a volume of rock within the TPS that encompasses fields, discovered and undiscovered, sufficiently homogeneous in terms of geology, exploration strategy and risk characteristics to constitute a single population of field characteristics with respect to criteria used for resource assessment, were the basic units for this assessment.

In the USGS assessments, volumetric data of discovered resources are evaluated for each AU as sums of volumes of individual fields, as reported in the databases of Petroconsultants (1996) and NRG Associates (1995).

Tables containing information regarding known and grown volumes of petroleum (*i.e.* conventional oil, NGL and natural gas) in an assessment unit are also provided in the USGS study and publicly available. Grown field sizes are defined as known field sizes adjusted upward using a growth function in each AU.

Oil and gas resources in each world region, except the United States, are equal to the expected total grown volume of existing reserves plus the mean volumes of undiscovered oil, NGL and natural gas.

The USGS volumetric data were then aggregated into the 12 world regions used in the ETP model and converted into their energy equivalents for input into the model. This was done for the median (F50) values of parameters available in the USGS assessment for undiscovered resources and using the relevant factors for conversion (API gravity and sulfur content for oil; inert gas, CO_2 and hydrogen sulfide content for natural gas).

In order to account for the different base years of the USGS study (1995) and the ETP model (2000), the USGS cumulative production figures were updated to the year 2000 using IEA data. The remaining amount of grown oil, NGL and natural gas reserves and undiscovered resources were then re-calculated for the year 2000.

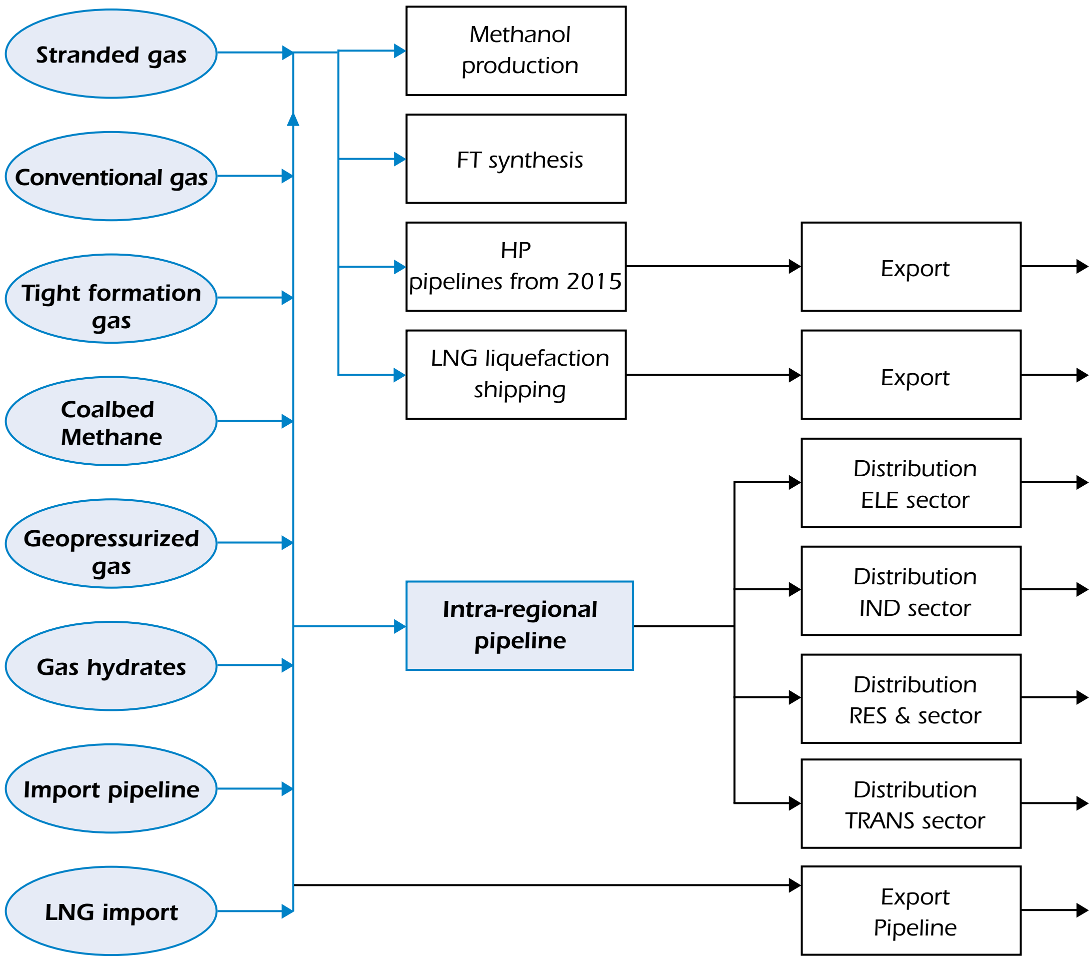
The ETP model includes a number of different conventional and unconventional sources of gas supply (Figure A1.3). Gas transportation pipelines and LNG transportation are modelled in detail, given that transportation costs constitute a large proportion of the delivered price of gas. In the model stranded gas (gas far from markets) can be converted into synfuels or LNG. In the long-term, new types of high-pressure pipelines may allow the transportation of gas to consumer markets from remote areas.

The international coal market is one of the most competitive energy markets, with a wide distribution of resources and a large number of suppliers around the world. Coal reserves are significantly larger than oil and gas reserves, while estimated resource availability is sufficiently high that there is unlikely to be any constraints on supply well beyond the model time horizon.

In all regions brown coal and hard coal are modelled separately (Figure A1.4). For hard coal with a high-ash content raw coal and washed coal are modelled separately. For hard coal with low ash content this difference is not made. The current model does not account for regional differences in the sulphur content and mercury content of coal. In the residential and commercial sectors briquettes are also modelled. Transportation is split into two categories (demand close to the mines and long-distance transportation).

Figure A1.3

The ETP gas supply module



Note: Associated gas is included in conventional gas. HP = High-Pressure. R&C = Residential and Commercial.

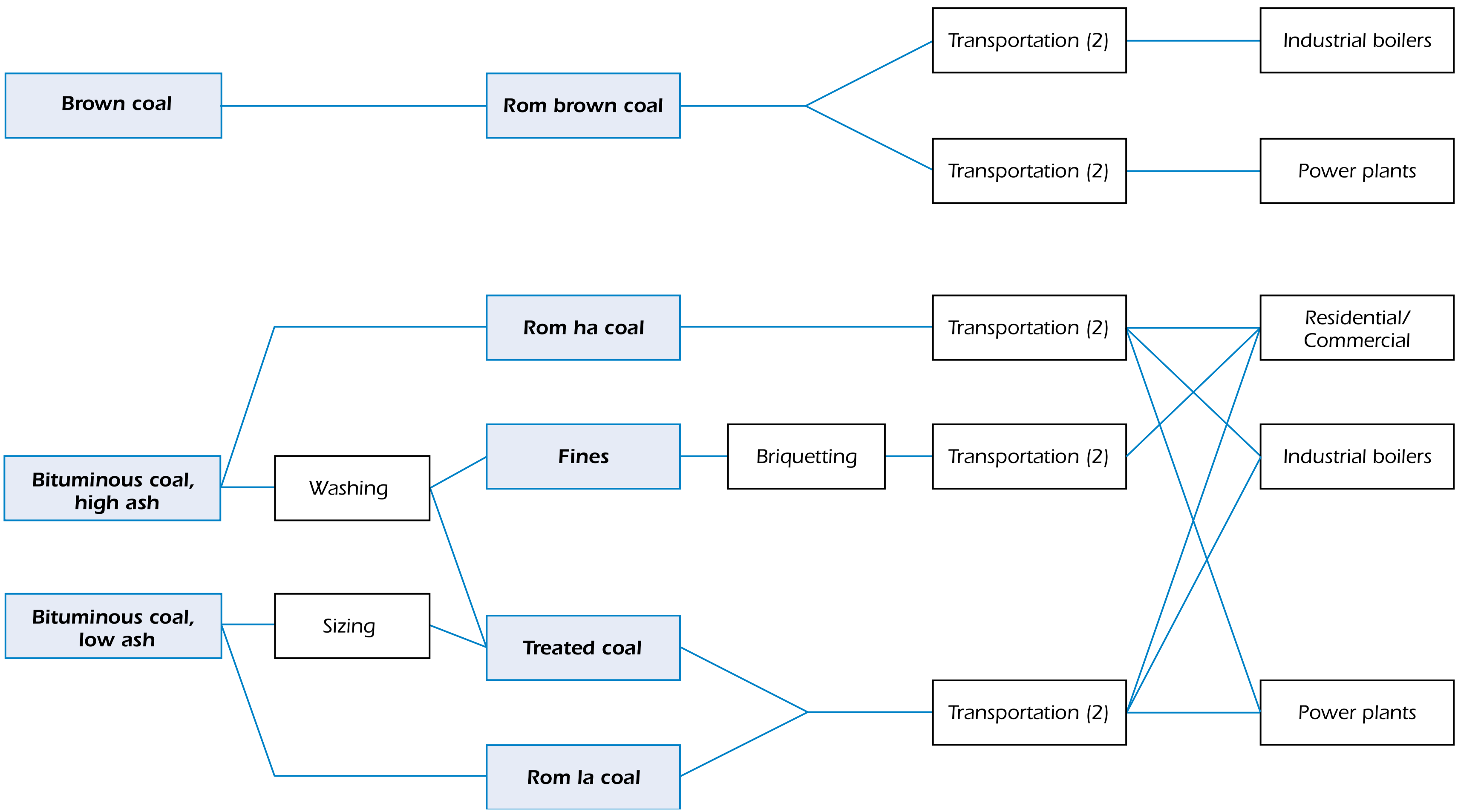
The hydrogen and fuel cell module

The ETP model structure for hydrogen is split into three parts: production, transportation and distribution, and consumption (Figure A1.5).

