Technologies for Alternative Energy

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1. Introduction

In Papers 5 and 6 technologies for the main sources of energy consumption were discussed. In Papers 7 and 8 the attention is focussed on technologies that impact on emissions from energy production. Table 1 provides data on the main sources of GHG emissions in the advanced economies for the year 2000.

Table 1. Sources of GHG Emissions in the Advanced Economies, 2000

Source of emissions	Tg CO_2 -e	% of total
Electricity and heat production	3831.2	76.3
Petroleum refining	420.7	8.4
Other energy production (coal and gas transformation)	324.6	6.5
Fugitive emissions (coal, oil and gas)	441.5	8.8
Total energy production	5018.1	38.1 (a)
All sources of emissions	13175.3	

Note: (a) energy production as % of all sources of emissions.
Source: CSES (2004).

Papers 7 and 8 focus on emissions from the production of electricity and heat, which represent 76.3% of all emissions related to energy production. The other sources of emissions are not discussed in detail in this report. Coverage of the issues relating to these sources of emissions is given in CSES (2004). Incremental technological change is giving rise to modest improvements in energy efficiency in petroleum refining and the transformation of gas and coal. There are no apparent dramatic changes in technology in sight.

Fugitive emissions are associated with the mining/drilling for fossil fuels and their distribution. These emissions are in the form of methane and nitrous oxides. The rate of improvement in mining technologies is leading to a significant reduction in the emissions-intensity of resource extraction.

Table 2 outlines the current shares of particular sources of energy in world electricity generation in 2002.

This paper concentrates on technologies used in alternative sources of energy, which comprise 34.7% of total electricity generated. Paper 8 discusses emissions-saving technologies in relation to the use of fossil fuels in electricity generated.

Alternative energy comprises renewable sources of energy (hydro; biomass; wind; geothermal; solar, which includes photovoltaics and solar thermal [concentrating solar power]; and ocean sources, comprising tidal, wave, marine currents, ocean thermal energy and tapping the salt gradient), nuclear power, and waste. The use of renewable sources of energy can be optimised if advanced energy storage systems are developed and employed, so energy storage is another topic covered in this paper. Finally, the use of hydrogen as an energy carrier, while at present an adjunct of fossil fuel-based energy, is seen as being a key facet of a renewable-energy-based system in the very long run. Hence the issues pertaining to the future development of hydrogen in the energy system are discussed in this paper.

Table 2. Shares of World Electricity Generation in 2002

Energy source	% of total electricity generation
Coal	38.83
Oil	7.35
Gas	19.10
Fossil fuels	*65.27*
Nuclear	16.51
Hydro	16.24
Biomass & waste	1.29
Other renewables	0.69
Of which:	
Wind	0.32
Geothermal	0.35
Solar	0.01
Ocean	0.01
Alternative Energy	*34.73*

Source: Derived from IEA (2004a, p. 432).

2. The Technologies

Nuclear Power

Current Prospects

Nuclear power was introduced in the 1950s and gained momentum after the oil shocks of the 1970s. Annual capacity additions averaged around 12 GW in the 1970s and 18 GW in the 1980s, but slowed to just 2.5GW per year in the 1990s, primarily because lower fossil-fuel prices and lower up-front capital requirements made generation from coal and gas more attractive. Increasing public concern about nuclear safety was also a factor, particularly after the Chernobyl accident in 1986.

IEA (2004a) makes the following projections for nuclear power out to 2030 in its BAU Scenario.

- Between 2002 and 2030, nuclear power generated is expected to increase by just 10% for the world as a whole.
- Over this same period, nuclear power generated in the OECD is projected to decline by 6% while increasing by 109% in the rest of the world.
- Nuclear power generated as a proportion of total electricity and heat generated is expected to decline from 18.4% in 2002 to 11.5% in 2030, and as a percentage of TPES to fall from 6.7% to 4.6%.

Nuclear energy is unconstrained by resource availability in the medium term and produces no direct GHG emissions. However, new construction of nuclear power systems in the advanced economies will be constrained by three factors: (i) high capital costs compared to alternative technologies; (ii) political decisions in a large number of countries to phase out nuclear power;[1] and (iii) community opposition to nuclear plants which can lead to construction delays that result in unattractive economics and perceived financial risk (*The Economist* 2001).

Some seventy-five per cent of existing nuclear capacity in OECD Europe is expected to be retired by 2030, with only France anticipating a large-scale replacement of its nuclear base before 2030. However, in June of this year TVO, a Finnish consortium, started work on the first new nuclear plant to be built on either side of the Atlantic in a decade (*The Economist* 2005b). No new plants have been built in the United States since the accident at Three Mile Island in March 1979. However, most existing power plants are expected still to be in operation in 2030. Many existing nuclear units will be able to increase their power capacity (IEA 2004a).

Since the IEA undertook its last energy projections in late 2004 the outlook for the nuclear power sector has changed somewhat. Climate change is helping a revival of the nuclear industry. In Asia the prospects are excellent. China already has nine nuclear reactors, and is planning to commission a further 30. New capacity is being considered in India, Japan and South Korea. Russia has several plants under construction (*The Economist* 2005b).

Technological Prospects

Relative to other energy sources, current nuclear power plant designs have very high capital costs per MW. Operating and maintenance costs are also higher. These costs are not fully offset by the relatively low fuel cost of nuclear power plants. No country has a complete concept of the facilities and operations that will be necessary for decommissioning and waste disposal, nor the costs of ensuring that nuclear materials do not end up in the hands of terrorists. As a consequence there is considerable uncertainty in any estimate of the social costs for future projects. The agenda for technological development is to address these important economic and social constraints on the growth of the nuclear power industry.

Specific goals of new plant designs are to reduce construction cost, construction time, operating and maintenance costs and fuel-cycle costs, while improving operating safety. Approaches to achieving these goals include:

- reducing the number of components in the primary and secondary system, to lower capital and operating costs;
- using factory assembly and modularisation, to reduce construction costs and schedules;
- reducing the reactor size to 300 MW or less, to reduce the cost of the generation unit and shorten the construction schedule; and
- simplifying and reducing the cost of all safety systems and processes, ranging from hardware systems to inspection and testing; and achieving waste management goals, such as using thorium as a major component of the reactor

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[1] These reflect concerns about the safety of nuclear plants and the disposal of nuclear waste.

> fuel and reducing the specific volumes of low- and medium-level wastes (*The Economist* 2001).

In the longer run, reactor safety, and long-term secure and safe storage of spent fuel and irradiated material should become the main focus of nuclear research. New and safer reactor concepts should be explored; in particular reactors that produce less radioactive waste and that reduce the likelihood of catastrophic accidents. Sites and technologies for long-term disposal of waste should be studied. Existing methods of waste disposal remain totally inadequate. No country has yet built a 'permanent' waste-disposal site. Even state-of-the-art geological storage is not the final answer. Perhaps the Australian developed Synroc process might provide an answer to waste disposal.[2] Finally, the issue of nuclear terrorism and the safety of nuclear materials needs to be addressed through appropriate security protocols. Significant governmental R&D support may be necessary to meet all of these safety-related objectives (IEA 2003a).

Fusion Technology

Nuclear fusion, in which energy is produced from the reaction between isotopes of hydrogen deuterium and tritium, may be a longer-term option. Fusion power has the potential to become an inexhaustible source of economical and safe baseload electrical power in the second half of this century.

Producing neither carbon dioxide nor long-lived radioactive substances, fusion power has numerous inherent safety features. Eventually, reactions involving deuterium only or deuterium and helium may be used. Deuterium is abundant, as it can be extracted from water. Tritium does not occur naturally but can be manufactured from lithium, which is plentiful in the earth's crust. Extensive R&D by several countries has so far yielded disappointing results and the view of the International Energy Agency in 2001 was that fusion technology is unlikely to be commercialised until 2050 at the earliest (IEA 2001). Part of the reason why commercial fusion reactors have long remained 30 years away is that increasing the size of the reactors to something big enough to be a power plant proved harder than foreseen. But it may also be the case that delays in decision-making and inadequate funding levels have impeded progress.

Research expenditures on nuclear fusion peaked some twenty years ago, and have since declined significantly. However, efforts to exploit fusion power's potential will shortly pass a significant milestone with the construction of the world's first fusion experimental plant, producing some 500 MW of pulsed thermal power. The device will demonstrate all the major systems needed to show how the fusion process can produce thermal energy. The development of this testing facility is an international

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[2] The Synroc process for treating high-level radioactive waste was developed by the Australian Nuclear Science and Technology Organisation. It has been undergoing development for more than 25 years. In the Synroc process, contaminated waste is mixed with minerals and subject to intense pressure to create a synthetic rock that, mimics the properties of natural rock. Synroc's advantage has been that it locks up radioactive waste in a more stable form than the traditional glass encapsulation technology (Roberts 2005).

project bringing together scientists and engineers from China, the European Union, Japan, Korea, Russia and the United States. The project is named ITER, and builds on many years of experimental and theoretical work, notably using the Tokamak[3] devices first invented in Russia in the 1960s to contain and control the fusion process. Established under the auspices of the International Atomic Energy Authority, ITER assembles the world's foremost body of scientific knowledge and know-how on fusion physics and technology. The project is now about to enter the construction phase before the start of the experimental program. The costs involved in conducting fusion research are enormous. The budget for ITER involves spending $US5 billion on construction, $5 billion on operating costs over 20 years and more than $1 billion on decommissioning (*The Economist* 2005a).

In Europe and Japan, further studies will focus on designs for DEMO, a power plant that will bridge the gap between ITER and the first generation of commercial power plants. In the United States, studies will focus on commercial power plant designs based on an alternative to the standard Tokamak concept that has potential for further improved economic performance (IEA 2005a).

Conclusions

Compared with the BAU scenario in which nuclear power is expected to decline to 4.6% of TPES by 2030, the SD Vision Scenario projects a revival in the nuclear industry which could increase to more than 15% by 2030 and an even higher proportion of total energy by 2050.

Renewable Energy

Overview

Between 1970 and 1990 the growth of renewables' energy rose by an average 2.8% per annum and their share of TPES rose. However, during the 1990s renewables' share of TPES fell and the growth rate declined to an average 1.2% per annum. The strong performance of renewables in the 1970s and 1980s stemmed largely from higher fossil fuel prices and from policy support for hydropower, geothermal and traditional forms of biomass (IEA 2005b). Growth in the major forms of renewables – hydro and geothermal in particular – slowed during the 1990s even though newer forms of energy such as wind were more effectively utilised.

The BAU Scenario of the IEA (2004a) provides projections for renewable energy from 2002 to 2030. If we take energy from biomass and waste out of the equation (the larger part of this energy is provided by traditional biomass burning in the developed countries) so that the focus is on such forms of renewable energy as hydro, wind, geothermal, solar and ocean, the following picture emerges.

- The global supply of renewable energy increases by 366% (or 5.6% per annum) between 2002 and 2030, with growth being faster in the advanced economies than the developing economies.

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[3] A tokamak is the most successful device yet found for magnetic confinement of plasma.

- However, as a proportion of TPES renewables increase from 0.5% to 1.6% over this period.
- Some five-sixth of renewables energy is used in electricity and heat generation, and its share of total electricity and heat generated is expected to rise from 1.2% in 2002 to 3.2% in 2030.[4]
- The share of renewables in TFEC is expected to increase from 0.1% to 0.4% over the same period.

The main constraint on the adoption of renewable energy is its cost when compared with conventional energy sources. The high cost of renewables occurs as a result of their high capital costs.

The capital costs of renewables are expected to decline over the coming decades, representing a continuation of earlier trends. The rate of decline will be directly correlated with the rate at which they are deployed (through the realisation of scale economies and learning economies) and inversely correlated with the maturity of the technology (and hence the scope for further technological breakthroughs). The fastest rate of decline should come in the capital cost of photovoltaics, which are currently the most capital-intensive renewable technology, but substantial decreases are also expected in the capital costs of offshore wind, solar thermal and tidal and wave technologies. The capital cost of hydro, the most mature technology, is expected to remain broadly unchanged. The cost of renewables for electricity generation depends on the capital cost of the technology and on the quality of the resource being tapped (such as wind strength and hours of clear sunlight). While the generating costs of most renewables will decline as a consequence of falling capital costs, some renewables will become more expensive in some areas because the best sites for them will already have been exploited (e.g. hydropower and onshore wind in many parts of Europe, IEA 2004a).

The success of current and planned R&D efforts will be among the key factors that determine whether advanced renewable-energy technologies capture a significantly higher share of global primary energy supply than our basic forecasts allow for in the longer term. The principal goals of these R&D efforts include reducing the cost of energy production from renewable resources, increasing the quality of energy delivered and the reliability of renewable-energy supplies, and improving the matching of energy supply with end-user demand so as to reduce costs and losses in energy transport and distribution. Energy storage technologies, considered in a later section of this paper, are also important to greater use of renewable-energy technologies.

Technological trends that contribute to a narrowing of the cost gap between renewable energy and conventional energy are likely to be complemented by regulator and policy trends that encourage the take-up of renewable energy.

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[4] However, the SD Vision Scenario projected other renewables to move to 19% of TPES by 2050.

Natural Cycles in Renewables

The integration of larger amounts of renewables will become an increasingly important issue for the management of electricity grids. A characteristic of many forms of renewables is their natural cycles of available energy. Renewables by their very nature vary their output with natural conditions, albeit, depending on the technology, on different timescales. These fluctuations of renewable electricity output can pose challenges in managing electricity grids. On the other hand, hydropower (pumped-storage) has been used for a long time to level out short- and medium-term fluctuations in electricity production and consumption. Hence the issue of unmatched demand and supply is not completely new.

The most prominent example in media and policy discussions of intermittency is in relation to wind power. However, natural cycles of different timing and amplitude also exist for other renewables, including hydropower, geothermal, biomass, solar photovoltaics and wave and tidal energy. Natural cycles can be of relatively short-term duration (intra-day or inter-day) as well as of long-term duration (seasonal changes). Timescales vary from minutes (solar, wind) to hours (solar, wind, wave/tidal), days (solar, wind, wave/tidal, hydro), seasonal (solar, wind, wave/tidal, hydro and biomass), yearly (solar, wind, hydro, biomass and geothermal) and finally generations (biomass and geothermal).

Since natural variations of resource availability do not correspond with the variable need of consumers, balancing supply and demand is a critical issue, potentially requiring backup by other means of energy supply. Hourly changes in output require balancing of short-term fluctuations by an operational reserve, while days with low output require balancing through capacity reserves. Conversely, exceptionally windy days or rainy seasons can produce a surplus of supply and there might be an issue of handling excess capacity where grids are not sufficiently interconnected. On the other hand, hydropower has played an important role as backup power and electricity storage for years. Together with other renewables such as biomass and geothermal it also has the potential to serve as backup power as shares of renewables in electricity supply increase.

Currently, natural cycles of renewables have become an issue to grid operations at a regional level because of fluctuations in hydropower and wind. Other renewables technologies have either not yet reached a level of penetration where their variations are of importance for balancing the electricity system (e.g. solar photovoltaics), or have been integrated relatively successfully (e.g. geothermal energy).

Norway’s electricity production, for example, is 99% based on hydropower. It has to be able to cope with years of below-average rainfall to maintain its electricity supply. The main avenue used to cope with these fluctuations is hydro-storage and interconnection with its neighbouring countries in Scandinavia and market reforms that allow for transparent signalling of supply shortages and overcapacities to induce market participants to adjust supply into and out of Norway when necessary.