The "chicken-or-egg" problem is modelled explicitly in the ETP model. The problem is that centralised production, which needs a pipeline distribution system, only makes sense if there is sufficient demand. This threshold problem is modelled through a "hydrogen expansion" variable that forces decentralised production before investments in large-scale centralised can occur. In modelling terms, decentralised units produce a certain amount of this commodity (the "hydrogen expansion" variable) on an annual basis (0.1 units per year) and at the end of their life span (1 unit). Each unit of the expansion variable produced in turn "enables" investments into one unit of centralised hydrogen production.

Figure A1.4

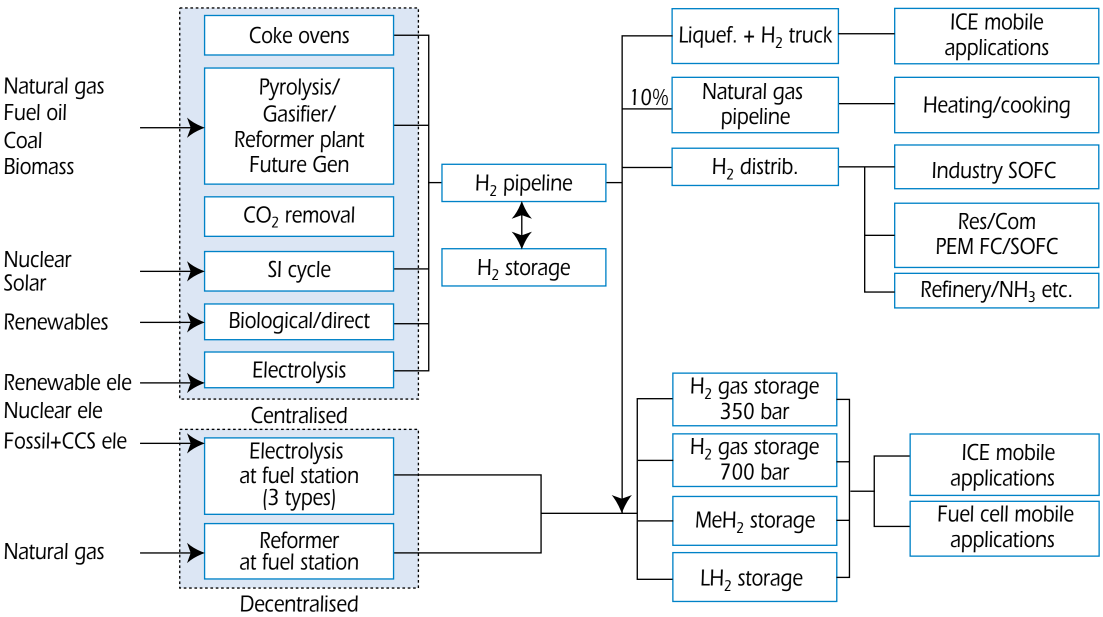
The coal supply module in the ETP model



Note: Rom = Run of mine, ha = high ash, and la = low ash. Transportation is split into two categories: demand close to the mines and long-distance transportation.

Figure A1.5

The ETP hydrogen supply and demand module



Note: SI cycle = Sulfur/Iodine cycle, ICE = Internal Combustion Engine, PEM FC = Proton Exchange Membrane Fuel Cell and SOFC = Solid Oxide Fuel Cell.

Fuel cells have been considered as a technology option for vehicles, for CHP in the residential, commercial and industrial sectors and for centralised electricity production. Fuel cells in the residential and commercial sectors cogenerate electricity, heat and hot water in the ratio of 1:1:0.5. They can be fired with hydrogen, natural gas or heating oil. The electric efficiency is 36% for each of the three fuels (full system average over the year, DC electricity). This gives a total systems efficiency of 90%. In low-rise dwellings the model uses 1 kW SOFC systems, while for apartment buildings a 100 kW MCFC/SOFC system is modelled (MCFC systems can only use syngas or natural gas, as they need CO_2). These 100kW systems have been restricted to the OECD regions and transition economies, and generate electricity, heat and hot water in a ratio 1:0.45:0.3. The electric efficiency is 56%, while the overall system efficiency is 97%.

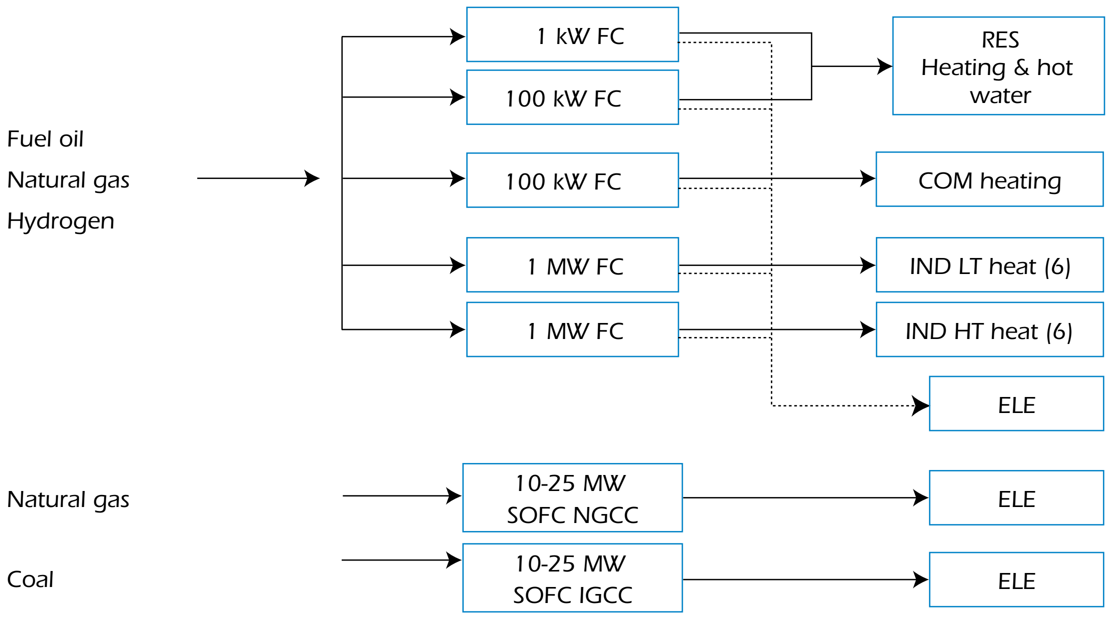
Commercial sector buildings are assumed to use a 100 kW fuel cell that generates electricity and heat in a ratio of 1:1. The electric efficiency is 45% and the total system efficiency is 90%.

In industry, large-scale CHP systems (>100 kW) have been modelled that cogenerate electricity and heat. Both low temperature (<200 °C) and high temperature (<200 °C) heat cogeneration systems have been considered. The electricity-to-heat ratio is sector specific and ranges from 1:1.4 to 1:2. The fuel cells can be fired with natural gas, fuel oil or hydrogen. Fuel cells have been considered for the following industry sectors: non-ferrous metals, ferrous metals, chemicals, machinery, food and tobacco, textile and leather, and paper and pulp industries.

In centralised power production, SOFC integration into natural gas and coal-fired combined cycles has been considered, with and without CCS. These systems achieve high electric efficiencies: 56% for the coal-fired systems and 66% for the gas-fired systems.

Figure A1.6

Modelling of fuel cells in the ETP model



The biofuels module

Biofuels are the main competitor for hydrogen in the transportation sector. Therefore, the data for these fuels play an important role in the analysis of hydrogen. Both biomass supply assumptions and biofuels production processes will be discussed.

The primary biomass supply is split into 12 supply categories, listed in Table A1.4

Table A1.4

Primary biomass supply options in the ETP model

MINBIOBAG1	Bagasse production (sugar by-product only)
MINBIOBIN0	Production of industrial wastes
MINBIOBMU0	Production of municipal wastes (biomass content only)
MINBIOBSB0	Production of solid biomass for biofuel (existing)
MINBIOBSL0	Production of fuelwood (existing)
MINBIOBSL2	Production of wastes & residues (additional)
MINBIOBSL4	Production of straw and other agricultural residues
MINBIOBSL5	Additional recovery potential from forests
MINBIOBSL6	New supply of solid biomass – plantations on arable land
MINBIOBSL7	New supply of solid biomass – plantations on permanent pasture land
MINBIOCAN1	Production of sugarcane for ethanol
MINBIOCEL1	Production of cellulosic and starch biomass for ethanol

On top of these supply options, there is black liquor production from chemical pulping, which is endogenous to the model.