Some renewable technologies actually complement one another in their cycles. Solar PV resources are most available in summer while this is in many climates a time of relative drought with respect to hydro resources. Winds are often stronger in winter which is also a time of peak demand in colder climates.

However, renewable energy resources might not always be distributed equally. Some countries benefit from very windy regions while others have good biomass or hydro resources. While relying on one technology alone might be feasible if there is relative abundance or low penetration into the market, in the long run wider interconnection, and thereby utilisation of dispersed renewable energy sources on a wider geographic scale, is likely to become an important means of mitigating problems with availability due to the natural cycles.

A strategy to develop renewables needs to take account of the different natural cycles that influence their availability. The portfolio of renewable technologies needs to be fully utilised to reap its full potential. Renewable energy technologies stand to benefit from markets which are widely integrated and where a wide variety of options, including demand-side response, storage, distributed generation and flexible power plants compete to offer the various ancillary services. This is the way to enable renewable energy to become mainstream in its characteristics (IEA 2005c).

Hydro Power

Prospects

The World Economic Outlook projections made by the IEA in 2004 (IEA 2004a) showed the following situation for hydropower.

- Globally hydropower would contribute an increase in electricity generated of 63% between 2002 and 2030 although its share of total electricity generated would ease from 6.0% to 5.5%.[5]
- In the OECD hydropower's energy contribution would increase by 24% and its share of total electricity generated decline from 5.0% to 4.6%.
- In the Rest of the World hydroelectricity generated would increase by 98%, but it share of total electricity generated would fall from 7.3% to 6.2%.

In the OECD the best sites for hydropower, taking into account their energy potential and environmental considerations, have already been developed, although there is some room for upgrading existing capacity and for new small hydro schemes. However, Canada, Turkey and Japan are expected to develop considerable new hydro resources. Developing countries will account for 80% of the projected increase in hydroelectricity between now and 2020, three-quarters of that being in China and Latin America. Competing uses, such as for water supply, irrigation and flood control, are likely to influence the decision for the development of new hydropower projects.

Hydro is a capital-intensive option for electricity generation, but the cost per unit of electricity generated is low in good sites. High initial investment is an important issue. Developing countries may find it difficult to raise the funds to finance new projects (IEA 2001).

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[5] By 2050 the share of hydro in world electricity generated could be expected to fall to 4%.

Natural Cycles

The capacity of a hydro plant to produce electricity ultimately depends on the water cycle providing seasonal rain and runoff from the snow pack. Seasonal variations determine the water level in the river and thus the strength of the water flow and its implicit available energy. Dams are often built in mountainous regions where the natural topography can be used to create artificial lakes at low costs. Again, seasonal variability determines the availability of water and thus the total potential energy that can be stored in the artificial lakes.

Hydropower today is the main energy carrier to store electricity on a large scale. Besides the natural accumulation of water in reservoirs, pumped-storage facilities offer the opportunity to pump water and thus potential energy upstream and release it again when required. The typical round-trip efficiency of this method is around 80%.

Drought periods will impact adversely on the capacity of hydropower systems. They are a particular problem in warm climates when they coincide with annual peak demand on the energy system. But the variability of precipitation can present problems even in cool climates. Norway, which is 99% dependent on hydropower, is an interesting example. Annual electricity production from hydropower generally averages about 120,000 GWh. However, low annual rainfalls between 1995 and 1996 resulted in a drop in annual electricity production of about 17,000 GWh (IEA 2005c).

Environmental Issues

The environmental and social effects of large-dam construction are the subject of much controversy. Large-scale hydropower may disturb local ecosystems, reduce biological diversity or modify water quality. It may also cause socio-economic damage by displacing local populations. A number of projects in developing countries have been stalled or scaled down because of such problems. Although these ill effects can be managed and mitigated to some degree, they may affect the future of hydropower in general. Obtaining loans from international lending institutions and banks for major hydro projects has become more difficult. Mini- and micro-hydro systems have relatively modest and localised effects on the environment, but the kWh cost is generally higher in smaller systems.

Hydropower emits some greenhouse gases on a life-cycle basis, especially methane generated by decaying bioenergy in reservoirs, but emits far less than the burning of fossil fuels.

Technologies

Despite the longevity of hydro plants and the high availability and reliability of power output, hydropower faces challenges such as public acceptance and the high initial cost and long payback period. The IEA Hydro Implementing Agreement is developing a new program to meet these challenges. It will cover:

- integration of wind into hydropower systems (jointly with the Wind Energy Implementing Agreement);
- safety and security of hydropower facilities;
- best practice for hydropower performance;

- hydropower innovations; and
- development of hydropower in the developing world (where the greatest hydropower potential exists).

Hydropower innovations that show promise are:

- advanced hydropower technologies that eliminate adverse environmental effects such as fish entrainment and the alteration of downstream water quality and quantity;
- irrigation channels that can be modified to provide a water conveyance system for hydropower without impeding the efficiency of overall water management; and
- microprocessor-based switching of the electrical load (which allows a stable system of operation), load management through priority load shedding, a reduced cost of civil engineering components through minimal surge and water hammer effects, and optimal efficiency of operation can bring benefits to micro hydro electric systems (IEA 2005a).

Biomass

Resources and Market Penetration

The traditional biomass resource base used extensively in the developed economies is based on fuelwood. In the advanced economies, the biomass resource base comprises crop residues (particularly rice husks and bagasse), animal wastes, woodland residues, food and fibre processing by-products and purpose grown energy crops (such as high-yielding vegetative grasses, short rotation forest crops and C4 crop plants like sugarcane). Municipal solid waste (MSW), and to a much lesser extent, municipal wastewater, are also utilised as energy resources in the advanced economies. Energy crops are the largest biomass resource in the advanced economies, followed by wood, with animal waste, crop residues and MSW of lesser present significance.

Table 3 provides data on biomass use in energy production and consumption. The cost of producing electricity from bioenergy depends on the technology, the fuel cost, and the quality of the fuel. Most bioenergy used for electricity production is in the solid state. Bioenergy plants tend to be small in size. A typical plant size is 20 MW or less. Bioenergy plants, therefore, have higher capital costs per unit of installed capacity and higher operating costs per unit of electricity produced than fossil-fuel plants.

Bioenergy fuel costs vary widely. The fuel cost can be zero in certain cases, especially if it is a by-product. The bioenergy fuel source must be abundant, reliable and low-cost. Factors that affect the cost of bioenergy supply are competition with other uses, variation in crops and seasonality, and distance from the source.

The electricity-generating costs of bioenergy are, on average, higher than those of fossil-fuel plants because of their higher capital costs, higher fuel costs and lower conversion efficiencies than conventional plants (IEA 2001).

The cost of bioenergy is likely to be reduced in the future because of: (i) increased yields of biomass as a result of increased agricultural productivity and increased urban waste; (ii) the improved conversion efficiency of bioenergy combustion; and (iii) economies of scale associated with the increased use of biomass to generate both electricity and heat (IEA 2003b).

Table 3. Biomass and Energy, 2002 and 2030

(a) Data for 2002 in Mtoe

Energy use	World	OECD	Developing economies
Primary energy supply	1119	181	922
Electricity & heat	76	60	11
Final energy consumption	999	119	869

(b) % change 2002 to 2030

Energy use	World	OECD	Developing economies
Primary energy supply	43	98	32
Electricity & heat	240	145	836
Final energy consumption	29	77	22

(c) % shares

World	2002	2030
Primary energy supply	10.8	9.7
Electricity & heat	2.0	3.9
Final Energy consumption	14.1	11.5
OECD	2002	2030
Primary energy supply	3.4	5.2
Electricity & heat	2.8	5.2
Final energy consumption	3.2	4.2
Developing economies	2002	2030
Primary energy Supply	24.1	15.5
Electricity & heat	1.0	3.3
Final energy consumption	32.0	20.4

Source: IEA (2004a).

Natural Cycles

It is projected that growth in biomass applications will mostly come from new technologies that depend on dedicated plantations and by-products from sustainable forestry. Thus, the supply of biomass depends to a significant extent on the seasonal cycle of these dedicated plants. To increase the use of biomass for electricity generation and heat production, there is an increasing focus on dedicated energy crops such as short-rotation coppice which allow frequent harvest cycles per year. The area that can be planted and the number of harvests per year will determine the maximum amount of energy that can be derived in this way. Should the use of biomass increase significantly in all its applications, these limitations might become more pronounced.

A second, albeit man-made, variability arises when biomass is used in combined-heat-and-power plants (CHP). For example, in the Scandinavian countries, CHP production is dominant for biomass. For industry residues this production is quite constant over the year but for district heating, this results in electricity production of biomass having seasonal variation (production high at winter with high heat load) as well as some daily variations, according to temperature/heat load.

In principle, a global market for biomass products can be envisaged taking advantage of different climates and types of vegetation around the world. The boundaries that seasonal cycles put on the maximum amount of energy derived from biomass can thus be extended. However, ultimately other land use interests and possibly competing uses of biomass itself will put a constraint on bioenergy developments. And global agricultural cycles associated with changing weather will also impact on energy economics if biomass usage increases substantially (IEA 2005c).

Environmental Issues

The use of bioenergy can have many environmental benefits over fossil fuels if the resource is used in a sustainable way. If the land from which bioenergy is produced is replanted, bioenergy is used sustainably and the carbon released will be recycled into the next generation of growing plants. Substituting fossil fuels with bioenergy means the carbon from the displaced fossil fuels remains in the ground and is not discharged into the atmosphere. The extent to which bioenergy can displace net emissions of CO_2 will depend on the efficiency with which it can be produced and used. Biomass is not a zero-emissions technology because of the emissions associated with the production of crops to generate biomass (particularly related to emissions from soil disturbance). Hence, if we are aiming for ZET energy systems in the very long term, biomass should be seen as being more of a medium term source of energy.

Bioenergy plants have lower emissions of SO_X than do coal and oil plants. They may produce, however, more particulate matter than oil- and gas-fired plants. These emissions are in general controllable but they increase generating costs (IEA 2001).

Technology

Currently, most bioenergy applications use direct-fired technology. Solid bioenergy is burned in a process similar to burning coal but with lower efficiencies ranging from 15% to 30%. With cogeneration of heat and electricity, total efficiency is in the order of 60%.

Bioenergy in a gaseous state can be burned in gas turbines (open or combined cycle). Most of it is landfill gas, a low- to medium-calorific value gas that is produced from MSW. The utilisation of landfill gas requires the development of a recovery system with wells or trenches to collect the gas.

Co-firing is the practice of using bioenergy as a supplementary energy source. Bioenergy can be burned along with another fuel, typically coal, but such a process requires modifications or additions to the power plant. Co-firing is a retrofit for existing coal plants to achieve a large-scale introduction of bioenergy in the power sector. Direct addition of solid bioenergy limits the amount of solid bioenergy that can be burned with coal to about 10% to 15%. Solid bioenergy can be gasified and the gas co-fired with coal or with natural gas. If solid bioenergy is gasified prior to co-firing, the percentage that can be added is higher as compared to direct use of solids.

Advanced bioenergy technologies include gasification and pyrolysis. Bioenergy *gasification* technology converts solid biomass into a combustible gas through a partial oxidation process. The gas can be burned in a turbine or fuel cell. Gasification technology is already in an early stage of commercialisation, and accelerated technological progress would greatly enhance future commercial possibilities for the technology. Biomass resources are generally easier to gasify than coal at both the large and small scale (OECD 2004).

In *pyrolysis*, the fuel is heated in the absence of air to produce gas, oil and char. Varying techniques produce differing proportions of oil and char. The technology is moving from the R&D to the commercialisation phase (IEA 2001).

Improving feedstock and the fuel supply chain is a further means of improving the competitiveness of bioenergy, with the main prospects relating to the development of forestry residue systems and energy crops (IEA 2003b). The shift in agricultural and soil improvement techniques required may be equivalent of another ‘green revolution’ such as that in food production experienced over the past century, and perhaps including the application of bioengineering techniques to improve plant yields. Biomass production in the oceans may have to be considered, together with the potential environmental impacts of this production (IEA 2003a).

Under the SD Visions scenario of the IEA, biomass would increase its share of TPES from 10.8% in 2000 to 12.2% in 2030 and 15.7% in 2050 (IEA 2003a).

Wind

Overview

Wind technology converts the energy available in wind to electricity or mechanical power through the use of wind turbines.

The Reference projections undertaken by the IEA (2004a) make the following observations about wind energy.

- Wind energy generated in the OECD is expected to increase by 10.3% per annum over the period 2002 to 2030, rising from 0.5% of total electricity generated to 5.3% (between 1990 and 2002 wind energy generated increased by 23.4% per annum).
- Wind energy in the rest of the world is projected to rise from a mere 0.06% of electricity generated in 2002 to 1.03% in 2030.
- For the world as a whole, the share of wind energy in electricity generated is expected to increase from 0.32% in 2002 to 2.93% in 2030.

Wind energy is rapidly increasing its share of electricity generated as cost reductions achieved through improvements effected during the 1990s combine with the exploitation of favourable sites. The cost competitiveness of wind power is expected to continue to improve over the coming decades, although prime wind-generating sites on land will have been fully utilised in many countries well before the end of the projection period. Wind is an intermittent source of energy and therefore unsuitable for meeting peak demand. Where wind is available (coastal locations are usually better than inland locations) up to 10 to 20 per cent of a region's electrical generation capacity can be supplied by wind without adverse economic or operational effects (IEA 2004a).

The Reference projections assume that land-based wind resources are fully exploited in the advanced economies by 2030. There would remain, however, considerable long-term potential for the exploitation of offshore wind power. Offshore production allows for locations with much higher wind speeds and avoids major visual impact if located sufficiently far from the coast. However, capital costs in terms of extra expenses for installation, electric cables and maintenance need to be offset by technological improvements before the potential of this resource can be fully exploited. A substantial contribution from offshore wind farms is expected by 2030 (IEA 2004a).

Nearly 90 per cent of the wind energy capacity is installed in OECD countries, with 69 per cent in OECD Europe (Germany, Denmark and Spain being most important), 19 per cent in OECD North America, and 8 per cent in South Asia. The largest increase in capacity in recent years has occurred in Germany.

In the United States, federal and state incentives encouraged the deployment of wind power in the early to mid-1980s. After an initial boom, the expiry of the incentives and a decline in fossil fuel prices slowed the trend. By the mid-1990s capacity was actually declining. However, since then, renewed interest in wind, supported by renewed tax incentives for the period 2005 to 2007, should result in significant capacity increases (Halperin 2005).

In Denmark, growth in wind power was strongly encouraged by government since 1976. Denmark subsequently developed a large wind-turbine-manufacturing industry. Danish companies hold a large share of the global wind turbine market and Denmark has the highest share of wind (some 12 per cent) in its electricity mix of any country in the world.

Germany's spectacular increase in wind capacity in recent years can be almost entirely attributed to the supported grid purchase price. This support is now being very slowly phased down. In Spain, incentives to renewable-energy producers have also encouraged strong growth in wind capacity. The development of wind power in India has been encouraged by investment-related incentives.

Land Use

Although not much land is needed for the installation of each turbine, they must be spaced several rotor diameters apart, so wind farms have extensive land requirements. Assuming an average land use factor of 0.12-0.15 km^2/GWh, 2% of Germany's total land area would be used by wind-farms if 10% of the country's current electricity demand were produced from wind turbines. Competing uses, such as agricultural crops, forestry, tourism or urban uses, may limit the sites available for wind-farm development. At the same time it should be noted that the ‘footprint’ of a wind-tower is small so that other uses could be made of most of the wind farm area including grazing as in Denmark (IEA 2001).