The total supply potential in 2050 is shown in Table A1.5. It adds up to more than 200 EJ. This should be compared to a current primary energy use of over 400 EJ per year, and biomass use of 40 EJ per year.

Table A1.5

Global biomass supply potentials, 2050

	Primary biomass potential 2050 (EJ/yr)	Production cost (USD/GJ)
Existing wood fuel	24.6	0.5
Forest residues	27.7	5
Industrial wastes	3.2	1
Industrial wastes (additional)	3.2	2
Agricultural residues	43.7	4
Plantations (arable)	16.3	2
Plantations (marginal land)	33.8	4
MSW biomass	1.8	2
Existing biofuels	0.8	0
Bagasse by-product from sugar	7.5	0.1
New cane	15.6	8-15 USD/t cane
Other cellulosic crops	10.2	2-5
Black liquor	12.1	0
Total	200.5	

The results are based on the following assumptions:

- Wood fuel from FAO statistics in 2002 (FAO, 2004). Cubic metres translated into GJ assuming 600 kg dry matter/m^3 and 18 GJ/t.
- Forest residues estimated based on current forest area, an assumed re-growth and current recovery from FAO statistics (FAO, 2004).
- Industrial wastes: 25% of sawlogs, other veneer logs and other industrial roundwood production from FAO statistics (FAO, 2004).
- Agricultural wastes: arable land, 5 t residues/ha and a region-specific percentage of residues, ranging from 25% to 75%, that is needed for other applications such as land cover, soil fertilisation and biofuels.
- Plantations on arable land and marginal lands: 5% of all arable land in all regions can be used for bioenergy plantations by 2050. The average annual yield ranges from 135 to 270 GJ/ha (7.5-15 t of dry matter [odm] biomass/ha per year). Also 10% of all permanent pasture land can be used for bioenergy plantations/afforestations (it is assumed that degraded land falls largely in this category). The yields range from 45-135 GJ/ha. per year (2.5 to 7.5 t odm biomass/ha per year).
- Biomass in MSW: taken from IEA statistics, assuming a doubling till 2050 (this should be considered a low estimate).
- Existing biofuels (mainly Brazilian sugarcane ethanol and US corn ethanol): taken from IEA energy statistics, multiplied by 2 to calculate primary energy needs.

- New cane: estimated a potential doubling of global production between 2000-2050, based on production trends 1960-2005 according to FAO statistics. This additional production would represent about 30 million ha, or about 2% of global arable land.
- Other cellulosic crops: 5% of arable land, yields ranging from 5 to 10 t/ha per year.
- Black liquor: The 2050 potential represents a 4-5 fold increase of 2000 potentials. This assumes a strong growth in paper production, and a continued shift from mechanical pulp to chemical pulp. This should be considered a high estimate.

In total, 12% of global arable land would be available for bioenergy production by 2050, 10% of all pasture land, as well as maximizing the recovery of residues from forests and from agriculture for bioenergy. If the full potential were used, one-third of the biomass would come from existing forests, one-third from by-products and one-third from dedicated plantations.

In 2003, world fuel ethanol production amounted to 28 billion litres. At 21.1 MJ/l (LHV), that equals 0.4 mb/d (about 0.5% of global oil consumption). The production is mainly concentrated in Brazil and the United States. This production is based on sugar cane in Brazil and on corn in the United States. Data for ethanol production cost from cane and starch crops such as corn were taken from the FO Lichts newsletters (FO Lichts 2004, 2005a, 2005b). Various countries and regions are planning a rapid expansion of ethanol production. Some scenarios suggest that a ten-fold increase (to 4 mbd) by 2020 would be feasible, based on sugar cane ethanol alone (IEA 2004c). The resource base for ethanol production is gradually widening to cellulosic crops, and even wood. Such low-cost feedstocks would result in an increase in the global production potential for low-cost ethanol.

Also, biomass can be converted via FT-processes. Costs are higher than for gas and coal, because of the unfavourable economies of scale related to the dispersed nature of the biomass resource. Production costs are around USD 90/bbl (USD 19/GJ) for a biomass feedstock price of USD 3/GJ (Hamelinck *et al.*, 2004). These costs could be reduced to USD 70-80 /bbl (USD 14-16/GJ). Due to its high cost this process is not currently in use. However, model analysis suggests that this may change if CO_2 incentives are introduced. A combination of FT-synthesis with CO_2 capture and storage could become attractive, provided sufficient economic of scale can be achieved. Such a production process would result in net CO_2 removal from the atmosphere.

One of the more exotic options for CO_2 capture is the production of hydrogen and other synfuels from biomass (Read and Lermit 2003). This strategy reduces atmospheric CO_2 concentrations and produces energy at the same time. The scale of biomass hydrogen production plants are typically one order of magnitude smaller than coal-based hydrogen production plants. Given that investment costs of chemical plants typically increase with scale by a factor of 0.7, the specific investment costs for biomass-based hydrogen production is twice that of coal-based hydrogen production per unit of energy.

Many other biofuels production technologies are under development, such as flash pyrolysis and hydrothermal liquefaction. HTU is an acronym for HydroThermal Upgrading. Biomass (wet chips or a slurry) is treated with water in a mixed reactor at temperatures of 300-350 °C at pressures of 120 to 180 bar for 5-10 minutes. This type of conversion process is called hydrothermal liquefaction. The oxygen content of the biomass is reduced from 40 weight% to about 10-15% by the selective formation of CO_2. Under these conditions, an organic liquid (or "biocrude") is formed, which resembles crude oil. The biocrude can be upgraded to a naphtha-like product by removal of the remaining oxygen (by catalytic hydro-deoxygenation, using hydrogen). The upgraded product can be used as a feedstock in the production of chemicals based on the existing steamcracking technology (Naber et al 1999). The HTU process can take different feedstocks and could be an attractive option for feedstocks with a high water content such as kitchen waste, or waste water treatment sludge, since no drying is required.

Previous attempts in the United States in the 1970s and 1980s to develop a similar process failed because of problems with the biomass injection system and due to insufficient understanding of the reaction mechanisms and the process dynamics. The HTU process and its predecessors are based on the use of water as a solvent. Other organic solvents may be more promising options (solvolysis), because they can reach similar temperatures in a liquid state at atmospheric pressures, resulting in significantly reduced process equipment costs (Venderbosch *et al.*, 2000). More research is required before this process can become operational. Following successful pilot plant tests in recent years, the Dutch government has recently announced its support for a demonstration plant.

Figure A1.7

The bioenergy supply and demand module in the ETP model

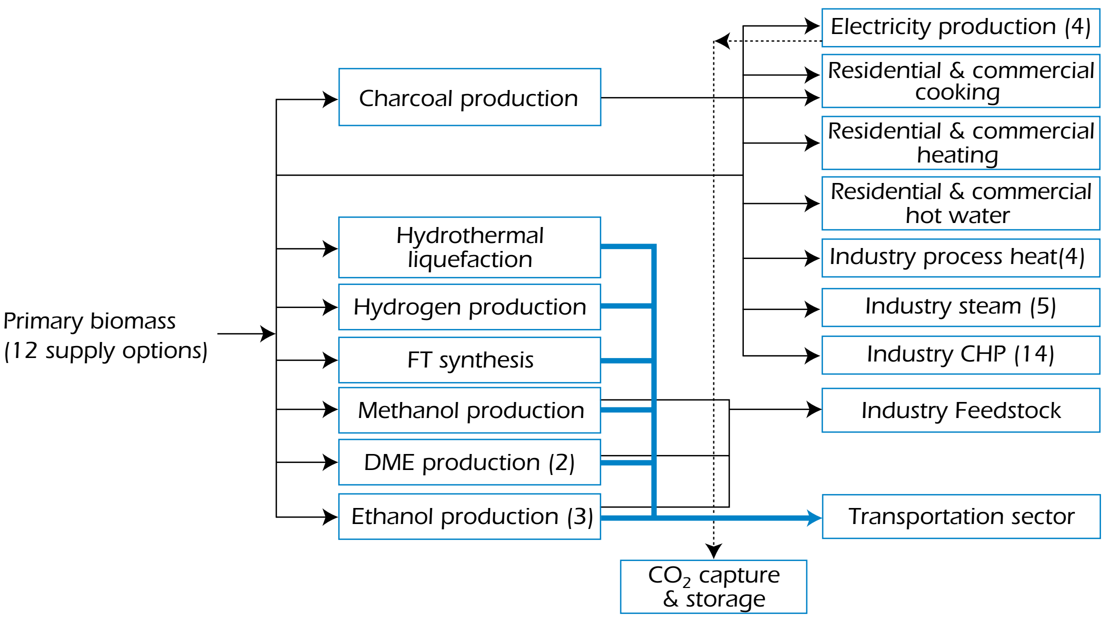


Table A1.6

Biomass supply potential by region, 2050

(PJ/yr)	AFR	AUS	CAN	CHI	CSA	EEU	FSU	IND	JPN	MEA	MEX	ODA	SKO	USA	WEU	
MINBIOBAG1	434	115	0	623	3 166	0	0	1 449	6	0	236	1 310	0	155	0	7 494
MINBIOBIN0	150	83	452	234	257	123	252	50	31	26	17	502	2	658	400	3 237
MINBIOBMU0	20	20	20	20	20	20	20	20	87	0	40	20	11	910	580	1 808
MINBIOBSB0	0	0	0	0	569	0	0	0	0	0	0	0	0	240	25	835
MINBIOBSL0	5 737	33	33	2 063	2 909	170	644	3 246	1	77	410	8 414	27	465	358	24 586
MINBIOBSL2	151	83	452	234	257	123	252	50	31	26	17	502	2	658	400	3 237
MINBIOBSL4	3 500	1 900	1 700	2 700	8 300	1 600	7 600	3 000	200	1 200	500	2 000	100	6 600	2 800	43 700
MINBIOBSL5	4 236	242	2 432	194	10 368	106	5 779	3	451	4	484	24	118	2 561	702	27 704
MINBIOBSL6	2 496	672	309	1 925	1 999	387	1 364	2 183	60	880	335	1 407	23	1 584	679	16 303
MINBIOBSL7	8 104	1 855	131	5 400	8 309	176	1 620	149	6	2 592	720	2 090	1	2 104	534	33 791
MINBIOCAN1	4 000	400	0	1 600	4 000	0	0	1 600	0	0	0	4 000	0	0	0	15 600
MINBIOCEL1	1 479	299	274	1 141	1 185	258	808	1 294	35	391	198	834	13	1 408	603	10 221
Black liquor	108	1 632	814	4 400	340	245	140	480	525	25	95	435	270	1 265	835	11 609
	30 414	7 334	6 617	20 534	41 679	3 208	18 479	13 524	1 433	5 221	3 052	21 538	566	18 607	7 917	200 124

The transport module

The transport sector is divided into 15 demand categories:

- Domestic aviation.
- International aviation.
- Buses.
- Minibuses.
- Three wheels.
- Heavy trucks.
- SUVs and light trucks.
- Light and medium commercial trucks.
- Cars.
- Two wheels.
- Taxis.
- Rail-freight.
- Rail-passenger.
- Domestic ships.
- International ships.

The demand projections and the reference efficiency trends are taken from the Sustainable Mobility study. This study was jointly developed by the IEA and the World Business Council on Sustainable Development (WBCSD, 2004). Efficiency options have been considered for regular ICEs (up to a 20% efficiency gain, compared to the autonomous efficiency gain). Hybrid vehicles have been considered and can result in even more substantial efficiency gains.

Apart from efficiency measures, a number of fuel alternatives are considered for passenger cars:

- Gasoline.
- Diesel.
- DME.
- Pure ethanol (for flex vehicles).
- 10% ethanol in gasoline.
- Compressed Natural Gas (CNG).
- Hydrogen.
- LPG.
- Methanol.

In certain cases (*e.g.* in the case of hydrogen), the use of alternative fuels results in efficiency gains. Diesel and gasoline can be produced from crude oil in refineries, or they can be produced from coal, natural gas and biomass. If there is demand for such oil products in other sectors, it is not possible to allocate the synthetic production of these fuels directly to the transportation sector. A weighted allocation has been used as a proxy in the analysis.

Annex 2.

REGIONAL INVESTMENT COSTS, DISCOUNT RATES AND FUEL TAXES

Regional investment costs

The ETP model covers 15 regions. The database is set up as one "reference dataset" with cost data for the United States. Costs in other regions are calculated by multiplying United States cost data by a region-specific factor. These region-specific cost multipliers are listed in Table A2.1.[24] These multipliers are applied to all processes.

This detailed, but still rather crude, representation of the world energy system poses certain limitations:

- Currency exchange rates tend to fluctuate, affecting the economics of different options. Changing exchange rates affect the relative investment costs. In particular, exchange rates for developing countries can fluctuate by a factor of two.
- The project system boundaries may differ by region and by site. For example, in developing countries it may be necessary to build roads, new power lines or other infrastructure for new power plants.
- The regions in the model are very large. The cost factor is an average that may differ considerably for different countries within a region, and even by location within a country.
- Particularly in developing countries, some technologies require imported equipment, while others are based on locally produced equipment. Such a difference can impact investment costs significantly, and also bring the currency exchange factor into play.
- In developing countries the availability of skilled labour may be a limiting factor. If workers have to be hired from abroad, this will affect labour cost. Operating and maintenance costs consist of 50% labour costs (that are region specific) and 50% materials and auxiliaries costs (that are assumed to be the same in all regions).

Table A2.1

Region specific cost multipliers

	Investment cost	Fixed O&M	Variable O&M
AFR	125	90	85
AUS	125	90	90
CAN	100	100	100
CHI	90	80	80
CSA	125	90	85
EEU	100	90	85
FSU	125	90	85
IND	90	80	80
JPN	140	100	100
MEA	125	90	85
MEX	100	90	90
ODA	125	80	80
SKO	100	90	90
USA	100	100	100
WEU	110	100	95

Note: USA = 100.

24. These multipliers do not apply to energy and materials inputs that are modelled as physical flows. The regional price of these flows is calculated by the model.

Discount rates: liberalisation, risk and time preferences

The discount rates used in the model for investment decisions differ by region and by sector (Table A2.2). The discount rates used should ideally reflect real world discount rates. These discount rates are usually significantly higher than the long-term social discount rate. Economists' opinions differ as to which discount rates should be applied for CO_2 policy analysis (Portney and Weyant, 1999).

ETP model discount rates are real discount rates, *i.e.* they exclude inflation. The discount rate will differ among world regions, depending on capital availability and perceived risk.

The money supply available for investment can be divided into loans and own capital and equity. The long-term return on investment for equity is several percent higher than for loans, because the owner of the equity is exposed to an increased risk (that the company goes bankrupt, in which case loans are paid back first, and usually the equity owner gets nothing). In a situation where the electricity supply system is owned by the government, the lending rate may apply, due to the lower perceived risk. In liberalised energy markets, the equity rate is more plausible.

The ETP figures are based on the 30-year government bond rate (for the main country in the region, if applicable), corrected for inflation. For developing countries, Moody's country rankings have been used as a measure of a countries sovereign credit risk. Industry financing has been split into lending and equity (stocks, etc.). One percentage point is added to the bond rate in the case of borrowing by companies in order to reflect the average incremental risk associated with lending to companies, whereas 5.5 percentage points are added to the bond rate for industrial equity risk.

Table A2.2

Discount rates by region and sector in the ETP model

	Real bond yield 2000-2001 (% pa)	Industry and electricity sectors Lending (% pa)	Equity (% pa)	Transport Sensitivity analysis (% pa)	Res/Services Sensitivity analysis (% pa)
AFR	8.2	9.2	13.7	18.2	28.2
AUS	2.6	3.6	8.1	12.6	12.6
CAN	3.7	4.7	9.3	13.7	13.7
CHI	5.2	6.2	10.7	15.2	25.2
CSA	7.2	8.2	12.7	17.2	27.2
EEU	5.7	6.7	11.3	15.7	15.7
FSU	8.7	9.7	14.3	18.7	18.7
IND	8.0	9.0	13.5	18.0	28.0
JPN	2.0	3.0	7.5	12.0	12.0
MEA	5.6	6.6	11.1	15.6	25.6
MEX	7.2	8.2	12.7	17.2	18.2
ODA	8.2	9.2	13.7	18.2	18.2
SKO	5.6	6.6	11.1	15.6	15.6
USA	4.2	5.2	9.7	14.2	14.2
WEU	3.7	4.7	9.3	13.7	13.7

In the reference model runs, the regional discount rate for each of the transport, residential, services, industry and electricity generation sectors is set at the equity rate for the industrial and electricity sectors. However, in a number of other model runs, higher discount rates have been applied to the transport sector and the residential/services sector, as detailed in Table A2.2.

In many countries transportation markets are subject to major government intervention through regimes that favour or tax certain types of fuel. This includes value added taxes (VAT), excise tax, and taxes on certain drive systems (*e.g.* diesel engines) or progressive taxes on engine volumes. For example gasoline taxes (excise tax plus VAT) range from USD 3/GJ in the United States to USD 29/GJ in the United Kingdom, a difference of one order of magnitude (Table A3.2). The United Kingdom tax level represents a three-fold increase in gasoline supply cost. In many countries the tax on diesel fuel is lower than on gasoline, thus favouring the use of diesel. Also ethanol and natural gas are often exempt from fuel taxes, or subject to preferential tax regimes in many countries. Such tax exemptions can provide a strong incentive to use such alternative fuels. However, there should be a basis for such exceptions to tax systems, as tax revenues are needed to pay for the transport infrastructure. In the case of transport fuels, they should reflect the positive externalities of alternative fuels, such as enhanced energy-security or reduced environmental effects.