Environmental Issues

Wind-power generation is free of pollutants but has a number of environmental effects that may limit its potential. The most important effects on the environment are:

1. Visual effects. This is perhaps the most important and most discussed issue. Wind turbines must be in exposed areas and are therefore highly visible. They are considered unsightly by some people.
2. Noise. Wind turbines produce two different types of noise – aerodynamic noise, from air passing over the blades; and mechanical noise, from the moving parts of the turbine, especially the gearbox. Better designs have reduced noise, and research on this issue continues.
3. Electromagnetic interference. Wind turbines may scatter electromagnetic signals causing interference to communication systems. Appropriate siting away from military zones and airports can minimise this impact.
4. Bird safety. Birds get killed when they collide with the rotating blades of a turbine. Migratory species are at higher risk than resident species. Siting the turbines away from migratory routes reduces the impact.

Technology

Wind turbines convert wind power into electrical energy. The amount of energy that can be produced is directly dependent on the wind speed, more precisely on the cube of the wind speed. Turbines will not commonly operate at times of low wind speeds, and need to be shut down to avoid damage of equipment at times of very high wind speed (IEA 2005c).

The resource base is not an inherent constraint to the development of wind power. The challenge lies in delivering this potential to the markets at competitive costs. The main factors that influence the cost of electricity from wind power are capital cost, the influence of wind conditions on economics, and the influence of technology on economics.

The capital cost includes the cost of turbines, their installation and grid-connection costs. Turbine costs have declined as the size of wind turbines has increased and manufacturers have increased production volume. In addition to cost reductions, improved blade designs and control systems have enhanced turbine efficiencies, thus lowering the cost of producing a unit of power. The location of a wind farm may have a major impact on the investment cost. Wind farms located away from existing transmission lines, the need for grid-reinforcement in remote areas, and associated transmission losses are all important considerations. The issue of transmission costs may become more important in the future as the best locations near transmission lines are used first.

Locations with higher wind speeds and with winds available for longer periods produce more electricity. Wind speed increases higher above ground. Higher wind speeds can be obtained by building higher towers. Taller towers may increase capital costs, but they reduce generating costs.

The increase in turbine size has brought cost reductions per kW of installed capacity because of economies of scale. Large rotors have contributed to this trend (IEA 2001).

Despite reductions in its production costs, electricity from wind power still costs more than production from the cheapest conventional technologies in almost all circumstances. However, wind power technology is expected to go on improving and capital costs are likely to decline with larger volumes of turbines produced, and continuing gains from learning-by-using (particularly in relation to the siting of wind turbines)[6]. The trend towards building larger machines with larger rotors and taller towers is expected to continue, improving performance and reducing the unit cost of electricity. The difference between the electricity generating costs of wind and fossil fuels is expected to narrow. At the best sites, wind will become competitive with the cheapest fossil fuel resources by 2010. However, wind market growth will continue to be constrained by the technology's intermittence and by site limitations. Since the best sites will tend to be developed first, later developments will have less favourable conditions, putting a brake on eventual growth.

The wide range of sites and projects pursued in offshore wind farms make it difficult at present to generalise about offshore capital costs but it is expected that capital costs will decline over time as has been the experience of onshore wind farm developments (IEA 2005d).

The production of wind turbines has tended to concentrate in Europe, particularly Denmark and Spain. However, the United States is poised to become a significant producer with General Electric, already one of the key suppliers of conventional generating plant to the global electricity industry, entering the wind turbine market (Halperin 2005).

Offshore Wind

In the period from 1995 to 2000 a series of small demonstration projects testing the potential of offshore wind power was constructed in sheltered shallow waters in Northern Europe. From 2000 to 2004 further demonstration projects were developed that had an increasingly commercial focus and were developed in what were technically more demanding conditions. By the end of this period some 15 projects had been developed, many of them being large-scale and commercial.

Denmark was the first country to develop commercial-scale offshore wind, but although undoubtedly lessons were learned through this experience, other countries have not sought to replicate the Danish experience. Rather, development has proceeded in parallel in a number of countries, with practices in each country reflecting largely its own context, and particular early experiences. Of particular interest is the installation of wind turbines on top of oil and gas platforms in the North

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[6] Alic et al. (2003).

Sea, which reduces the cost of building a stable platform from scratch (*The Economist* 2005c).

The offshore wind industry is in a process of learning-by-doing. Consistent development of the industry is required to bring it to fully realise these learning economies. In addition, there remains a need for ongoing R&D to address the technical barriers which have come to light in the current generation of offshore wind projects and those which are anticipated in the future sites, specifically those in deeper water and requiring larger turbine sizes to generate economies of scale.

So far, the capital cost of the offshore wind farms currently developed has been at least 50% higher than onshore wind farms of comparable size. This cost differential has not been fully compensated for by an increased load factor. Moreover, offshore wind farms operate in a market regime which has developed around onshore wind. As a consequence of all this, recent offshore projects have been economically marginal in the absence of additional support mechanisms. Moreover, the delays which have been observed in the construction works for the most recent projects are unlikely to have been fully budgeted within the contract price by contractors. As a result, one could expect some upward pressure on contract prices in the near future. Moreover, operating costs are not well understood at present, particularly for projects with access difficulties. Many of the commercial risks in construction and operation that were anticipated (e.g. delays, serial turbine failures, cable failures) have materialised. The cost of insurance for construction and operation is high and rising with a significant claims history already established for offshore wind (IEA 2005d).

Grid Integration

Wind is an intermittent source of energy. Wind speeds vary on an hourly, daily, seasonal and annual basis. Wind is best suited for areas where there is a correlation between wind speed profiles and electricity demand profiles. For example, in Denmark and California wind patterns tend to match demand. But this is often not the case.

The value of wind-generated electricity to the local grid is closely tied to when it is available and how predictable this availability is. Electricity output from wind farms can increase or decrease rapidly, and such changes cannot generally be controlled by the producer. Thus, grid integration is likely to be a critical issue in the development of wind power. Intermittence and low overall capacity factors reduce wind’s value in meeting peak demand. Hence, equivalent conventional capacity or energy-storage capacity may be required, which entails extra costs.

A relatively low proportion of wind power in power generation might be acceptable, without the need to add new conventional capacity. In the near term, therefore, this issue is not likely to be a barrier to the initial development of wind power. It could become more important, however, as the share of wind in total installed capacity increases. Should this occur, wind producers would have to find ways of mitigating the higher costs resulting from intermittence. The main way to do this is by aggregation with other generators, particularly those that can follow the variations in the wind farm’s output. The intermittence is closely intertwined with network organisation. Decentralised forms of network organisation based on bilateral contracts may help to exploit wind power by shifting the intermittence issue directly to users, who are in the best position to deal with it by various market mechanisms (IEA 2001).

Interest in wind forecasting has been growing over recent years along with the recognition of technical implications of higher penetrations of wind power. For wind penetrations of below around 5%, wind forecasting is generally regarded as not being necessary because of small grid penetrations. At higher levels of penetration, the returns from improved weather forecasting become much greater. Research programs that focus on improving wind forecasting and modelling techniques are ongoing in Europe and the United States. Improved weather prediction can reduce the extra costs of wind power but it will only do if the technologies available in a given energy system are flexible.

Finally, wind turbines have very few unexpected outages when compared with traditional power plants and they also need less maintenance (IEA 2005c).

Options for Managing Intermittency

The impact of intermittency on the electricity grid can be mitigated by grid integration, geographic and technical distribution of generators, and improved weather forecasting techniques. Nevertheless, the residual unpredictability and the general variability – including periods when there is no wind available – have to be managed.

The principal tools for managing this residual intermittency are the operational and capacity reserve, responding to short- to medium-term and long-term variability respectively. Studies conducted in Germany and France indicate that the extension of wind power would not require the addition of new plants to provide operational reserve as it can be absorbed in the general fluctuation of the system.

For the future grid integration of wind power, the provision of flexible capacity reserve will become one of the key variables, reflecting the fact that even large wind capacity numbers will face climatic conditions where there is little or no wind. This is also one of the most important cost items when considering the long-term integration of wind power into electricity grids.

The six main options for managing intermittency currently discussed are:

1. Power plants providing operational and capacity reserve.
2. Electricity storage.
3. Interconnection with other grid systems.
4. Distributed generation.
5. Demand-side response.
6. Curtailment of intermittent technology.

1. Power plants providing operational and capacity reserve

This is the most frequently cited option in the literature. Using power plants for balancing services is a well-known and tested ancillary service in electricity systems. In today’s grids, it is typically met by flexible plants with relatively short response times. Depending on national circumstances, these could be open-cycle gas turbines (OCGT) but also steam-fired power plants like coal and oil running at below full capacity. Overall, in terms of commercial availability, cost competitiveness and ease of system integration, power plants are the state of the art for providing the necessary ancillary services for intermittent wind generation in most countries.

2. Storage

Hydro storage facilities, whether in the form of pumped-hydro or hydro reservoirs, have played a key role in many countries in providing several grid balancing services. Their advantages are the potential for large-scale electricity storage, fast response times and relatively low operating costs.

Beyond hydro storage there has been very little commercially available storage technology that operates on today's electricity grids. The main reasons are: (i) large-scale grid integration replaces to a certain extent the function of storage, and (ii) other storage technologies are as yet not cost competitive with reserve generator capacity. Future technological possibilities for energy storage are discussed in a later section of this paper.

3. Interconnection with other grids

One reason why the western Danish grid can handle a high proportion of wind power very well is that it has good interconnectors with the Swedish, Norwegian and German grid and thus, for example, access to Norwegian hydro power as reserve capacity. The Scandinavian 'Nord Pool' electricity market was established in 1996. The benefit for a country such as Denmark is that it can trade wind power on the spot market at times of excess supply, and if this cannot be used at the time of production elsewhere in the market it can be stored in hydropower storage facilities in Norway or Sweden. In turn, Danish operators can purchase extra electricity on the Nord Pool market at times of low wind generation.

However, the high concentration of wind power in the northern part of Germany and its proximity to the Danish part of the grid with a similarly high share of wind capacity on the system can pose threats to systems despite good interconnection to the neighbouring countries. This is due to the fact that transmission grids have not been originally developed to accommodate increasingly large amounts of wind energy and associated cross-border trade. This highlights the need for further transmission grid development, including strengthening and upgrading existing lines.

Furthermore, planning new grid capacity is a time-consuming process and building new transmissions comes with additional costs, both in terms of the original capital costs and regular ongoing costs associated with maintenance requirements. Nevertheless, interconnection of grids is seen as an important step in the development of energy systems in both Europe and North America. Major interconnection plans are currently being discussed, including the linking of the Netherlands and Norway through a sub-sea cable.

4. Distributed generation

Distributed generation (DG) is defined as 'generating plant serving a customer on-site or providing support to a distribution network, connected to the grid at distribution-level voltages'. DG can provide significant system benefits for local distribution companies by relieving congestion, reducing transmission losses and delivering ancillary services to the system. Thus, DG could provide fast and longer-term reserve requirements to the grid at a regional level as an alternative to large-scale power plants. One of the frequently cited DG options are combined heat and power plants (CHP), which produce heat much like a conventional boiler but also produce electricity at the same time. This is utilised in colder climates such as Scandinavia, for example, where electricity demand is higher in winter and load increases are typically greatest in the morning at the same time when the heat demand picks up.

However, there exist a number of barriers to a wider integration of DG into electricity grids. One important area is information exchange. Where networks are managed in a decentralised way, increased information flows are required to ensure smooth operation of the system.

5. Demand side response (DSR)

The idea behind DSR is that electricity produced at different times of the day has different values, as can be witnessed by the price differential between base and peak load power on the wholesale market. If the marginal peak load price is higher than the value that the customer gets out of the services derived from the electricity delivered at peak times, the customer would be willing to modify demand if paid the peak price or slightly less instead. A grid operator is indifferent between paying a power producer to supply more output and paying the same amount to a customer to switch his/her electric appliances instead, as both provide the identical balancing service. In principle, market mechanisms can be devised to cope with peak demand and with intermittency. DSR makes the demand curve for electricity more elastic and thus sensitive to price changes which will reduce the need for reserves in an electricity market, other things being equal.

In practice, however, contributions from DSR in many countries have so far been relatively small, with some exceptions such as Norway. It is unclear whether this is due to electricity users' marginal valuation of electricity being too high to stay on-line even at high prices, or whether there are transaction costs or informational barriers to access such a market.

6. Curtailment of wind farms

Recently, with the expansion of wind farms offshore, curtailment of intermittent technologies has become a further option to cope with system variability. Large wind farms can in principle provide the same ancillary services that conventional generators offer today. Switching off some wind turbines for operational reserve or running them at reduced output becomes a realistic option with modern large-scale wind farms. Furthermore, where transmission and distribution capacity is congested, curtailment of wind farms is an option to ensure system stability. Curtailment of wind farms has been practised in northern Germany. Wind turbine manufacturers are also investing in control technology that evens out short-term fluctuations. The flexibility offered by wind turbines can be very valuable for an electricity system as an alternative to shutting down or part-loading coal and CCG turbines implies higher energy and maintenance costs for subsequently heating them up. Therefore, tariff systems or contractual arrangements are required to ensure that wind turbine owners benefit from the system savings they can provide with a flexible operation of their turbines.

Summary of options

The resultant mix of options is likely to be different between different national grids. For example, where hydropower is available for balancing services, this is likely to be the predominant choice since it has been proven as very flexible at low prices for these services. Grids with a high proportion of gas-fired plants might be more reliant on this technology for balancing services. Greater interconnection between grids would allow for a greater availability of least-cost options on a wider geographic scale while mitigating the impact of intermittency further. On the other hand, this will probably require increased long-distance transportation of electricity with associated transmission losses and investment requirements for grid upgrades.

In any case, when choosing between the different options the trade-offs have to be visible in the market for it to develop a least-cost solution. Without differential pricing at different times of the day, storage systems and demand side responses will not be economical. To upgrade grids and increase the interconnection between them, large-scale investments are often required but at current there is often no clear regulatory incentive for those who benefit from these investments to meet a share of the costs (IEA 2005c).

Geothermal

The Resource

The technology for extracting electricity for hydrothermal resources is mature, and its use is expanding in both industrialised and developing countries. Geothermal sources all originate from thermal energy trapped beneath and within the solid crust of the Earth. Theoretically, the total accessible resource base of geothermal energy to a depth of 5 km is over 1 million TWyr, but only an infinitesimal fraction of this total could ever be captured even with advanced technology.

There are four types of geothermal sources, including hydrothermal sources (hot water and steam), hot dry rock (HDR), magma (molten rock reservoirs either very deep or in the vicinity of volcanoes) and geo-pressurised sources (hot brine usually associated with methane in pressurised water aquifers). Such occurrences within layers of the crust easily accessible by current or foreseeable drilling technology are limited.

Geothermal energy for electricity generation is cheap where it is available, but that tends to be in places that are volcanically active. The United States, Italy, Japan, New Zealand and Iceland remain the most important locations for geothermal energy in the advanced economies, and the Philippines, Mexico and Indonesia among the developing economies.

The BAU scenario of the IEA (2004a) makes the following projections for geothermal energy.