Table A2.3

Transportation fuel taxes for non-commercial use, 2003

	Diesel (USD/GJ)	Gasoline (USD/GJ)
OECD countries		
Australia	8.6	8.6
Austria	13.3	18.0
Belgium	13.7	26.9
Canada	1.5	6.1
Czech Republic	12.3	15.5
Denmark	17.8	24.7
Finland	15.0	27.6
France	16.8	26.0
Germany	19.1	25.9
Greece	11.0	12.9
Hungary	16.2	18.9
Ireland	15.2	20.4
Italy	17.7	18.3
Japan	8.5	17.2
Korea	12.0	16.7
Luxembourg	10.9	9.2
Mexico	5.8	0.3
Netherlands	15.2	11.9
New Zealand	1.2	9.3
Norway	20.0	29.6
Poland	11.1	18.0
Portugal	13.0	23.8
Slovak Republic	14.1	18.0
Spain	12.6	0.0
Sweden	17.0	26.7
Switzerland	18.3	17.8
Turkey	17.3	0.0
United Kingdom	27.0	28.7
United States	3.4	2.9
Non-OECD countries		
India	3.5	6.9
China	0.0	0.0
Russia	1.8	2.6
South Africa	4.5	4.5

Source: IEA, 2004c.

For the model analysis it is assumed that the regional taxes remain at their current levels in absolute terms (USD/GJ) through the period 2000-2050. The diesel tax in Europe is set at 75% of the gasoline tax. For alternative fuels (CNG, LPG, DME, ethanol, methanol) it is assumed that a tax is gradually introduced and reaches 75% of the gasoline tax by 2050. Synthetic gasoline and diesel (FT fuels) are assumed to be taxed like gasoline and diesel from oil, as it will be very difficult to justify a difference. This approach of gradually increasing taxes ensures that government revenue streams are not compromised as the use of alternative fuels grow.

Annex 3.

BENEFIT/COST RATIOS OF HYDROGEN TECHNOLOGIES AND FUEL CELLS

If a technology is not cost-effective, it will not show up in the ETP model solution. Some of these technologies may be close to competitiveness, while others may be far away from competitiveness. In fact, a technology that is close to competitiveness may gain a certain market share, and its development may make sense, given the uncertainty in the future technology data projections. One way to identify such technologies by looking at the benefit-cost ratio (B/C ratio). The benefits represent the value of the technology outputs (the quantity multiplied by the shadow price). The cost is the value of the technology inputs (quantity multiplied by the shadow price, plus annualized capital cost, plus other cost components, *e.g.* emission duties). The B/C is 1 for a "marginal technology", *i.e.* the technology with the highest cost that is selected by the model algorithm to produce a certain commodity. The B/C ratio in the model is dynamic; if the B/C is larger than 1, the model would like to invest more in this technology, but there is a constraint that prevents additional investments. A B/C ratio of more than 1 is an indication of a very attractive technology. A B/C ratio of less than 1 indicates a technology that is not cost-effective. However, if its value is above 0.9, this indicates a technology that may warrant more attention. The Tables A6.1 to A6.3 show the B/C ratios for all hydrogen and fuel cell technologies in the MAP scenario.

Table A3.1

The B/C ratios of hydrogen supply technologies for the USA in the MAP scenario

Process	Range 2030-2050
EHTGRH25 (EPLT: .G1.00.CON.NUC.CEN. (Hydrogen production from nuclear heat SI cycle)	0.78
ESOTHH2100 (EPLT: .G1.00.CON.SOL.CEN. (Hydrogen production from solar heat SI cycle)	0.44-0.70
EZIGC1130 (IGCC +CO_2 removal "FutureGen" coal to electricity and hydrogen)	1.00
HBIO115 (Hydrogen from Biomass gasification)	0.30-0.44
HBIO130 (Hydrogen from Biomass Photo-Biological)	0.41-0.55
HELE105 (Hydrogen Advanced electrolyser/inorganic membrane 1-30 bar)	0.54-0.91
HELE106 (Hydrogen High temperature electrolysis 1-30 bar)	0.50-0.78
HELE107 (Hydrogen High pressure electrolysis 800 bar)	0.45-0.74
HHCO105 (Hydrogen from hardcoal centralised)	0.45-0.74
HNGA105 (Hydrogen from natural gas centralised)	0.50-0.95
HNGAD105 (Hydrogen from natural gas decentralised)	0.55-0.70
HZBIO125 (Hydrogen from biomass + CO_2 removal)	0.75-0.80
HZHCO105 (Hydrogen from hardcoal + CO_2 removal)	0.66-1.00
HZNGA105 (Hydrogen from natural gas + CO_2 removal)	0.49-0.62

Table A3.2

The B/C ratios of hydrogen technologies in the transport sector for the USA in the MAP scenario

Process	Range 2030-2050
TADHYD020 (Domestic aircraft hydrogen fueled 10 km alt)	0.97-1.00
TAIHYD030 (International aircraft hydrogen fueled 10 km alt)	0.93-0.98
TRAHH1000 (Fuel Tech - Gaseous Hydrogen 400/350 BAR (TRA))	1.00
TRAHH2000 (Fuel Tech - Gaseous Hydrogen 800/700 BAR (TRA))	1.00
TRAHL1000 (Fuel Tech - Liquid Hydrogen (TRA) for airplanes no tax)	0.67-0.76
TRAHL2000 (Fuel Tech - Liquid Hydrogen (TRA) for road vehicles)	1.00
TRBFCH000 (BUS: Hydrogen fuel cell)	0.94-0.95
TRBHYH000 (BUS: Hydrogen hybrid)	0.94-0.96
TRLHHF020 (SUV+LCV: Hydrogen FCV MeH_2 STORAGE)	0.93-0.95
TRLHHG005 (SUV+LCV: Hydrogen FCV Gaseous storage)	0.92-0.95
TRLHLC005 (SUV+LCV: Hydrogen ICE Liquid H_2 storage)	0.91-0.94
TRLHYH015 (SUV+LCV: Hydrogen HEV)	0.91-0.95
TRMHHG000 (COMM LIGHT/MEDIUM TRUCK: Hydrogen FCV gaseous storage)	1.00
TRMHYH000 (COMM LIGHT/MEDIUM TRUCK: Hydrogen HEV)	0.94-1.00
TRTHHF020 (CAR: Hydrogen FCV MeH2 storage)	0.97-0.99
TRTHHG000 (CAR: Hydrogen FCV Gaseous storage)	1.00
TRTHLC005 (CAR: Hydrogen ICE Liquid storage)	0.96-1.00
TRTHYH015 (CAR: Hydrogen HEV)	0.82-1.00
TWIDST020 (International shipping diesel/fuel oil MCFC fuel cell)	0.97-1.00

Table A3.3

The B/C ratios of stationary fuel cells for the USA in the MAP scenario

Process	Range 2030-2050
ECOMHFOFC3 (Commercial CHP, fuel oil, SOFC 100 kW, Highrise)	0.43-0.61
ECOMHYDFC3 (Commercial CHP, hydrogen, SOFC 100 kW, Highrise)	0.46-0.67
ECOMNGAFC3 (Commercial CHP, natural gas, SOFC 100 kW, Highrise)	0.51-0.67
EINDPBFC1 (Non-Ferrous high-temperature CHP, fuel oil, SOFC 1 MW)	0.43-1.00
EINDPBFC2 (Non-Ferrous high-temperature CHP, hydrogen, SOFC 1 MW)	0.57-0.70
EINDPBFC3 (Non-Ferrous high-temperature CHP, natural gas, SOFC 1 MW)	0.68-0.79
EINDPCFC1 (Chemicals high-temperature CHP, fuel oil, SOFC 1 MW)	0.43-0.46
EINDPCFC2 (Chemicals high-temperature CHP, hydrogen, SOFC 1 MW)	0.40-0.48
EINDPCFC3 (Chemicals high-temperature CHP, natural gas, SOFC 1 MW)	0.68-0.95
EINDPMFC1 (Machinery high-temperature CHP, fuel oil, SOFC 1 MW)	0.50-1.00
EINDPMFC2 (Machinery high-temperature CHP, hydrogen, SOFC 1 MW)	0.56-0.74
EINDPMFC3 (Machinery high-temperature CHP, natural gas, SOFC 1 MW)	0.71-0.95
EINDPSFC1 (Iron&Steel high-temperature CHP, fuel oil, SOFC 1 MW)	0.51-0.94
EINDPSFC2 (Iron&Steel high-temperature CHP, hydrogen, SOFC 1 MW)	0.55-0.76
EINDPSFC3 (Iron&Steel high-temperature CHP, natural gas, SOFC 1 MW)	0.78-0.91
EINDSBFC1 (Non-Ferrous low temperature CHP, fuel oil, SOFC/MCFC 1 MW)	0.49-0.71
EINDSBFC2 (Non-Ferrous low temperature CHP, hydrogen, SOFC/MCFC 1 MW)	0.50-0.74

Table A3.3 (continued)

The B/C ratios of stationary fuel cells for the USA in the MAP scenario

Process	Range 2030-2050
EINDSBFC3 (Non-Ferrous low temperature CHP, natural gas, SOFC/MCFC 1 MW)	0.64-0.79
EINDSCFC1 (Chemicals low temperature CHP, fuel oil, SOFC/MCFC 1 MW)	0.55-0.66
EINDSCFC2 (Chemicals low temperature CHP, hydrogen, SOFC/MCFC 1 MW)	0.49-0.69
EINDSCFC3 (Chemicals low temperature CHP, natural gas, SOFC/MCFC 1 MW)	0.61-0.75
EINDSFFC1 (Food&Tobacco low temperature CHP, fuel oil, SOFC/MCFC 1 MW)	0.55-0.77
EINDSFFC2 (Food&Tobacco low temperature CHP, hydrogen, SOFC/MCFC 1 MW)	0.50-0.82
EINDSFFC3 (Food&Tobacco low temperature CHP, natural gas, SOFC/MCFC 1 MW)	0.66-0.84
EINDSLFC1 (Textile&Leather low temperature CHP, fuel oil, SOFC/MCFC 1 MW)	0.48-0.66
EINDSLFC2 (Textile&Leather low temperature CHP, hydrogen, SOFC/MCFC 1 MW)	0.48-0.72
EINDSLFC3 (Textile&Leather low temperature CHP, natural gas, SOFC/MCFC 1 MW)	0.62-0.81
EINDSMFC1 (Machinery low temperature CHP, fuel oil, SOFC/MCFC 1 MW)	0.60-0.69
EINDSMFC2 (Machinery low temperature CHP, hydrogen, SOFC/MCFC 1 MW)	0.49-0.72
EINDSMFC3 (Machinery low temperature CHP, natural gas, SOFC/MCFC 1 MW)	0.64-0.85
EINDSPFC1 (Paper&Pulp low temperature CHP, fuel oil, SOFC/MCFC 1 MW)	0.54-0.72
EINDSPFC2 (Paper&Pulp low temperature CHP, hydrogen, SOFC/MCFC 1 MW)	0.50-0.79
EINDSPFC3 (Paper&Pulp low temperature CHP, natural gas, SOFC/MCFC 1 MW)	0.66-0.84
ERESHFOFC1 (Residential CHP, fuel oil, SOFC 1 kW, Lowrise)	0.55-0.74
ERESHFOFC2 (Residential CHP, fuel oil, SOFC 1 kW, Highrise)	0.60-0.75
ERESHFOFC3 (Residential CHP, fuel oil, SOFC 100 kW, Highrise)	0.67-0.83
ERESHYDFC1 (Residential CHP, hydrogen, SOFC 1 kW, Lowrise)	0.43-0.65
ERESHYDFC2 (Residential CHP, hydrogen, SOFC 1 kW, Highrise)	0.48-0.55
ERESHYDFC3 (Residential CHP, hydrogen, SOFC 100 kW, Highrise)	0.46-0.53
ERESNGAFC1 (Residential CHP, natural gas, SOFC 1 kW, Lowrise)	0.50-0.65
ERESNGAFC2 (Residential CHP, natural gas, SOFC 1 kW, Highrise)	0.77-0.96
ERESNGAFC3 (Residential CHP, natural gas, SOFC 100 kW, Highrise)	0.64-0.82
ESOFCOAC25 (Centralized power plant SOFC (COAL) >20MW)	0.66-0.78
ESOFGASC20 (Centralized power plant SOFC (GAS) >20MW)	0.86-0.99
EZSOFCOA35 (Centralized power plant SOFC (COAL) + CO_2 removal - 2035)	0.32-0.57
EZSOFGAS30 (Centralized power plant SOFC (GAS) + CO_2 removal - 2030)	0.44-0.91

Annex 4.
THE GREENHOUSE EFFECTS OF HYDROGEN AIPLANES

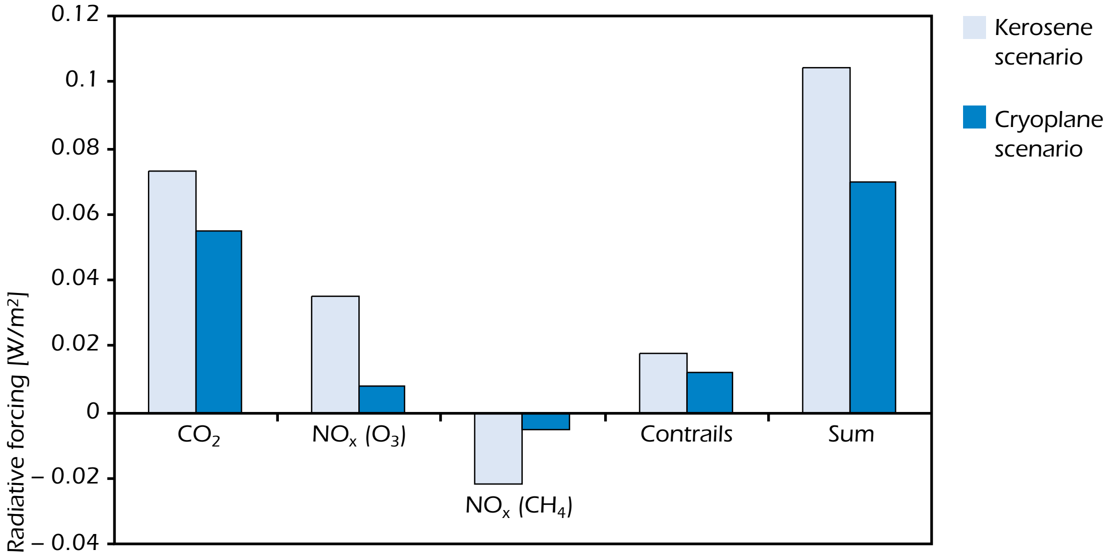
The use of hydrogen does not contribute to climate change for all stationary and most mobile applications. However, in the stratosphere (at the cruising altitude of air planes), H_2 will contribute to climate change. Three mechanisms are at work, only one of which is an environmental benefit. First the contrails from a hydrogen fuelled airplane may be different than the contrails of a kerosene fuelled airplane. There would be more contrail from H_2 aircraft due to the increased water vapor emitted, and they will persist under more varied atmospheric conditions, compared to kerosene contrails. This could enhance heat trapping in the atmosphere. However the impact could be offset by the change in the physical properties of the contrails produced (an H_2 engine would produce a contrail with larger but fewer ice particles). In the EU cryoplane project, it is estimated that global average climate impact for H_2 contrails would be the same or slightly lower than for conventional aircraft. However, this estimate needs to be verified by field tests.

Second, flying in the stratosphere with H_2 would result in more water vapor in the stratosphere which then does not precipitate out quickly (*i.e.* it gets stuck up there), so H_2 would probably be worse for climate change due to the accumulation of water vapor. The relevance of the H_2O emission is height dependent. Below 10 km it is irrelevant, but at higher altitudes it is significant.

Third, NO_x emissions are a precursor to particulates, and such stratospheric particulates result in global warming. Neglecting NO_x will under-estimate the GHG benefits of a switch to hydrogen by a factor of 2 at a cruising altitude of 11 km.

Figure A4.1

Radiative forcing in 2050 with kerosene jet engines or a gradual transition over 2000-2050 to hydrogen-fuelled airplanes



Source: Airbus, 2003, p. 58

Figure A4.1 shows the radiative forcing in 2050 without any hydrogen airplanes and with a gradual transition to hydrogen airplanes only by 2050. Due to the life span of CO_2 in the stratosphere, CO_2 represents an important part of the radiative forcing by 2050 due to the CO_2 emitted by kerosene-fuelled airplanes in the period 2000-2050. However, due to the benefits of the other factors with a shorter lifespan, the overall impact is still reasonable. The difference between both scenarios can be compared to a current radiative forcing of about 2.5 W/m^2, or a reduction of 1-1.5% from current levels.