- After increasing by only 1.2% per annum during the 1990 to 2002 period, geothermal energy generated in the OECD is expected to increase at 3.5% per annum from 2000 to 2030, its share of total electricity generated rising from 0.34% in 2002 to 0.65% in 2030.
- Geothermal energy generated in the rest of the world is expected to increase by 3.9% per annum from 2002 to 2030, taking its share of total electricity generated form 0.38% to 0.43%.
- For the world as a whole, the share of geothermal energy in electricity and heat generated is projected to increase from 0.35% in 2002 to 0.53% in 2030.

Limited growth for geothermal electricity is projected in the next decade because the paucity of suitable sites in the advanced economies limits potential development (IEA 2004b). The big potential for growth exists in the developing economies. In the longer run, tapping lower temperature sources of energy by pumping water into subterranean hot dry rocks may become a useful source of renewable energy with a wider range of sources than conventional geothermal energy (Day 2004). IEA (2005e) suggests that it is possible with the full exploitation of opportunities that geothermal energy could supply 5% of global electricity by 2020. Installed geothermal power has doubled between 2000 and 2005.

Development

The IEA Implementing Agreement for Cooperation in Geothermal Research and Technology (GIA) came into effect in 1997 with an initial operating period of five years. It has subsequently been extended to 2007. The objective of the GIA is to advance and support the use of geothermal energy on a worldwide scale by overcoming barrier to its development. The summaries of the GIA Annexes are given below.

1. Environmental impacts of geothermal energy development. The activities cover:

- investigation of the impacts of development on natural features;
- study of the problems associated with discharge and reinjection of geothermal fluids;
- Examination of methods of impact mitigation and production of an environmental manual; and
- Examine the potential of induced seismic events in conjunction with reservoir development or subsequent extraction of heat from underground.

2. Enhanced geothermal systems (EGS). The objective is to investigate new and improved technologies that can be used to artificially stimulate a geothermal resource to allow commercial heat extraction. Fieldwork is being undertaken in the European Project Soultz and the Australian Cooper Basin projects. The work is divided into four sub-tasks:

- to review the use of conventional and new geothermal technology to enhanced geothermal system technology;

- to collect information necessary for decision making, design and the realisation of a commercial EGS energy production plant;
- to review and evaluate geochemical modelling techniques for determining reservoir characteristics; and
- to conduct field studies of EGS reservoir development and performance.

3. Deep geothermal resources. The objective is to address the issues associated with the commercial development of geothermal resources at depths greater than about 3000m. Deep geothermal wells have been drilled in Australia’s Cooper Basin, and Bad Urach in Germany. The activities have been divided into three sub-tasks:

- research on exploration technologies and reservoir engineering for deep, hot reservoirs;
- investigation into drilling and logging techniques; and
- exchange of information and establishment of a database on fluid chemistry, material properties and corrosion issues, together with field testing.

4. Geothermal power generation cycles. The objective is to develop scenarios as a basis for comparison of cycles, plant performance and availability, economics and environmental impact and mitigation. Work has yet to begin following the drafting of an action plan.
5. Advanced geothermal drilling techniques. The investigation is divided into three sub-tasks:

- the compilation of a database on geothermal well drilling cost and performance;
- production of a geothermal drilling best practices handbook; and
- monitoring and exchange of information on drilling technology development and new applications.

6. Direct use of geothermal energy. The emphasis is on improving implementation of the technology, reducing costs and enhancing use. Geothermal energy can be used directly for such applications as building heating, industrial process heating, and temperature control for farming, swimming and bathing, etc.
7. Geothermal market acceleration. Here are large untapped resources in many countries. This program aims to hasten geothermal development by identifying regions with unexploited potential, collating resource assessments on a few sites and discussing with key players the barriers to progress in their regions (IEA 2005e).

Geothermal Hot Dry Rock

Hot dry rock (HDR) is a heated geological formation usually composed of granites at depths of 3 to 5 kilometres. This enormous energy resource can be tapped by introducing water to a specially prepared HDR reservoir and extracting it as high-pressure steam to run conventional steam turbine power equipment.

Under certain conditions, subsurface granites can reach 250^0C and higher to depths of 3 to 5 kilometres. These granites are hot for a number of reasons. They are relatively high in decaying radioactive elements, and heat is conducted from very hot resources below. In most cases (and preferably), the granites are buried beneath thick insulating sedimentary rocks. The aim of a hot dry rock program is to harness the energy in these granites by injecting water into a borehole and circulating it through a permeable reservoir created by hydraulically fracturing pre-existing, minute cracks in the rock. Success primarily depends on the presence of these natural fractures. The injected water is superheated as it passes through the hot rocks and returned to the surface via adjacent boreholes, where it is converted to carbon-free generated electricity using conventional steam turbine technology. Extending the reservoirs and adding more boreholes can increase power output.

HDR technology is at the experimental stage; there are no commercial schemes anywhere in the world. Nevertheless the resource has potential in the very long term. Given the scale of the engineering required, this technology is likely to be most appropriate for grid connected applications.

Although overseas HDR programs have not been successful to date, it is considered that geological and related conditions in Australia are infinitely more favourable than those encountered in HDR projects in the USA, Europe and Japan. A study funded by the Australian Government and completed in 1994 found that Australia has extensive HDR resources with the potential to generate electricity many times its current total annual electric power needs. A large area of the Cooper Basin in the south-west corner of Queensland and the north-east corner of South Australia has been identified as containing the largest and most promising HDR sites for creation of reservoirs that would make it possible to extract commercial quantities of energy (IEA 2005e).

Another possible site is in the Hunter Valley where the first tenement in Australia for the right to extract heat from hot dry rock was granted in 1999. Analysis of the initial research results suggested that a geothermal anomaly exists in the form of buried granite at a depth of at least 5km. The granite appears to represent a substantial source of energy, capable of providing base-load generation. This resource is well located to tap into the electricity grid for Eastern Australia. A new company, Geodynamics Pty Ltd was floated in 2002 to develop the geothermal resources in both the Hunter Valley and the Cooper Basin.

Solar Energy: Photovoltaics

Technology and Applications

Photovoltaic (PV) technology transforms the energy of solar photons into direct electric current using semiconductor materials. The basic unit is a photovoltaic or solar cell. When photons enter the cell, electrons in the semiconductor material are freed, generating direct electric current. Solar cells are made from a variety of materials and come in different designs. The most important PV cell technologies are crystalline silicon and thin films, including amorphous silicon.

PV cells connected together and sealed with an encapsulant form a PV module or panel. When greater amounts of electricity are required, a number of PV modules can be connected together to form an array. The components needed to transform the output of a PV module into useful electricity are called 'balance of system' (BOS). BOS elements can include inverters (which convert direct current to alternate current), batteries and battery charge controllers, direct electric current switchgear and array support structures depending on the use.

A PV cell converts only a portion of the sunlight it receives into electric energy. This fraction is the efficiency of the PV. Laboratory research has recently achieved efficiencies of 32%. In practice, efficiencies are lower.

Currently, photovoltaics have the highest level of costs of all commercially deployed renewable energy sources, reflecting high capital costs. The spread of costs between regions is also high given the substantial variation in insolation (the amount of sunshine). Most current photovoltaic power is decentralised in buildings and this is expected to remain its main use throughout the projection period. It is in attractive option in areas of abundant sunshine and high electricity prices, and may play a useful role in meeting peak consumption associated with the use of air conditioning systems. In remote areas it can also be a cost-effective option.

The applications of photovoltaic technology directly linked with electricity production are outlined below.

Stand-alone (off-grid) systems. Using stand-alone photovoltaic systems can be less expensive than extending power lines and more cost-effective than other types of independent generation. Most of currently profitable applications are remote telecommunications systems, where reliability and low maintenance are the principal requirements. PVs also have wide application in developing countries, serving the substantial rural populations who do not otherwise have access to basic energy services. PVs can be used to provide electricity for a variety of applications in households, community lighting, small enterprises, agriculture, healthcare and water supply.

Grid-connected systems in buildings. When more electricity than the PV system is generating is required, the need is automatically met by power from the grid. The owner of a grid-connected PV system may sell excess electricity production. Net metering rules can promote this. Buildings are a large potential market for grid-connected photovoltaic systems. Substantial reductions in capital costs will be necessary to make this technology commercially viable. The competitiveness of PV electricity in buildings depends, with technology given, on the price of electricity that the owner of the PV cell would otherwise have to pay to a local electricity supplier. Uncertainty over future electricity prices could be an important barrier to the development of PV markets, although it can also be a stimulus in regions that lack generating capacity. Over the past few years electricity prices to final consumers in the OECD area have tended to decline. If electricity prices increase in the future, PVs will become more competitive. Recognition of the environmental benefits of renewable energy may encourage some consumers to invest in PVs, despite the higher costs. This is likely to be one of the main drivers of market growth over the next twenty years.

Utility-scale systems. Large-scale photovoltaic power plants consisting of many PV arrays installed together can provide bulk electricity. Utilities can build PV plants faster than conventional power plants and can expand the size of the plant as demand increases. Only a small percentage of current PV capacity has been installed by utilities. It is unlikely that PV technology for utility-scale generation will become competitive over the next twenty years. Even if it did so, utilities are likely still to prefer to meet peak load with dispatchable devices with very low capital costs, such as gas turbines (IEA 2003b).

Current and Prospective Trends

Installed PV capacity has increased fivefold between 1992 and 1999. Nearly half the total PV capacity is used in off-grid application. This share is particularly high in Mexico, Australia and the United States. On-grid applications are mostly distributed (in buildings), while centralised PV production accounts for less than 7% of total PV capacity.

Japan has the highest PV capacity (452 MWp in 2001). This is a result of the 'Residential PV System Dissemination Program' which provides investment subsidies to individuals, real estate developers and local organisations involved in public housing projects. Japan has the ambitious objective of reaching 5000 MW of installed capacity by 2010, and increase by a factor of more than 10, requiring annual capacity additions of 436 MWp over the next ten years.

The United States had a PV capacity of 213 MWp in 2001. The most important initiative related to PV development is the Million Solar Roofs Program, which aims at installing solar energy systems on one million US buildings by 2010. This effort included two types of solar technology – photovoltaics that produce electricity from sunlight and solar thermal panels that produce heat for domestic hot water, space heating or swimming pools.

In Germany, there was 195 MWp of installed capacity in 2001. The 100,000 Roofs Solar Power Program provides low interest loans for 10 years. In addition to central government support, 10 of Germany's 16 federal states support PV through various incentives. The aim of the 100,000 roofs program is to reach a total installed capacity of 300 MWp in 2003. The 'Renewable Energy Promotion Law' set an attractive buy-back tariff for PV-generated electricity.

The other main countries with significant installed PV capacity in 2001 were Australia (34MWp), the Netherlands (21), Italy (20), Switzerland (17), Spain (16) Mexico (14) and France (12) (IEA 2003b).

Over the next twenty years, the use of PV technology is likely to expand, but its contribution to the global electricity mix will remain relatively small. On the other hand, PV may be the best technology to meet energy needs in remote areas and for building applications. Capital costs are expected to decline as demand for PV increases and larger quantities are produced. Most of the reductions are expected to be in PV module costs, rather than in the cost of BOS. The timing and rate of future cost reductions are uncertain.

IEA (2004a) makes the following projections for total solar energy (photovoltaics and thermal)

- Solar energy will contribute 0.75% of electricity generated in the OECD in 2030 compared with a mere 0.01% in 2002.
- In the rest of the world, the contribution of solar energy to electricity generated would rise from less than 0.01% in 2002 to 0.07% in 2030
- For the world as a whole, solar energy's contribution would rise from 0.01% to 0.38% in the period considered.

The longer run potential of solar energy in electricity generated could be very considerable. Energy required for buildings contributes 11% of greenhouse gas emissions in the advanced economies. If the potential of solar energy to meet the needs of buildings were fully harnessed in grid-connected systems, the figure of 6% could be a feasible target for solar energy in the very long run.

Natural Cycles

Photovoltaic cells convert sunlight directly into electric energy. The amount of energy that can be produced is directly dependent on the intensity of available sunshine and the angle at which solar PV cells are radiated. PV cells are still capable of producing electricity even in temperate winter conditions and even during cloudy weather, albeit at a reduced rate. Natural cycles in the context of PV cells thus have three dimensions:

- a seasonal variation in potential electricity production with a peak in summer (although in principle PV cells operating along the equator have an almost constant exploitable potential throughout the year);
- diurnal variation from dawn to dusk peaking at mid-day; and
- short-term fluctuation of weather conditions, including clouds and rainfall, impact on inter-hourly amounts of electricity that can be harvested.

Short-term fluctuations are reduced by geographically distributed PV production.

Technology

Cost reduction has been a key issue for *solar photovoltaics*, as costs are still relatively high compared to other types of grid-connected electric technologies. But cost reductions achieved in commercial applications have been impressive. Cost reduction opportunities for cells and modules are of prime importance because these items are expensive components of photovoltaic systems. Research and development is especially important for new cell technologies to enter the manufacturing sector and markets. To bring new concept cells and modules into production, new manufacturing techniques and large investment is needed. Scale economies are also important in reducing module costs. Novel concepts for PV can be found in a variety of scientific fields including nanotechnology, organic thin films and molecular chemistry. Fundamental research is needed to demonstrate the technical feasibility of advanced solar photo-conversion technologies which use the energy of sunlight to produce fuels, materials, chemicals and electricity directly from renewable sources such as water, carbon dioxide and nitrogen.

Better integration of PV technologies into building architecture would also assist the spread of solar energy in electricity and heat production. Innovations are occurring in such areas as modular rooftop PV systems, the development of a solar PV rooftop tile and solar PV wall panels.

Solar Thermal

Overview

The economics of solar thermal power can be expected to gradually improve over the projection period but is unlikely to be competitive on a significant scale by 2030 except in areas with high insolation. Solar thermal technologies are suitable for large-scale electricity generation (IEA 2004a).

Concentrated solar power, which provided a mere 0.02% of electricity operating capacity in the OECD in 2001, is targeted by the IEA Global Market Initiative for Concentrated Solar Power to reach 0.19% of global electricity operating capacity by 2020.

Electricity Production

Solar-thermal technologies concentrate solar radiation onto a receiver, where it is converted into thermal energy. This energy is then converted into electricity. There are a number of technology options available, although they are at different stages of deployment. The most important technologies are the parabolic trough, the central receiver and the parabolic dish. Parabolic trough is commercially available and is the least expensive solar-thermal technology. The other two technologies are at the demonstration stage. They have, however, the potential to achieve higher conversion efficiencies and lower capital costs than parabolic-trough technology (IEA 2003b).

Solar-thermal technologies can be combined with fossil-fuel or thermal-storage technologies to provide firm peaking to intermediate load power. They take up a lot of space, currently 20m^2/kW. Their water requirements are similar to those of a fossil-fuel steam plant. Water availability could be an important issue in arid areas, which are otherwise best suited to solar thermal plants. Considerable interest is now developing in solar thermal electricity in a hybridised configuration, where use can be made of steam cycle equipment already in place, such as in existing thermal power stations. Hybridisation of up to 25 per cent in a coal-fired boiler facilitates reliability, enhanced conversion efficiency and increased capacity.

The Global Market Initiative for Concentrated Solar Power (CSP) is to help create the conditions conducive for new plants and to expedite the building of 5000 MW of CSP worldwide over the next ten years through international collaborative efforts.

No significant commercial plants have been built since the last solar thermal plant in Southern California plant in 1990. The withdrawal of the incentives that enabled these plants to be constructed and operated (with private capital) left no incentives for CSP technology in the OECD or developing economies.

Since that time, developers and researchers have been busy improving the various components of the technology not only in solar research institutions but also importantly in the field, making use of the Californian plants themselves. Projects have commenced in the United States (Arizona, Nevada), Australia, Italy, and Spain. Scoping studies for projects are under way in Algeria, India, Iran, Israel, Jordan, Portugal and South Africa.

The main messages from the cost projection studies undertaken by the IEA are the following.

- The technology has the potential to be cost competitive before 2030 and will then be one major electrical power option for developing countries, which are often located in the sunniest parts of the world. Due to the possibility of hybridisation and thermal energy storage solar thermal power is dispatchable power that helps to support grid stability, as opposed to many other renewable energy sources.
- The current portfolio of research projects will not be sufficient to reduce CSP costs down to a competitive level. Additional streams of research will be required (IEA 2005f).

Heat Production

The market for solar-thermal heating systems took off in the 1970s as a result of high oil prices. Low oil prices in the 1980s reversed the trend and many solar-thermal companies went bankrupt. Improvements, both in technology and in efficiency, have led to a recent resurgence of the industry in many countries.

Solar hot-water heaters use the sun to heat either water or a heat-transfer fluid in collectors. A typical system will reduce the need for conventional water heating by about two-thirds. Individual water heaters are the most common application for solar thermal energy. Other uses of solar thermal energy include space heating and solar cooking. These are of limited significance currently.

The main barrier to implementing solar thermal energy on a large scale is cost, particularly the high up-front cost of equipment to collect and store solar energy. As in the case with most forms of renewable energy, environmental benefits are not reflected in costs and so they appear more expensive than conventional fuels. Solar thermal heating, however, produces no emissions during operation, although small levels of emissions are associated with the manufacture and installation of components and systems. Other barriers include the need for large collecting areas for large amounts of energy and intermittence (IEA 2001).

The Implementing Agreement for a programme to Develop and Test Solar Heating and Cooling Systems (SH&C IA) is increasing the level of collaboration with industry. The current research tasks of the SH&C IA include:

- performance of solar power components;

- sustainable solar housing;
- solar crop drying;
- day-lighting in buildings in the 21st century;
- advanced storage concepts for solar and low energy buildings;
- solar heat for industrial processes;
- testing and validation of building energy simulation tools; and
- PV/thermal systems (IEA 2005a).

Ocean Energy

Introduction

Ocean energy comprises a diverse range of technologies. They include tidal energy, wave energy, energy from marine currents, ocean thermal energy (OTEC), and energy from tapping the salt gradient.

Ocean energy systems are largely at the research and development and pre-commercial stage of technology development (ETC). Over the next 25 years, wave power could increase significantly in importance from its current very low base, but would still remain a very minor source of energy. Ocean thermal energy may not be commercialised until after 2030.

IEA (2004a) makes the following projections for ocean energy.

- In the OECD electricity generated from ocean energy could increase by 14.1% per annum between 2002 and 2030, lifting it from 0.01% of total electricity generated to 0.24%.[7]
- In the rest of the world, ocean energy may remain of negligible importance and for the world as a whole it might increase from less than 0.01% of electricity generated in 2002 to 0.11% in 2030.

A major challenge to developers and those supporting development in this area is that a number of different resource types exist for ocean energy systems (including waves, tides, tidal currents, salinity and thermal differentials). In addition, there are several different ways of extracting the energy from each resource type. Comparisons between systems is challenging due to the differing underlying assumptions of power production, generator capacity and cost statements (IEA 2005a).

The Implementing Agreement for Ocean Energy Systems (Ocean IA) was created in June 2001. The review of national activities on wave and marine current energy carried out within this Agreement has revealed that R&D on wave energy and marine current energy continued in 19 countries. The exploitation of these renewable ocean resources will see a new industry emerging and new opportunities for existing

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[7] In the longer run its potential contribution to electricity generated could rise to over 2%.

industries, such as offshore engineering and construction, shipbuilding, turbines, hydraulic and electrical equipment (IEA 2005g).

Tidal Energy

Tidal power utilises the oscillatory flow of water in and out of partly enclosed basins along coastlines with sufficient tidal flow. Water then flows back and forth through a number of reversible hydro turbines located in dams across the entrances of the tidal basins. Several possible sites around the world have been evaluated. They occur in the United Kingdom, France, Canada, Australia, South-eastern China, India, South Korea, Argentina, Chile, and the former USSR. However, many of these sites are remote from centres of demand, which will impede their development.

The first and largest plant is the 240 MW plant built for commercial production across the La Rance estuary in France between 1961 and 1967. It has now completed more than 30 years of successful operation. In 1984 the Canadians began operating an 18 MW plant on the coast of the Bay of Fundy. It was originally intended to be the forerunner of much larger projects in the upper Bay of Fundy but these have not materialised. Other tidal plants include the 400 kW experimental unit built in 1968 on the Barents Sea in Russia, and the 3.4 MW Jianxia station built in China between 1980 and 1986.

Tidal power incurs relatively high capital costs, and construction times can be several years for larger projects. In addition, the operation is intermittent with a relatively low load factor (22-35%). Thus, although plant life can be very long (120 years for the barrage structure and 40 years for the equipment), the high capital costs and long construction time have deterred the construction of large tidal schemes.

Wave Energy

Wave energy results from energy transmitted from wind to ocean surface. Ocean waves can travel long distances before reaching coastlines and releasing their energy. There are several companies internationally developing technologies to capture this energy for conversion into electricity. Existing wave power systems can either be a floating device connected to the seabed, or shore mounted devices. Coasts with exposure to the prevailing wind direction and long fetches tend to have the most energetic wave climates. This embraces the western coasts of the Americas, Europe and Australia and New Zealand.

The total annual European deepwater resource amounts to about 320 GW (estimated capacity requirements 1159 in 2030). The conversion of the resource could supply a substantial part of the electrical energy demand in countries such as Ireland and Portugal, and the whole electrical energy demand in isolated islands and remote areas. Currently, only two wave power installations are operated as commercial-testing installations.

The large number of different concepts under investigation at present in various parts of the world suggests that the best technology has not yet been identified. Prototypes of just a few concepts have been tested at sea, and the first power plants claiming commercial viability have recently been or are being built. Three types of wave energy devices have been considered: shoreline devices, bottom-fixed near-shore devices and offshore devices.

Several full-scale prototypes of shoreline and nearshore devices have been tested in the sea since 1985. They include projects in Scotland, Norway, the Azores islands (Portugal), Australia, Japan, in South China and India. Another two prototypes have been built near-shore (second generation). The second generation incorporated into the harbour of Sakata on the NW coast of Japan has been operating without major maintenance requirements since 1990.

Offshore third generation devices are in general more complex technologically and in addition require moorings and long electrical cable connection to land. On the other hand, they are less dependent on environmental constraints and exploit the more energetic deep-water resource. They are more appropriate for the large-scale exploitation of wave energy. The first offshore wave energy prototype, The Mighty Whale, was launched in 1998 in the bay of Tokyo and tested until 2002. In 2003 the first two third generation gird-connected wave energy devices were deployed. They are the 1:4.5-scaled model of the Wave Dragon being tested in the Baltic Sea and the 750 kW Pelamis prototype whose tests in the Marine Energy Centre got under way in 2004. Another system deployed in 2004 off Portugal (a 2 MW device).

Unlike the case of wind energy, the present situation shows a wide variety of wave energy systems, at several stages of development, competing against each other, without it being clear which types will be the final winners.

In the last ten years or so most of the R&D activity in wave energy has been taking place in Europe, largely due to the financial support and coordination provided by the European Commission and to the positive attitude adopted by some European national governments.

In general, the development, from concept to commercial stage, has been found to be a difficult, slow and expensive process. Although substantial progress has been achieved in the theoretical and numerical modelling of wave energy converters and of their energy conversion chain, model testing in wave basins is a time-consuming and expensive task is still essential. The final stage is testing under real sea conditions. In almost every system, optimal wave energy absorption involves some kind of resonance, which implies that the geometry and size of the structure are linked to wavelength. For these reasons, if pilot plants are to be tested in the open sea, they must be full-size structures. For the same reasons, it is difficult, in the wave energy technology, to follow what was done in the wind turbine industry: the development of relatively small machines and the subsequent scaling up to larger sizes and powers as the market developed. The high costs of constructing, deploying, maintaining and testing large prototypes under sometimes very harsh conditions, has hindered the development of wave energy systems; in most cases such operations were possible only with substantial financial support from governments.

Marine Currents

Kinetic energy from the sea can be harnessed using relatively conventional techniques, which are similar in principle to those for extracting energy from the wind, by using submarine converter similar to underwater windmills. This option is still relatively undeveloped. A number of studies have been completed on the energy potential of marine currents but there have been few on the engineering requirements for utilisation of this resource. Countries where theoretical studies and experimental projects took place are the United Kingdom, Italy, Japan, Canada, Australia, Russia and China in addition to the European Union.

Studies to assess the marine currents resource have been conducted in the European Union and in East Asia. In Europe this resource is of special interest for the United Kingdom, Ireland, Greece, France and Italy. In this area 106 promising locations were identified and it was estimated that, using present day technology, these sites could supply 48TWh/yr to the European electrical grid network. In China it has been estimated that 7000 MW of tidal current energy are available. Locations with high potential have also been identified in the Philippines, Japan, Australia, Northern Africa and South America.

The first two prototypes are being developed in Italy and the United Kingdom with the support of the European Commission.

Ocean Thermal Energy (OTEC)

Ocean thermal energy conversion makes use of the naturally occurring temperature difference between warm water on the surface and cold water at depths of about 1000m. The minimum difference in temperature is usually about 20^{O}C. Such differences are found in tropical and sub-tropical areas. This form of energy is costly and is not likely to be widely commercialised by 2020. Oil dependant tropical islands are potentially the most viable sites for this technology.

It is well known that power can be generated from two sources of heat at different temperatures. The idea of using the cold deep water of the ocean as the cold reservoir of a thermal engine whose hot reservoir is the warm surface water was proposed as early as 1881. Several prototypes were developed by French, American and Japanese teams and were tested in Cuba, Brazil, Hawaii and Japan until the mid-1980s. Although OTEC operating principles are well documented and no scientific or technical breakthroughs of great magnitude are required, the schemes tested so far have posed complex engineering and cost problems, and no prototype of industrial size has been built yet (IEA 2005g).

Tapping the Salt Gradient

The mixing of salt and fresh water in estuaries is another way to tap solar energy. Membranes separating the two fluids create different partial pressures that could be used for power generation. The low efficiency of the process may in part be offset by the large resource potential. Differences in the salinity of water are an integral part of solar ponds. The salt gradient creates zones of different heat trapping potentials that can be utilised in analogy to the OTEC process (*Energy* 1993).

Salt gradient devices are at a much lower level of development and much research and development is required to assess its eventual commercial possibilities (IEA 2001). Salinity gradient systems need to overcome several hurdles. The main difficulty is the development of functioning and efficient membranes able to generate sufficient energy to make an energy system competitive. The complementary development needed is system integration into a power generation plant (IEA 2005g).

Energy Storage

Overview

Two of the most promising forms of renewable energy are wind power and solar energy. However, these sources of energy are intermittent in character. As a result, if a large proportion of energy is generated from wind and solar sources, there is a need for substantial reserve capacity that would be underused during wind and solar operating hours. Of course, if the electricity grid is fed from numerous small local power stations spread across a broad range of climatic regions, and the overall power system is integrated, these sources of renewable energy will collectively have a more stable supply profile than is the case where they are drawn only from specific regions. Moreover, hydropower and bioenergy can be used as renewable forms of reserve capacity.

Yet in the long run, technologies for storing solar and wind energy would greatly assist the long-term potential of these forms of energy. The spectrum of potentially useful storage technologies ranges from electrochemical, electrostatic and electromechanical to thermal and chemical media.

Types of Energy Storage

The commonest form of *electrochemical* battery is the lead-acid battery, which is now largely a mature technology. They are cost-effective and highly efficient, but have a low energy density, and their disposal causes considerable problems. Among a range of new battery technologies, the most promising for energy storage are lithium ion or lithium polymer batteries, which take the form of a thin film. The technology is still very new, and the costs correspondingly high. But efficiency and energy density are high, weight is negligible, and the batteries are good for innumerable cycles, environmentally sound and require virtually no maintenance. Lithium ion batteries also do not need special chargers. They make particular sense for photovoltaics because the batteries can be built into the panels, thereby integrating generation and storage in one unit. Building roofs and façades would also be suitable storage surfaces.

The second form of energy storage is *electrostatic*. Supercapacitors are the chief example. Electricity is stored without loss in a solid electrolyte, and no chemical change takes place. Supercapacitors are light and can be extremely small. Though still immature, the technology combines high energy density and efficiency with low environmental impact. Their working lifetime is greater than for all other battery types. The cost, though, is still high, and current models are not very powerful, having been developed for lower-power electronics – wristwatches, mini-radios and measuring instruments.

Flywheels are an important example of electromechanical storage. Fly-wheel technology has a variety of applications from cassette recorders to motorbikes, including motor generators. Years of neglect have left the technology underdeveloped, but energy densities are high and there is no waste disposal problem. Researchers are currently experimenting with magnetic fields as a means of achieving higher speeds and reducing the loss of stored energy due to friction caused by the weight of the spinning mass. Flywheels are easy to manage and can be scaled down, which makes them suitable for local autonomous supplies, to bridge gaps in supply from wind or PV.

Compressed air, another form of electromechanical storage, is a tried and tested technology that can be quickly deployed for electricity storage. Electrical energy drives air compressors which pump air into high-pressure tanks. The stored air is then used to drive generators or motors as required. Compressed air could find a future application for energy storage in buildings.

The power storage that offers the widest variety of applications *is electrolytic extraction of hydrogen*, by which electrical energy is converted into chemical energy. Electrolysis is a long-established process; the primary focus of development work is improved efficiency. The overwhelming majority of schemes for hydrogen production from renewable energy envisage using large power stations – such as large dams or solar thermal plants – to mass-produce hydrogen for subsequent delivery to the end-user. The other option for solar-powered hydrogen electrolysis would be a locally based approach, using electricity from PV or wind.

The question of how better storage options can ensure or further develop energy self-sufficiency is also germane to *solar heating*. So far, solar heating provides only one part of the necessary heat, with additional heating needs being met from conventional sources. The next step is to seek complete independence from fossil fuel top-up supplies. The technological solution to this problem lies in a larger collector area, greater storage capacity, and the reduction of heat needs through better insulation, heat exchangers, heat reclamation and optimal passive solar gain for the building as a whole. Another option is the solar magnesium hybrid storage system developed in Germany. The system works by using mirrors to concentrate heat on the storage unit, where the heat energy separates hydrogen from magnesium. The hydrogen can then be used as a heat-transport medium to drive a Stirling engine[8] producing electricity and hot water for the heating system. Once the hydrogen has recombined with the magnesium, the cycle can begin again. Stirling engines could also be used to enhance the efficiency of cogeneration systems (Scheer 2002).