Annex 5.
EXISTING HYDROGEN REFUELLING STATIONS

Table A5.1

Existing hydrogen refuelling stations

		Compressed gaseous H_2	Liquid H_2	Liquid to compressed H_2
1	SWB filling station [1988 - 1999]		X	
2	BMW Company Refueling Station [start 1989]		X	
3	Bavarian Bus Demonstration Project; skid-mounted LH_2 refueling by Linde for MAN LH_2-ICE bus demonstration in Erlangen [04/1996 – 02/1997] and Munich [05/1997 – 08/1998]; a driving experience of 45 000 km was accumulated [in 2003 still the largest accumulated operating range by any hydrogen bus run in public passenger transport service worldwide], project coordination by LBST		X	
4	Renault FEVER PEMFC passenger car demonstration, France [operated during 1998]		X	
5	Clean Air Now – El Segundo, LA, USA [since 1995]	X		
6	Hamburg Van Demonstration Project (W.E.I.T.), Hamburg, Germany [operative between 01/1999 and spring 2002]	X		
7	Oberstdorf, Germany - Refuelling station for the Neoplan fuel cell bus [trial operation in 1999]	X		
8	Chicago Transit Authority Ballard PEMFC Bus Demo, APCI delivered LH_2, Chicago, Ill., USA [03/98-02/2000]			X
9	British Columbia Transit - Ballard PEMFC Bus Demo, Vancouver, BC, Canada [10/98 – 09/2000]	X		
10	DaimlerChrysler Company Refuelling station, Nabern, Germany [start 1998]		X	
11	VW company refuelling station, Wolfsburg, Germany [since 2001 ?]		X	
12	Ford Vehicle Refuelling Dearborn, H_2 delivered by APCI [started in 1999]		X	X
13	Munich Airport Vehicle Project [start-up 05/99]; LH_2 trucked-in by Linde, CGH_2 produced from a pressurised GHW electrolyser or evaporated from LH_2; LH_2 refuelling station is the first public refuelling station in the world; three articulated MAN ICE buses have accumulated more than 300,000 km of uninterrupted operation	X	X	X
14	Sunline Transit, Thousand Palms, CA – electrolytic H_2 generation and compression to 34.5 MPa – operation of Ballard P4 bus [start APR2000]			
15	Schatz H2 Generation Center at Sun Line Transit in Thousand Palms, CA – PV electrolytic H2 generation with Teledyne electrolyser and compression to 25 MPa – [original start-up in 1994, improved in FEB2001]	X		
16	HydroGen PSA Van Demonstration [1st half of 2000]			X
17	MAN-Siemens-Linde PEMFC Bus Demo in Erlangen, Nuremberg and Fürth, Bavaria, Germany; mobile CGH2 refuelling station with trucked-in hydrogen, delivery and operation by Linde [10/2000 – 04/2001], project coordination by LBST	X		

Table A5.1 (continued)

Existing hydrogen refuelling stations

		Compressed gaseous H_2	Liquid H_2	Liquid to compressed H_2
18	California Fuel Cell Partnership, Sacramento, CA [NOV2000]		X	X
19	Honda company refuelling station for CGH_2 [opened in 2001]	X		
20	Toyota company refuelling station for CGH_2 [opened in 2001]	X		
21	South Korea; Hyundai Motor Company; company refuelling station for 41 MPa CGH_2; Pressure Products Industries Inc. and Doojin Corp. [opened in 2001]			
22	Osaka, Japan; PEMFC Vehicle Demonstration by WE-NET [opened 07FEB2002] with Natural Gas reforming, besides 35 MPa CGH_2 refuelling also the filling of metal hydride tanks is possible	X		
23	Takamatsu, Japan; PEMFC Vehicle Demonstration by WE-NET [opened 28FEB2002 and closed FEB2005] with PEM electrolyser, besides 35 MPa CGH_2 refuelling also the filling of metal hydride tanks is possible	X		
24	BC HydroGen – refuelling station for 70 MPa CGH_2 to be erected in Surrey, BC, Canada; hydrogen via electrolysis from renewable energy [start: fall of 2001]	X		
25	LH_2 manual power assisted refuelling station and LH_2 storage both provided by Linde with fuel delivered by Air Products at BMW's NA Engineering and Emissions Test Center in Oxnard, California [12JUL2001]		X	
26	American Honda Motors Co. Inc., Research and Development Center, Torrance, California – PV-electrolysis and grid-connection [20JUL2001]	X		
27	DoE Vehicle Testing Center, Arizona Public Service &DoE, Phoenix, AR, Proton Energy PEM electrolyzer [started 2001]	X		
28	Tsurumi, Japan; PEMFC Vehicle Demonstration by WE-NET [opened AUG 2002], chemical by-product hydrogen from soda production, 35 MPa CGH_2 refuelling, succeeded by ENAA as JHFC demo since DEC2004	X		
29	Davis, University of California, Hydrogen Bus Technology Validation Program [since2002]	X		
30	LH_2 supplied refuelling station by Linde for Opel in Dudenhofen, dispensing of LH_2 and 70 MPa CGH_2 [operative since 2002]	X	X	X
31	LH_2 supplied refuelling station by Linde for DaimlerChrysler in Sindelfingen, dispensing CGH_2 at 35 MPa and 70 MPa [35 MPa operative since 2002]			X
32	TotalFinaElf & BVG Hydrogen Competence Center Berlin, LH_2 technology and trucked-in LH_2 by Linde, Proton Energy Systems PEM electrolyser; planned to the refuelling of FC city buses in the coming years; possible extension by onsite methanol reforming to hydrogen, this station will refuel the IRISBUS FC Buses in Berlin within the CITYCELL project. [23OCT2002]	X	X	X
33	AC Transit in Richmond, California, Stuart Energy Systems PEM electrolyser, first CaFCP satellite station [opened 30OCT 2002]	X		
34	Northern Nevada Test Site [100 km north of Las Vegas]; Nevada Test Site Dev. Corp., DoE, Corp. For Solar Technologies and Renewable Resources, and City of Las Vegas, multi-fuel station for CNG, CGH2, Hythane including a 50 kW Plug Power PEMFC operated by APCI [started 15NOV2002]	X	?	?

Table A5.1 (continued)

Existing hydrogen refuelling stations

		Compressed gaseous H_2	Liquid H_2	Liquid to compressed H_2
35	Tokai, Aichi Prefecture, Japan; Toho Gas Co.'s research laboratory refueling station with a capacity of 40 Nm^3/h, hydrogen production via steam reforming [opened OCT2002]	X		
36	Kasumigaseki, Tokyo, Japan; ENAA re-locatable 35MPa/25MPa CGH_2 refuelling station operated by Taiyo Nippon Sanso, hydrogen from a bundle of high-pressure cylinders, JHFC demo [opened DEC2003]	X		
37	Yokohama, Kanagawa Prefecture, Japan; ENAA 35MPa/25MPa CGH_2 refuelling station operated by Cosmo Oil, reforming of clean gasoline to hydrogen; JHFC demo [opened MAR2003]	X		
38	Yokohama, Kanagawa Prefecture, Japan; ENAA 35MPa/25MPa CGH_2 refuelling station operated by Nippon Oil, naphtha reforming to hydrogen; JHFC demo [opened APR2003]	X		
39	Ariake, Tokyo, Japan; ENAA LH_2 and 35MPa/25MPa $LCGH_2$ station operated by Iwatani Intl. Corp. and Showa Shell Sekiyu KK; JHFC demo as well as Tokyo Metropolitan Government project [opened in JUN2003]		X	X
40	Kawasaki City, Kanagawa Prefecture, Japan; ENAA 35MPa/25MPa CGH_2 refueling station operated by Japan Air Gases (Subsidiary of Air Liquide Japan, hydrogen from methanol reforming ; JHFC demo [opened SEP2003]	X		
41	Senju, Tokyo, Japan; ENAA 35MPa/25MPa CGH_2 refuelling station operated by Tokyo Gas and Taiyo Nippon Sanso, hydrogen from LPG reforming; JHFC demo [opened MAY2003]	X		
41	Hadano, Kanagawa Prefecture, Japan; ENAA 35MPa/25MPa CGH_2 station operated by Idemitsu Kosan, hydrogen from Kerosene reforming; JHFC demo [opened APR2004]	X		
42	Sagamihara, Kanagawa Prefuecture, Japan; ENAA 35MPa/25MPa CGH_2 station operated by Kurita Water Industries, Itochu Enex and Shinanen, hydrogen from conventional water electrolyser; JHFC demo [opened MAY2004]	X		
43	Ome, Tokyo, Japan; ENAA re-locatable 35MPa/25MPa CGH_2 station operated by Babcock Hitachi and Taiyo Nippon Sanso, hydrogen from natural gas reforming; JHFC demo [opened JUN2004]	X		
44	Seto-South, Aichi Prefecture, Japan; ENAA 35MPa CGH_2 stataion operated by Toho gas and Taiyo Nippon Sanso, hydrogen from natural gas reforming; JHFC demo [opened FEB2005 and closed SEP2005]	X		
45	Seto-North, Aichi Prefecture, Japan; ENAA 35MPa CGH_2 station operated by Nippon Steel and Taiyo Nippon Sanso, hydrogen from COG (coke oven gas) of steel industry; JHFC demo [opened FEB2005 and closed SEP2005]	X		
46	DoE/NREL Blueprint – Installation of Infrastructure [2003] and validation of fleet vehicle refuelling [2004]	X	?	X
47	Toyota Refuelling Stations in California [up to 6 stations by 2003], one with Stuart Energy electrolyser unit in Toyota's US headquarter in Torrance, California	X		

Table A5.1 (continued)