Economics

The challenge for all storage technologies is cost reduction. The major needs in R&D are developing new electro-catalysts, new electrode materials and new structural materials for electrochemical systems; magnetic bearings, better fail-safe designs and lightweight containment, and composite rotors with higher specific-energy for flywheels; better corrosion-resistant materials for batteries with higher power density; commercial high-temperature superconductors (operating at liquid nitrogen temperatures) for superconducting magnetic energy systems; higher energy-density

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[8] Stirling engines are thermal power plants which do not need a fixed fuel input, being able to convert any external heat source into mechanical or electrical energy.

ultracapacitors for light-duty vehicles; and improved power conditioning systems (IEA 2000).

Fuel Cells

Description

Fuel cells are electrochemical devices that convert the energy of a chemical reaction directly into electricity, with heat as a by-product. They are similar in principle to primary batteries except that the fuel and oxidant are stored externally, enabling them to continue operating as long as fuel and oxidant (oxygen) are supplied. [9]

Each cell consists of an electrolyte sandwiched between two electrodes. Fuel is oxidised at the anode, liberating electrons which flow via an external circuit to the cathode. The circuit is completed by a flow of ions across the electrolyte that separates the fuel and oxidant streams. Practical cells typically generate a voltage of around 0.7-0.8 volts and power outputs of a few tens or hundreds of watts. Cells are assembled in modules known as stacks and connected electrically in both series and parallel to provide a larger voltage and output.

The other main components of a fuel cell system are a fuel processor and a power conditioner. The fuel processor converts fuels such s natural gas, methanol, gasoline or bio-ethanol into the hydrogen-rich fuel required by the fuel stack.

Fuel cells are usually classified by their electrolyte. Phosphoric acid fuel cells (PAFCs) represent the first generation of commercial fuel cells. 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 cogeneration, and around 37-42% for electricity production alone. However, they are larger and heavier than other fuel cells with equivalent power output. They are also expensive, at around US$400-4500/kW, because they require an expensive platinum catalyst. The development of this technology has enabled subsequent development of other fuel cells and of the needed infrastructure for fuel-cell technology.

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. Their current disadvantages are that they require cooling of the cell to prevent overheating, they use an expensive platinum catalyst which is extremely sensitive to CO poisoning. The RD&D effort is focussed on (i) new platinum/ruthenium catalysts that are more resistant to CO, and (ii) new types of membrane materials that will be less prone to poisoning and avoid the need for cooling systems.

Molten carbonate fuel cells (MCFCs) are being developed to be fuelled by natural gas and are primarily focussed on distributed or centralised power-generation applications. They cannot be fuelled by pure hydrogen. MCFCs use a molten-

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[9] The references for this sub-section of the paper are IEA (2004d) and IEA (2005h).

carbonate-salt electrolyte suspended in a porous, inert ceramic mix. They do not use precious-metal catalysts, which reduces their costs compared with many other types of fuel cells. MCFCs can achieve energy efficiencies of 60% and close to 90% if used in cogeneration. Their resistance to poisoning is being improved. Efforts are also being made to extend their economic life, which is limited by their high operating temperature and electrolyte-induced corrosion.

Solid oxide fuel cells (SOFCs) use a non-porous ceramic electrolyte and appear to be the most promising 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. Precious-metal catalysts are unnecessary, which reduces costs. These advantages are balanced by cell design problems and a slow start-up capability as a consequence of the high operating temperature required. The development of low-cost materials with a high durability represents an important goal for RD&D.

Alkaline fuel cells (AFC) were the first fuel cell technology ever developed and were used in the United States' space program. They use a potassium hydroxide solution as the electrolyte and a variety of non-precious metals as a catalyst to the anode and cathode. 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 (as is required with motor vehicles), as they need pure oxygen. Their commercial use is therefore constrained by costly purification processes and their short lifetime.

Other types of fuel cells include the following:

1. Polymer electrolyte fuel cells (PEFC) - fuel cell vehicles and stationary power.
2. Direct methanol fuel cells (DMFC) - cellular phones and computers.
3. Direct ethanol fuel cells (DEFC) – fuel cell vehicles.
4. Hydrogen membrane fuel cell (HMFC) – fuel cell vehicles.

Development Status

The production of fuel cells in 2003 amounted to 2800 systems, of which 800-900 were stationary fuel cell units with a capacity greater than 0.5kW, 1600-1800 were portable fuel cells 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 US$338 million.

PEMFCs are the technology of choice for the transportation sector and also represent 70-80% of the current small-scale stationary fuel cell market. SOFCs represent 15-20% of the stationary market at the moment, but their share is projected to increase gradually. PAFCs dominated the large-scale stationary market until 2002, but MCFCs are expected to take most of this market in the period 2005-2015, along with a gradually increasing share of SOFCs (IEA 2005h).

Stationary fuel cells (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%. SOFCs and MCFCs seem better suited to residential CHP 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 4500 hours. The current research goal is for stationary applications to have a lifetime of 40,000 to 60,000 hours, or 5-8 years of operation. 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 stack also determines the life of the fuel cell system.

The fuel cells due to be introduced in the period up to 2010 could have a large impact on energy use and emissions in the following decade and beyond. Fuel cells are much more efficient than competing technologies in most applications leading to major GHG emission savings. A fully sustainable energy system can be envisaged for the longer term, where the fuel is a biofuel or hydrogen produced from electrolysis using a renewable energy source. In the very long term, fuel cells could be a key component of any hydrogen economy (IEA 2004c).

Emissions Reduction Potential

The technology of fuel cells, by directly converting chemical energy into electric energy, can attain higher yields than is the case for thermally-generated electricity. They also have other advantages – silent functioning, small emissions of pollutants, a great variety of usable fuels (natural gas, propane, butane, naphtha, methanol, carbonic oxide gas, hydrogen, gasified coal, biomass or landfill gas), relatively small size, good performance in partial charging, modular construction, short manufacturing time, quick replacement, and economic maintenance (due to the small number of moveable parts).

Barriers to Wider Use

Cost is likely to be the major barrier to wide use of fuel cells for stationary generation. Production costs, even for fuel cells approaching market readiness, are high, making them less competitive with established technologies. A key issue is that fuel cell stacks are still not suited to mass production techniques. In addition, current technologies continue to employ significant quantities of expensive catalyst obtained from noble metals. There are also technical barriers associated with individual fuel cells. For example, the sensitivity of fuel-cell performance to impurities in the fuel stream is an important research topic for applications with coal, biomass or waste as their primary fuel.

Other potential barriers include the provision of fuel infrastructures, safety and regulatory issues and lack of awareness of the technology. The introduction of new fuel infrastructures would be a major issue for methanol or hydrogen vehicles. Most of the regulatory issues for mobile and stationary systems are only just starting to be addressed and there are no specific safety concerns with fuel cells, although there may be problems of public perception with hydrogen-fuelled systems. A PAFC demonstration project in Hamburg has successfully addressed both public perception and regulatory issues, and a hydrogen fuelled fuel cell system has been installed next to a school. Lack of awareness by potential users is another barrier that is reducing as a result of ongoing demonstration and dissemination activities (IEA 2004c).

In the BAU Scenario, almost all the fuel cells in use by 2030 will be for distributed power generation, and then mainly to alleviate draw from the grid rather than replace it. Accelerated technological progress may make it possible for fuel cells to become competitive for base load power generation in CHP applications by this time (IEA 2005h).

Research, Development and Commercialisation

In the past, research activities were mainly undertaken by Government organisations and research laboratories but now they are increasingly led by car makers and power engineering companies who recognise the potential threats and opportunities offered by fuel cells. Global partnerships have developed, typified by the collaboration between DaimlerChrysler, Ford, Ballard Power Systems and Shell. Collaboration is very important because no one company or country will have the resources necessary to commercialise fuel cell technology on its own.

Future demonstration and commercialisation activities will require the close involvement of potential customers for fuel cell systems and other relevant organizations such as fuel supply companies, local authorities, transport planners and legislators.

Public funding is still very important to the fledgling fuel cell industry because it allows industry to develop longer-term technologies with significant technical and commercial risks, and it helps to encourage the development of an industrial base. Major providers of public-sourced funds are the US Department of Energy, NEDO in Japan, and the European Commission (IEA 2004c).

Japan arguably leads the world in fuel cell technology development. The current research focuses on the commercialisation of PEMFC for transportation applications and as sources for embedded generation for domestic and office buildings. The United States is focusing on the development of reliable, low-cost, high-performance fuel cell system components for transportation and buildings applications (IEA 2005h).

The IEA Advanced Fuel Cells Implementing Agreement (IEA FC) is pursuing research programs on several types of fuel cells (PEFC, SOFC and MCFC). In addition, it has a program specifically aimed at the use of fuel cells for stationary applications. Its initial results suggest that market conditions vary widely between different IEA countries because of climatic variations (which affects the operation of CHP) and differences in fuel and electricity prices. Potentially attractive niche markets have been identified for uninterruptible power supply and small stand-alone systems, while single house applications have limited prospects except in remote locations. Fuel cell installations for bigger buildings serving several households can be more favourable as the demand changes will be levelled out and the running hours longer. The medium sized fuel cells operating in large buildings and in industries have a large potential market, as soon as they are commercial at competitive price levels.

Conclusions

Fuel cells offer the same benefits of higher efficiency and lower emissions to developing markets for transport and power generation. However, they are likely to be applied in the developed world first, as early models will require local technical support and maintenance. Once developed, fuel cells could be very attractive to developing countries as they have few moving parts and are therefore potentially very reliable. Power generation applications may be limited by the availability of pipeline natural gas although fuel cell systems could be adapted to run on LPG, coal or biofuels. There may also be niche applications for fuel cells running on waste hydrogen from refineries and chemical industries (IEA 2004c).

Hydrogen

Background

Hydrogen is a carbon-free energy carrier that has potential uses in many applications. For example, it can fuel vehicles, provide process heat for industrial processes, supply domestic heating needs through cogeneration or heat recovery systems, and fuel power plants for centralised or distributed generation.

Hydrogen as an energy carrier can be used to power fuel cells. These cells are a promising technology as a source of electricity and heat for buildings, and as a power source for electric vehicles. The fuel-cell units currently in operation are generally natural gas-fired, but research efforts are also being directed at the integration of other fuel sources, such as gasified coal, with fuel-cell plant (IEA 2001).

The source flexibility of hydrogen and electricity on the one hand, and the storability of hydrogen and the synergism between the electron and proton carriers on the other, make hydrogen the ideal load-balancing fuel for primary energy sources with intermittent availability. It appears that the development of a hydrogen supply infrastructure will be an inevitable prerequisite for the large-scale utilisation of many renewable forms of electricity. For example, the prospects for a rapid market penetration of photovoltaic electricity beyond the level of local or incremental importance hinge on the removal of the electricity storage barrier. Hydrogen represents an immediate solution to electricity storage (*Energy* 1993).

Some analysts believe that hydrogen will be the basic form of energy that will provide power to future societies, replacing natural gas, oil, coal and electricity (note Rifkin, 2002). Such a vision is for the very long-term. However, the commercial deployment of some hydrogen technologies, such as fuel cells, is likely to begin soon, although significant market penetration is not expected before 2015-2020.

Hydrogen and fuel cells have emerged as one of the most highly funded technology areas of research in IEA countries. Multi-year government budget allocations have been earmarked in the United States, the European Union and Japan. Large programs are also in place in other countries such as Canada, Germany and Italy. IEA countries as a whole are devoting something like US$1 billion each year to government-funded hydrogen and fuel cells programs. More than half of this is earmarked for fuel cells, however, including non-hydrogen varieties. Meanwhile, it is estimated that the private sector's own widespread activities are absorbing a massive US$3-4 billion. Stakeholders include oil, gas and coal companies, process gas producers, power plant manufacturers, electric power utilities, motor manufacturers, producers of fuel cells, chemicals and high-tech companies.

A very wide diversity is observed in national R&D programs, which range from fully-integrated, public-funded efforts to national strategies bringing together both public- and private-sector initiative. Long-term programs, coupled with international initiatives, are ensuring long-term commitment (IEA 2005b).

Hydrogen Production

Introduction

Hydrogen can be produced from a variety of feedstocks. These range from fossil resources such as natural gas and coal to renewable resources such as biomass and water with input from renewable energy sources (e.g. sunlight, wind, wave or hydro-power). A variety of process technologies can be used, including chemical, biological, electrolytic, photolytic and thermo-chemical. Each technology is in a different stage of development, and each offers unique opportunities, benefits and challenges. Local availability of feedstock, maturity of technology, market applications and demand, policy issues and costs will influence the choice and timing of the various options for hydrogen production.[10]

Hydrogen from Fossil Fuels

Hydrogen can be produced from most fossil fuels. The complexity of the processes varies. Since carbon dioxide is produced as a by-product, the CO_2 should be captured to ensure a sustainable (zero-emission) process. The feasibility of the processes will vary with respect to a centralised or distributed production plant. Although the cost of such plants is high in comparison with conventional coal-powered plants, they have the potential to produce electricity and hydrogen efficiently, and to allow CO_2 separation and capture.

Production from Natural Gas

Hydrogen can currently be produced from natural gas using three alternative chemical processes.

- Steam reforming. In this process methane reacts with water vapour at high temperatures to produce hydrogen and carbon monoxide, with the latter being converted into carbon dioxide and hydrogen through the water-gas shift reaction.
- Partial oxidation. Here, methane reacts with oxygen to produce hydrogen and carbon monoxide, with the latter further reacting to steam to produce additional hydrogen and carbon dioxide.
- Autothermal reforming. This is a balanced combination of steam reforming and partial oxidation.

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[10] This sub-section draws heavily on Riis and Hagen (2005) as well as IEA (2005h).

For moderate levels of hydrogen demand with a low geographic 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 carbon capture and storage form 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.

Production from Coal

Hydrogen can be produced from coal through a variety of gasification process, such as fixed bed, fluidised bed or entrained flow This process is commercially mature, but is more complex compared to the production of hydrogen from natural gas. The cost of hydrogen is also higher, but in the very long run the abundance of coal resources increase its significance as an energy source relative to scarce natural gas. The costliness of the process results in part from the need to use pure oxygen for the reaction. The production of such 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. Other developments that may reduce the cost of hydrogen from coal gasification include new hydrogen membrane reactors that reduce the energy needs for gas separation.

The production of hydrogen by coal gasification is not suited to decentralised production because it relies on economies of scale, and the capture and storage of carbon dioxide in small-scale systems would be expensive and difficult. However, the large-scale production of hydrogen from IGCC plants appears to be an 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 separation of carbon dioxide for carbon sequestration systems. 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.

Other Production Processes from Fossil Fuels

Hydrogen is also produced from fossil fuels in petroleum 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. Petroleum refineries need hydrogen to process crude oil and to improve the characteristics of transportation fuels. The refinery industry’s demand for hydrogen is increasing due to: (1) the increased processing of heavier crude types, (2) the continued shift of the product mix towards the more hydrogen-rich transportation fuels, and (3) the reduction of sulphur levels in motor transport fuels. As a consequence of these trends, refineries will be growing consumers of hydrogen and cannot be considered as 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 increased recovery of hydrogen from coke oven gas has limited prospects as it reduces the net CO_2 benefits of hydrogen use substantially (IEA 2005h). The electrolytic production of chlorine from salt produces hydrogen as a by-product. 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 fuel cell-vehicles, it could become more attractive to use this hydrogen in fuel-cell vehicles in the future.

Capture and Storage of CO_2

Carbon dioxide is a major exhaust in all production of hydrogen from fossil fuels. The amount of CO_2 will vary with respect to the hydrogen content of the feedstock. To obtain a sustainable (zero emission) production of hydrogen the CO_2 should be captured and stored. Because of the need to capture CO_2 for an energy conversion process of relatively low efficiency, and then using the electricity to electrolyse water, the overall efficiency of fuel to hydrogen would be not more than 30%.

Electrolysis

Electrolysis is a well-known process that converts water into hydrogen and oxygen using electricity. Currently, two types of electrolysers exist: the alkaline electrolysers , and the less mature polymer electrolyte membrane (PEM) technology. Alkaline electrolysis is a mature technology that is well suited to producing hydrogen for stationary applications. The major R&D challenges for alkaline electrolysers is to improve their efficiency, lifetime and costs. PEM electrolysers are basically fuel cells operated in reverse mode. In PEM electrolysis, the electrolyte is a solid, acidic membrane and no liquid electrolyte is required. Major advantages include the absence of a corrosive electrolyte, a compact design, high current densities and high operation pressures. 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, efficiency and lifetime) can be improved by new materials and new cell stack design.

Electrolysis makes possible the production of hydrogen using alternative sources of energy. But electrolysis requires substantial amounts of electricity. Moreover the environmental friendliness of the technology depends on using either alternative energy sources or fossil fuels supported by carbon capture and storage as means of producing the electricity required. Currently, electrolysis provides only a small percentage of the world’s hydrogen, most of which is supplied to industrial applications requiring small volumes of high purity hydrogen. It will also be decades before improvements in renewable energy technologies would yield electricity at a price which would enable hydrogen to compete with conventional forms of energy.

Industrial electrolysis systems currently have net system efficiencies of up to 70-75%. Current R&D efforts are aimed at improving net system efficiencies toward 85%. As electricity costs are the main operating cost of electrolysers, the main RD%D target is to increase their electrical efficiency. High-temperature and high-pressure electrolysis may offer efficiency advantages, and this may be facilitated by new developments in PEM electrolysers.

Large-scale renewable energy production is an essential precondition for the credible deployment of a sustainable hydrogen economy. At the same time, hydrogen technologies provide important services to a renewable energy systems such as back-up power for intermittent energy sources, and an energy storage mechanism for peak-shaving and load-levelling energy services. Centralised electrolysis systems appear to have both higher efficiency and lower capital costs that decentralised systems.

While centralised large-scale electrolysis appears to be the best form of production in the long run, in the transition phase when refuelling networks might be too scattered to encourage further uptake when only a small share of the vehicle stock will be fuelled by hydrogen, the decentralised production of hydrogen has advantages. There are four systems that have been considered for the decentralised production of hydrogen: alkaline, PEM fuel cells, high temperature and high-pressure systems. These systems could operate in both continuous mode and diurnal mode, the latter using off-peak electricity (IEA 2005h).

Hydrogen From Splitting Water

Hydrogen can be produced from splitting water through various processes. Those discussed are water electrolysis, photo-electrolysis, photo-biological production and high temperature water decomposition.

Water Electrolysis

Water electrolysis is the process where water is split into hydrogen and oxygen through the application of electrical energy. A high-temperature electrolysis process might be favoured when high temperature heat is available as waste heat from other processes. There are economies to be gained from large, as opposed to small, plants, continuous production, and the use of off-peak energy.

Photo-electrolysis (Photolysis)

Photovoltaic systems coupled to electrolysers are commercially available. The systems offer some flexibility, as the output can be electricity from PV cells or hydrogen from the electrolyser. Direct photo-electrolysis represents an advanced alternative to a PV/electrolysis system by combining both processes in a single apparatus. Photo-electrolysis of water is the process whereby light is used to directly split water into hydrogen and oxygen. Such systems offer great potential for cost reduction of electrolytic hydrogen compared with traditional two-step technologies.

The key challenges to advance PEC cell innovation toward the market are achieving progress in material science and engineering. The development of highly efficient (for performance), corrosion-resistant (for longevity) photo-electrode materials and their processing technologies are most important, paving the path toward smart system integration as well as engineering. Since no ideal photo-electrode exists for water splitting exists commercially, tailored materials have to be engineered. Research needs to concentrate on material screening for desirable properties and subsequent engineering of system solutions.

Photo-biological production (Biophotolysis)

Hydrogen can be derived from organic matter and water using micro-algal photo-synthesis. Photo-biological production of hydrogen is based on two steps, photosynthesis and hydrogen production catalysed by hydrogenases in, for example, green algae and cyanobacteria. Significant research is needed to understand the natural processes and genetic engineering of hydrogen production in large bio-rectors. An alternative approach consists of reproducing a two-step reaction suing artificial photosynthesis, a technology which at present exists only in laboratory-scale projects.

High Temperature Decomposition

The direct use of high-temperature heat to split water and produce hydrogen has the advantage of avoiding the costly ad energy-consuming generation of electricity as an intermediate step. The main problem is that direct water splitting occurs at very high temperatures (above 2500^0C). At this temperature 10% of the water is decomposed and the remaining 90% can be recycled. To reduce the temperature other processes for high temperature splitting of water have been suggested:

- thermo-chemical cycles;
- hybrid systems coupling thermal decomposition and electrolytic decomposition;
- direct catalytic decomposition of water with separation with a ceramic membrane (‘thermo-physic cycle’); and
- plasma-chemical decomposition of water in a double stage CO_2 cycle.

For these processes efficiencies of over 50% can be expected and this could possibly lead to a major decrease of hydrogen production costs. The main technical issues for these high temperature processes are materials development due to the need for corrosion resistance at high temperatures, high temperature membrane and separation processes, heat exchangers, and heat storage medium development. Generally speaking, design aspects, safety issues, and coupling issues with heat sources are important and new matters for high temperature processes.

At this stage only thermo-chemical water splitting can be considered as an option for eventual commercialisation as the alternative technologies are at a very early stage of RD&D. A significant number of thermally-driven chemical cycles have been proposed for thermo-chemical water splitting. While such technologies are technically feasible from a chemical point of view, low cost and high efficiency processes that are commercially viable have yet to be developed. The sulphur-iodine cycle appears to be the most promising as it can achieve higher efficiencies and use chemicals that re 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. The cost of such a system is considerably lower than that of a solar PV-based system, but is twice the cost of hydrogen from coal and natural gas with CO_2 capture, and from the nuclear cycle. The current state of development of thermo-chemical technologies to produce hydrogen suggests that commercially viable plants can be expected from 2030 onwards (IEA 2005h).

Biomass to Hydrogen

In biomass conversion processes a hydrogen containing gas is normally produced similar to the gasification of coal. Biological processes are generally much slower and more costly than thermo-chemical processes. They are unlikely to play a role in the centralised production of hydrogen, mainly because large-scale plants would need a big supply of biomass which increases the transport costs considerably. Moreover, the production of hydrogen from biomass is in potential competition with biofuels production for biomass supplies. Biofuels have the 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.

So far, no commercial plants exist to produce hydrogen from biomass. Currently, the pathways followed are steam gasification (direct or indirect), entrained flow gasification, application of thermo-chemical cycles, or the conversion of intermediates (such as ethanol, bio-oil or torrified wood). None of the concepts have reached a demonstration phase for hydrogen production.

Centralised Hydrogen Production

Large-scale, industrial hydrogen production from all fossil energy sources can be considered a commercial technology for industrial purposes, though not yet for utilities. Hydrogen production at a large scale has the potential for relatively low unit costs, although the hydrogen production cost from natural gas in medium sized plants may be reduced towards the cost of large-scale production. An important challenge is to decarbonise the hydrogen production. CO_2 capture and storage options are not fully technically and commercially proven and require R&D on absorption and separation processes and process line-up, and acceptance of CO_2 storage. It is also important to increase the plant efficiency, reduce the capital costs and enhance the reliability and operating flexibility.

Further R&D is particularly needed on hydrogen purification, to produce hydrogen suitable for fuel cells, and on gas separation, for the separation of hydrogen or carbon dioxide from gas mixtures. This involves the development of catalysts, adsorption materials and gas separation membranes for the production and purification of hydrogen. Hydrogen and power can be co-produced in a combined cycle in an integrated gasification and combined cycle (IGCC) plant. The IGCC plant is the most advanced and efficient solution where the carbon in the fuel is removed, and hydrogen is produced in a pre-combustion process.

An important challenge for centralised hydrogen production is the requirement for large market demand and the construction of a new infrastructure for hydrogen transmission and distribution and CO_2-pipeline to storage.

In the future, centralised hydrogen production from high temperature processes based on renewable energy and waste heat can also be an option for enhancing sustainability and removing the need for capture and storage of CO_2.

Distributed Hydrogen Production

Distributed hydrogen production can be based on both water electrolysis and the natural gas processes discussed above. The benefit would be a reduced need for transportation of hydrogen fuel, and hence a smaller need for hydrogen infrastructure.

Distributed production will also utilise existing infrastructure such as water and electric power or natural gas. However, the production costs for smaller capacities will be higher, and the efficiencies of the production will probably be lower than for centralised plants. In addition, carbon capture and storage would be more difficult and costly for small fossil-fuelled plants, and there might be safety issues for public use. Also, it is unlikely that CO_2 from fossil fuels will be captured and stored when hydrogen is produced from distributed reformers.

Small-scale reformers will enable the use of existing natural gas pipelines for production of hydrogen at the site of the consumer. Such reformers will represent an important technology for the transition to large hydrogen supply. The availability of commercial reformers is limited and most reformers are currently at an R&D stage.

Further development of R&D is essential to meet the customer requirements. In deriving hydrogen from natural gas, specific areas of R&D required are focussing on hydrogen gas quality and minimising emissions. With regard to both hydrogen form water electrolysis and form natural gas, R&D needs include:

- reducing cost;
- maximising compactness;
- developing user friendly, atomised plants;
- improving the reliability and durability of operation;
- optimising the service, training and maintenance program;
- developing safety, standards and certification; and
- increasing the system energy efficiency.

The technology achievements in the last three years have been remarkable and the technology gaps have been significantly reduced. But some of the remaining gaps are challenging and will require more effort by the technology developers and suppliers. Compactness is especially important for distributed hydrogen production. Also, codes and standards for hydrogen production and storage will need to be revised to permit the use of enclosed or underground spaces, at least in some countries.

Research and Development

The main focus of current research on new supply technologies is on hydrogen production and use. The amount of carbon and other emissions from hydrogen-based energy will depend on how the hydrogen is produced. Fossil fuels (particularly natural gas for large scale production and methanol for road vehicles) may provide the initial source of energy for producing hydrogen for use in fuel cells. Much later, depending on how technology advances, hydrogen production may be based on electrolysis of water using nuclear or renewable energy. In that case, net carbon emissions could be negligible. However, this method of producing hydrogen may be costly from the energy point of view and if practiced on a large scale would use significant amounts of water, which may not be available everywhere. Other options, such as natural gas steam-reforming using high temperature solar or nuclear heat are not fully developed yet, although they could drastically reduce associated carbon dioxide emissions at a low cost.

In a fast technology world, other ways to produce hydrogen, using biological agents (microbes) might also be developed. However, efficient ways to concentrate it, to increase its energy density, and to store it for fairly long periods (days or months) would be needed. Technological developments in this area would benefit from research and rapid process in materials science and basic chemistry, aided by continuous improvement in the knowledge of how living organisms manufacture at molecular level materials possessing special properties (IEA 2003a).

Hydrogen Storage

Large-scale Hydrogen Storage

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 exist: depleted gas fields, salt mine caverns and hardrock mine caverns. Investment costs arise in relation to the underground cavern or aquifer cost and the wells required for injecting the hydrogen. The energy required for compressing the energy for storage less the energy recovered when the gas re-expands on recovery is estimated at 2.1% of the energy content (IEA 2005h).

Transportation and Distribution of Hydrogen

There appear to be two broad approaches to the transportation and distribution of hydrogen:

1. Small-scale local hydrogen production based on either electrolysis or gas reformation, thereby utilising existing electricity or gas distribution infrastructure.
2. Large-scale dedicated hydrogen production infrastructure, including pipelines and/or road transport.

The first option has a number of attractions from the viewpoint of minimising distribution costs, although it could make it more difficult to achieve the economies of scale associated with large-scale hydrogen production and to capture and store CO_2 when hydrogen is produced out of fossil fuels. It also requires augmentation of both gas and electricity production and distribution infrastructure. And if renewable energy becomes the key means for hydrogen produced from electrolysis, there would be the cost of integrating renewable energy into the electricity grid system.

Pipelines have been used to transport hydrogen for more than 50 years. Current hydrogen delivery infrastructure exists only for limited industrial hydrogen markets for chemical and refining industries in Europe and the United States. Those limited systems lack the scope or scale needed to deliver hydrogen outside of these few industrial areas to potential large-volume end-user applications. Therefore, it is likely that significant capital investment in dedicated hydrogen delivery infrastructure will be required before a hydrogen economy can be realised. The investment cost for hydrogen pipelines is about six times higher than for natural gas. This is because a larger pipe diameter is required to supply the same amount of energy. In addition, more expensive materials are needed.

Alternative approaches include using the existing natural gas delivery infrastructure. These systems, however, would require significant modification for use in the delivery and distribution of hydrogen. For example, modification would be required to allow for the fact that hydrogen has physical properties that may cause degradation of some high-strength steel piping materials and components (such as compressors and valves) currently used by natural gas.

The evaluation of options also includes the use of an alternative liquid fuel as consideration for a hydrogen carrier, such as hydrogen-rich liquid fuels (e.g., coal-derived methanol and Fischer-Tropsch liquids). Analysis is also needed to evaluate the trade-offs that exist between the use of existing liquid fuel and natural gas infrastructure to deliver hydrogen-rich fuels and the massive capital investments required for implementing a system with central hydrogen plants, associated pipelines, and distribution centres in a dedicated hydrogen infrastructure.

The transportation of hydrogen by truck requires the liquefaction of hydrogen, and this is a very expensive process. Transportation of liquid hydrogen by ship over long distances is also very expensive due to the very low temperature and the low density of liquid hydrogen. Fast ships are required in order to reduce boil-off losses (IEA 2005h).

In any case, an efficient transportation and distribution of hydrogen from the production site to the end-user is needed for the widespread use of fuel cells envisioned for the hydrogen economy. The major areas of R&D needed for improving the hydrogen transportation and distribution infrastructure include:

- high pressure gaseous storage and supporting technologies;
- hydrogen pipelines based on the natural gas pipeline industry;
- hydrogen compressors;
- compressed gas tube trailers;
- cyrogenic tankers for the bulk-transport of hydrogen in liquid form;
- hydrogen bulk storage systems and bulk dispatch terminals; and
- fuelling stations and supporting technologies (IEA 2004d).

Integrated Systems

There is a diverse range of existing and proposed integrated hydrogen systems. These systems include units to generate, store and convert hydrogen at the point of use, and will play an important role in a transition to sustainable, distributed energy systems.[11]

The challenge in the development of integrated hydrogen systems is to identify an optimum combination of existing and evolving technologies to satisfy three

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[11] The reference on integrated systems is IEA (2004f).

fundamental criteria: increased efficiency, minimal environmental impacts, and improved economics.

Many small and large-scale hydrogen systems are being developed and operated worldwide. The systems vary in the choice of power source, intermediary components, end-use and emissions profiles. The projects evaluated or under review have been located in the following countries: Germany, France, Italy, Switzerland, Norway, Iceland, Finland, Spain, Greece, The United States, Canada, Japan. Energy sources utilised include grid electricity, natural gas, biomass, hydro, wind, geothermal and photovoltaics. Production is via electrolysis or reforming. Storage is in the following forms: gaseous, liquefied, reformer, or metal hydride. The end uses are fuel cells, transport, metal hydrides, heating, domestic appliances, compressors, refrigeration units and telecommunications.