Existing hydrogen refuelling stations

		Compressed gaseous H_2	Liquid H_2	Liquid to compressed H_2
48	Refuelling station of Clean Energy Partnership Berlin – Aral, BMW, BVG, DaimlerChrysler, Ford, GHW, MAN and Opel, comprising trucked-in LH_2 by Linde and CGH_2 produced onsite in a GHW pressurised electrolyser and conventional fuels [scheduled start-up end of 2003]	X	X	X
49	Ottobrunn $LCGH_2$ refueling station; operator Energie-Technologie GmbH; refuelling of one MAN ICE bus [scheduled start be end of 2003]			X
50	Refuelling of PEMFC Irisbus City Bus at a CGH_2 refuelling station supplied with hydrogen from hydropower via electrolysis in Torino, Italy (Consortium: ATM, Irisbus Italia, Sapio, CVA , Ansaldo Ricerche, Ministry of the Environment and ENEA) [Start of public bus demonstration planned since 2002 – delayed due to regulatory difficulties - this station most likely will refuel the IRISBUS fuel cell bus within the CITYCELL Project]	X		
51	The EU-funded CUTE bus demonstration supports operation of three DC Citaro FC buses each at a site; CGH_2 storage pressure is 35 MPa; each location has differing hydrogen generation features			
52	Amsterdam, The Netherlands; partners are Shell Hydrogen, Nuon, GVB Amsterdam, Hoekloos and Milieudienst Amsterdam; renewable electricity based pressurised electrolysis provided by Vandenborre Technologies (IMET 60)	X		
53	Barcelona, Spain; partners are TMB Barcelona and BP; grid and partly PV-derived electricity fuel a pressurized electrolyser provided by Vandenborre Technologies (IMET 60 type)	X		
54	Hamburg, Germany; partners are HHA Hamburg, HEW/Vattenfall Europe and BP; production of 45 MPa CGH^2 for onsite storage via pressurised Norsk Hydro electrolyser from green certified electricity	X		
55	London, Great Britain; partners are London Buses, First Group and BP; LH_2 delivered by trucks, evaporation to CGH_2	X		
56	Luxembourg; partners are Air Liquide, Ville de Luxembourg, FLEAA, Economics and Transport Ministry and Shell; CGH_2 delivery in trailers to the refuelling station	X		
57	Madrid, Spain; partners are Air Liquide, Gaz Natural, Repsol YPF and EMT Madrid; hydrogen is produced onsite from natural gas by a Carbotech compact reformer, H_2 back-up supply is provided by CGH2 tube trailers from chemical by-product generation.This station will not only supply hydrogen to the CUTE project funded buses but also to an Irisbus FC bus funded in the CITYCELL project.	X		
58	Oporto, Portugal; partners are STCP Porto and BP; onsite reforming of natural gas to hydrogen, compression, storage and dispensing	X		
59	Stockholm, Sweden; partners are SL Stockholm, Busslink, Stad Stockholm and Fortum (Birka Energi); hydrogen is produced from green certified hydro-electricity via pressurised electrolysis supplied by Vandenborre Technologies (Stuart Energy Systems)	X		

Table A5.1 (continued)

Existing hydrogen refuelling stations

		Compressed gaseous H_2	Liquid H_2	Liquid to compressed H_2
60	Stuttgart, Germany; partners are Stuttgarter Straßenbahnen AG SSB, Neckarwerke Stuttgart NWS, Switch and BP; hydrogen production from natural gas via a compact steam reformer, purification, pressurisation, storage and dispensing	X		
61	Reykjavik, Iceland, ECTOS bus project demo, onsite pressurised Norsk Hydro electrolyser operated with hydro- and geothermal electricity, Shell is 35 MPa CGH_2 refueling station operator, three DaimlerChrysler FC Citaro buses	X		
62	Leuven, Belgium, first European combined refuelling station for LNG, LCNG and $LCGH_2$, by Citensy, a subsidiary of Electrabel and Distrigas, with equipment from NexGen a division of Chart Industries	X		
63	Hydrogen liquefier and vehicle refuelling station to be erected by AEM, SOL, and others in a hydrogen and fuel cell demonstration center in Bicocca near Milano	X	X	
64	Washington DC refuelling station, by GM and Shell, six GM HydroGen 3 vehicles to be demonstrated		X	X
65	VTA, San Mateo Transportation District, CaFCP and CARB, LH_2 delivery by APCI	?	?	?
66	Perth, Western Australia; partners are Commonwealth Government, DaimlerChrysler, Murdoch University, BP, Path Transit, Smart Track and UNEP; by-product hydrogen from BP's oil refinery in Kwinana will be piped to the BOC site next door where it will be purified and pressurised. The compressed hydrogen will then be trucked to the bus depot and off-loaded to the refuelling facility, from which the hydrogen fuel cell buses will be refuelled.	X		
67	EUHYFIS – European Hydrogen Filling Station	X		
68	Refuelling of PEMFC Irisbus City Bus at a CGH_2 refuelling station to be erected in Paris; the demonstration will be part of the CITYCELL project	X		

Source: LBST, 2003; Nakui, 2003

Annex 6.

DEFINITIONS, ABBREVIATIONS, ACRONYMS AND UNITS

This section provides definitions of the energy, economic and financial terms and the regional groupings used throughout this publication.

Fuel and process terms

Readers interested in obtaining more detailed information should consult the annual IEA publications *Energy Balances of OECD Countries, Energy Balances of Non-OECD Countries, Coal Information, Oil Information, Gas Information and Electricity Information*.

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.

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.

Electricity production

Is the total amount of electricity generated by power plants. It includes own-use and transmission and distribution losses.

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 oil products. 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 40-60%. 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.

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.

Hydro

Hydro refers to the energy content of the electricity produced in hydropower plants assuming 100% efficiency.

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 degrees Celsius at atmospheric pressure. In this way, the space requirements for storage and transport are reduced by a factor of over 600.

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 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

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, *i.e.* makes allowance for the differences in price levels and spending patterns between different countries.

Scenario

An analysis dataset based on a consistent set of assumptions.

REGIONAL GROUPINGS

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 and other developing Asia, Central and South America, Africa and the Middle East.

Former Soviet Union (FSU)

Comprises: Armenia, Azerbaijan, Belarus, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Moldova, Russia, Ukraine, Uzbekistan, Tajikistan and Turkmenistan.

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.

Organization 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.

ABBREVIATIONS AND ACRONYMS

AC	Alternating current
AFC	Alkaline Fuel Cell
AFR	Africa
ASU	Air Separation Unit
ATR	Autothermal Reforming
AUS	Australia and New Zealand
BOP	Balance of Plant
CAN	Canada
CC	Combined cycle
CCS	CO_2 Capture and Storage
CDM	Clean Development Mechanism
CERT	Committee on Energy Research and Technology
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
CSA	Central and South America
CSS	Cyclic Steam Stimulation
CTL	Coal-to-liquids
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
DRI	Direct Reduced Iron
EEU	Eastern Europe
ELAT®	Solid Polymer Electrolyte Electrode
EPA	Environmental Protection Agency, United States
EOH	Ethanol
EOR	Enhanced Oil Recovery
EPR	European Pressurized water Reactor
ETP	Energy Technology Perspectives
ETSAP	Energy Technology Systems Analysis Programme
EU	European Union
EUR	Euro
FCB	Fuel Cell Bus
FCV	Fuel Cell Vehicle
FSU	Former Soviet Union
FT	Fischer-Tropsch
GDE	Gas Diffusion Electrode
GDL	Gas Diffucion Layer
GDP	Gross Domestic Product
GEF	Global Environment Fund
GHG	Greenhouse Gas
GIS	Geographical Information System
GTL	Gas-to-Liquids
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
IGCC	Integrated Gasification Combined Cycle
IND	India
IPCC	Intergovernmental Panel on Climate Change
IPHE	International Partnership for a Hydrogen Economy
JI	Joint Implementation
JPN	Japan
KOH	Sodium Hydroxide
LDV	Light Duty Vehicle
LH_2	Liquid hydrogen
LHV	Lower Heating Value
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
LULUCF	Land Use, Land Use Change and Forestry
MCFC	Molten Carbonate Fuel Cell
MEA	Middle East

MeOH	Methanol
MEX	Mexico
MOF	Metal-Organic Framework
MTBE	Methyl Tertiary Butyl Ether
NGCC	Natural Gas Combined Cycle
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
PAFC	Phosphoric Acid Fuel Cell
PCSD	Pressure cyclic steam drive
PEC	PhotoElectrochemical Cell
PEMFC	Proton Exchange Membrane Fuel Cell
PISI	Port Injection Spark Ignition
PFBC	Pressurized Fluidized Bed Combustion
POX	Partial Oxidation
PSA	Pressure Swing Absorption
Pt	Platinum
PV	PhotoVoltaics
RD&D	Research, Development and Demonstration
SAGD	Steam Assisted Gravity Drainage
SECA	Solid State Energy Conversion Alliance
S-I cycle	Sulfur-Iodine cycle
SKO	South Korea
SMR	Steam Methane Reforming
SO_2	Sulfur dioxide
SOEC	Solid Oxide Electrolyser Cell
SOFC	Solid Oxide Fuel Cell
SUV	Sports Utility Vehicle
TPES	Total Primary Energy Supply
UNEP	United Nations Environment Programme
USA	United States of America
USD	United States Dollars
VHTR	Very High Temperature Reactor
WBCSD	World Business Council for Sustainable Development
WEO	World Energy Outlook
WEU	Western Europe
WHO	World Health 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
kWth	kilowatt thermal capacity
kWel	kilowatt electric capacity
bbl	(blue) barrel
BOE	Barrels of Oil Equivalent. 1 BOE = 159 litres
°C	degrees Celsius
kWh	kilowatt-hour
mD	millidarcies = 10^{-3} darcies
mils	0.001 US dollar
MPa	megapascal = 10^6 Pa
Nm3	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
cP	centiPoise
%wt	weight percent

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