Simulation of hydrogen systems allows for a standardised assessment and comparison of costs, system efficiency, and environmental impacts. It also provides a framework for design formulation and evaluation. Some 27 unique component models have been developed. Eight are for production (PV-electrolysis; wind-electrolysis; grid-electrolysis; steam methane reforming; indirect and direct biomass gasification; biomass pyrolysis, and coal gasification). Five are for storage (compressed gas, metal hydrides, liquefaction, chemical storage, and chemical hydrides). Five are for transport and distribution (transport tanker; pipeline, low and high-pressure; tank transport; and methanol transport). Nine are for end-use and refuelling (PEM fuel cell, phosphoric acid fuel cell, solid oxide fuel cell, molten carbonate fuel cell, gas turbine, internal combustion engine, and refuelling stations – gas/gas, liquid/gas, liquid/liquid). The component list can be expanded as new techniques and technologies become available.

The centralised hydrogen energy system necessitates distribution infrastructure. Material resources flow into a centralised hydrogen production facility. The hydrogen is then stored in whatever form is decided, distribute to end-use location and/or refuelling facilities, and finally used to produce service energy with water and heat as by-products.

The distributed hydrogen energy system has small-scale distributed production, co-located storage and end-use to provide service energy, with water and heat by-products being re-used in distributed production.

A mature hydrogen energy economy will be characterised by a variety of hydrogen system configurations that fall within the scope of the generic hydrogen system model. The design and operation of systems will vary in location, scale and mode of operation, depending on access to essential natural and labour resources, technological requirements of the system, component and operational costs ad service energy requirements. In the immediate case, the implementation of hydrogen energy systems will be most likely in remote locations where the costs of fuel distribution and electricity infrastructure are relatively high, and/or environmental sustainability and conservation demands are high. Indeed, both economic and environmental imperatives are key drivers for the construction of hydrogen systems in such places as Antarctica (wind-based), Hawaii (PV-based) and Iceland (geothermal based).

Markets and Economics

Introduction

In its role as a chemical feedstock in chemical plants and oil refineries, the hydrogen market is already firmly established and viable. However, the current focus lies in its potential as a broadly distributed energy carrier. It is in this wider consumer application that significant barriers remain to the establishment of a sustainable market.

The cost differences between hydrogen and its current competitors do not favour the short-term introduction of hydrogen as a distributed energy carrier, except in some specific cases where fuel delivery costs or environmental remediation costs are prohibitively expensive. Therefore, the emphasis lies on medium-term (5 to 15 years) and long-term (beyond 15 years) cost projections in economic forecasts.

Demands for energy efficiency improvements, and cost reductions, via waste reductions, across the energy sector are important drivers for the advancement of hydrogen. Another important motivation stems from the perceived economic and political risks associated with continued reliance on subsidised and imported fuels. Finally, the development of a clean hydrogen industry is actively supported as possibly the only practical alternative to the existing fossil fuel base of global economic activity. These significant externalities can potentially offset the high capital costs of evolving technology to an appreciable extent.

Market Development

The existing and potential hydrogen market sectors can be grouped into three main categories. A distinction was made between hydrogen’s role in the energy field, which was divided into ‘direct’ and ‘indirect’ categories, and its role in other applications (the ‘non-energy’ sector).

In the non-energy sector, hydrogen was, and still is, primarily used as a feedstock for the production of chemicals or merely as a chemical commodity for other non-energy applications. This category was historically dominated by the synthesis of ammonia, predominantly for the production of fertilisers, and by methanol production. Hydrogen has also found an increasing role as a versatile reducing, cleaning, cooling and synthesis agent in the metallurgy, micro-electronics, glass, power and food processing industries. However, the average annual growth of hydrogen utilisation was clearly dominated by growth in the fertiliser market.

In the energy-direct sector, hydrogen, pure or in mixtures, has been used directly as an energy carrier. Applications have been considered for:

- mixing natural gas with small amounts of hydrogen for pollution control in space and process heating;
- the utilisation of hydrogen in ground and air transportation (mostly space exploration);
- the power generation industry; and
- portable devices.

The space industry has so far been the dominant energy-direct user.

The energy-indirect sector covered the utilisation of hydrogen as a feedstock fro the production or upgrading of other energy carriers. This includes the production of substitute natural gas, methanol and synthetic gasoline, the use of hydrogen in hydro-cracking and hydro-desulphurisation processes in petroleum refining, and the use of hydrogen in electricity production, mainly for generator cooling. This sector was expected to remain largely captive in the majority of cases. But it was predicted that a growing fraction of gaseous hydrogen will be transported by pipeline networks to regional chemical industry users, and to demonstration fuel cell operators. This sector was expected to develop into the largest of the three sectors defined, and to dominate the majority of total hydrogen demand in ensuing years. In 1978, it represented 30% of total demand and was predicted to represent 69% by 2025, showing an annual average growth from 1985-2025 of between 8.4% and 9.2%.

Total hydrogen demand in the participating countries was estimated to increase roughly by a factor of 12-17 between 1985 and 2025, representing an average annual growth of about 7%. The energy direct sector was expected to show growth of 8.4% -10% in this period, the energy indirect sector 8.4%-9.2%, and the non-energy sector 3% -3.6%. By 2025, the break-up by sector would be 16% direct energy, 69% indirect energy, and 15% non-energy. The average percentage of primary energy to be used in the production of hydrogen as an energy carrier (the direct energy sector) was expected to increase from about 2% in 2005 to about 5% in 2025.

Hydrogen Economics

Hydrogen produced from coal was the least expensive route throughout the period considered. Cost estimates lay within ±25% of the mean world prices. Other conclusions were the following.

3. Solid oxide electrolysis based on the high-temperature reactor technologies would be able to compete with coal gasification by 2025.
4. Nuclear-based technologies in 2025 would be on average 75% more expensive than hydrogen produced from coal. Different load factors and electricity prices resulted in a cost range of ±50% about the mean.
5. Hydrogen production based on biomass and partial oxidation of residual fuel oil lay between the estimated costs of hydrogen from coal and nuclear energy.
6. Cost of producing hydrogen from electrolysis of water was predominantly dependent on the electricity price. Unless the electricity is available from a low-cost, large-scale renewable source such as hydro-power or tidal-power, electrolytic hydrogen production costs will remain higher than those based on the processing of fossil fuels.

Conclusions

The most prominent hurdles relate to the cost of producing and storing CO_2-neutral hydrogen. Similarly, the cost and durability of fuel cells are still obstacles, and facilities for on-board storage of hydrogen in fuel celled powered vehicles must be improved to lengthen vehicle autonomy. Mass production and the resulting acquisition of cost-cutting technology learning will be required, along with continued development and, hopefully, breakthroughs on materials technology for both hydrogen storage and fuel cells. Cost-effective CO_2 capture and storage technologies for extracting hydrogen from fossil fuels will be needed, at least as bridging technologies in a transitional period.

A big increase in R&D is needed on biological, thermochemical and electrochemical processes for producing hydrogen. Research is also needed on hydrogen storage technologies such as that based on innovative materials – for example, carbon fibres and structures and metal hydrides (IEA 2000). Finally, major investments are required in the development of the hydrogen supply system. In the longer term a hydrogen pipeline system is likely to be the best option. Pipeline transport of hydrogen involves relatively high pressures and may necessitate the use of special materials (IEA 2003b).

Analysis should deal with systems integration, with quantifying infrastructure cost and with identifying niche markets. On international codes and standards, the findings of this work reiterate the call for harmonisation to facilitate international trade in hydrogen and fuel cell technologies.

An Overview of Alternative Energy Technologies

Near-Term Technologies

Because electricity systems are built around costly long-lived capital investments, the physical infrastructure that generates and distributes most electricity will almost certainly be much the same in ten years as it is today (Morgan 2005). Nevertheless, decisions made on this time scale based on current state-of-the art technologies will be important for the following reasons:

- Decisions on the technologies to replace obsolete plant or provide for market expansion will commit the electricity system to many decades of carbon emissions.
- In rapidly growing developing economies these technology decisions will be very important in terms of even short-term trends in emissions.
- Opportunities exist over this time horizon for the retrofit of some existing plant.
- The widespread adoption of carbon taxes and emissions trading would provide a considerable impetus to the adoption of low-emission technologies both for new infrastructure and in the modification of old technology.

The most important near-term technologies for reducing emissions from electricity production and distribution are cross-cutting technologies mainly associated with based on current technologies such as hydropower and nuclear energy. Of the newer alternative technologies, the best immediate prospect is onshore wind energy. Second in quantitative significance is biomass, with energy crops and municipal solid waste being the main sources. Solar photovoltaics are a niche prospect at present, being mainly relevant for distributed energy and remote area power.

Medium- Term Technologies

The list of medium--term alternative energy technologies that are capable of reducing GHG emissions is very extensive indeed. It includes:

- nuclear technologies – new plant designs, lower construction costs, improving safety systems;
- advanced hydropower systems;
- advanced biomass systems;
- offshore wind energy;
- advanced geothermal energy technologies including geothermal hot sdry rock;
- advanced solar photovoltaics;
- concentrated solar power;
- wave energy;
- energy from marine currents;
- advanced energy storage;
- improved technologies for the production of hydrogen by electrolysis; and
- Integrated hydrogen systems.

Long-Term Technologies

A number of alternative energy technologies offer scope for reducing emissions in the very long term. They include:

- nuclear – storage systems, safety of nuclear materials against misappropriation, fusion technology;
- tapping the ocean salt-gradient; and
- new methods of producing hydrogen.

A ZET System

There are three broad possibilities for ZET electricity generation, two of which are based on alternative energy. They are:

1. Renewable energy systems:
    1. Wind, solar and hydro (hydro balancing the intermittency of wind and solar);
    2. Solar thermal, geothermal and ocean energy (less intermittent, solar thermal, capable of base power); and
    3. Biomass systems.
2. Nuclear energy.
3. ZET non-renewable energy systems – carbon capture and sequestration.

Coping With Diverse Geographies

Given the uneven global distribution of natural resources, technological diversity provides the maximum global reach for improvements in the sustainability of the energy sector. This is particularly evident in energy production. There is a fairly limited role for international trade in electricity, so that the technologies employed in particular countries for electricity generation will be determined by a set of technologies permitted by local factors. Globally, the range of technologies employed in electricity production must be capable of meeting the diverse requirements of particular countries.

There are many location-specific factors associated with the use of renewable energy in electricity generation. For example, *hydro* electricity requires stable sources of riverine water that can be captured and utilised. Some countries have these resources in abundance (Norway, Laos), others do not possess them at all (Netherlands, Saudi Arabia). It is note economic to transport *biomass* feedstock for power generation over long distances, so only countries possessing abundant areas for agriculture and forestry can use this resource. Sites suitable for *wind* power are usually sited in coastal locations with strong prevailing winds (contrast Denmark with Austria, or Chile with Paraguay). Prospective sites for *geothermal* power have hitherto been confined to only a few countries, although the new technologies for exploiting this resource may add sites in a number of other countries with underlying hot dry rocks. *Solar photovoltaic* power could be widely used for residential and commercial sites in the future, although it will have its greatest impact in countries with sunny climates. *Concentrating solar power* will be confined to sunny climates. *Ocean energy systems* will obviously be a resource for coastal areas.

3. An Alternative Energy Technology System

The Diffusion of Emission-Reducing Technologies

Inducements to Diffusion

A number of new technologies are available on a commercial basis for diffusion through the alternative energy sector. They include biomass (particularly from sugar), onshore wind energy, and in small niche markets, solar photovoltaics. Higher fossil fuel prices also represent an inducement to diffusion. A further inducement to adopt these technologies is the anticipation that future directions of the energy sector will be particularly encouraging to renewable energy – for example, further problems with the availability or cost of fossil fuels, the introduction of carbon taxes and/or emissions trading regimes).

Constraints

There are three major constraints on the diffusion of emission-reducing technologies in the alternative energy sector. Firstly, uncertainty about future developments in energy markets, future regulation of energy markets, and future policies towards renewables, encourages a deferment of decisions to adopt new technologies.

Second, there is popular resistance to the adoption of some technologies. This mainly affects the take-up of nuclear energy and wind energy. Safety and security issues are foremost in the popular aversion to nuclear technology. Local resistance to wind energy is centred on the visual impact of wind farms and the issue of noise. Environmental problems associated with the siting of wind energy in some locations centres on bird safety and electromagnetic interference.

Thirdly, low capital stock turnover in power plants entrenches existing technologies and implies that at any one time there is a relatively small proportion of the total market for new technologies to compete in. In some cases, however, there is an opportunity for alternative technologies to be used in the retrofit of old power plants.

Induced Innovation in Specific Fields

Inducements

There are three main inducements to innovation in specific fields of alternative energy. First, high fossil fuel prices and the introduction of carbon taxes are factors that would encourage induced innovation. We are already seeing this occurring in relation to new nuclear technologies, and offshore wind technologies, biomass for energy and waste-to-energy schemes are other beneficiaries of higher fossil fuel energy prices.

Secondly, the current rate of growth in markets for certain alternative technologies promises larger, and more rapidly growing, markets for new technologies, thereby facilitating a reduction in prospective costs over time. This is encouraging to innovation in many areas of renewables technology, including photovoltaics, wind and biomass.

Thirdly, the technological opportunities for innovation in new alternative energy technologies are good. Examples include nuclear power, biomass and waste energy projects, offshore wind technologies, geothermal energy, solar photovoltaics, energy storage technologies, fuel cells and hydrogen.

Constraints

The main constraints on innovation in specific fields are: (i) uncertainty about future trends in the energy market and in energy policies; (ii) difficulties in financing innovation in some fields of technology (examples include solar thermal for electricity and ocean energy); and (iii) low capital stock turnover.

General Purpose Technologies and Complementary Innovations

General Purpose Technologies

There are four general purpose technologies in the alternative energy sector are the following.

1. Information technology which is used extensively in advanced electricity generation systems;

2. Advanced materials technology, which is used in solar photovoltaics, energy storage, and materials for hydrogen production processes, hydrogen storage and distribution.
3. Nanotechnology, which is used in solar cells, photovoltaics incorporated into building materials and surface coatings, energy storage systems, power electronics, sensors and controls in power plants, and fuel cells.
4. Bioenergy/agriculture, including innovation in agricultural production of feedstocks, quality control on biomass inputs, advances in methods of converting biomass into electricity and heat, its use in CHP and integrated production systems.

Inducements and Constraints

Inducements to utilise GPTs and undertake complementary innovations are:

- high fossil fuel prices, carbon taxes;
- exogenous improvements in competitiveness of GPTs; and
- widening use of GPTs in renewable energy.

The main constraints to broader-based innovation in alternative energy are the:

- high costs of technologies, limited applications, and high costs of accompanying R&D (examples include nanotechnology, and some new materials technologies); and
- level of adjustment costs.

Innovation in Business Processes

Substantial innovation in business processes will be required to get the best results for innovations in alternative energy technologies. Some of the main innovations in business processes required are summarise below.

1. Manufacturing systems. The chief example is nuclear energy, where business processes involving assembly and modularisation, the simplification of safety systems and processes associated with constructed power stations are needed.
2. Distributed energy systems. These require some combination of solar photovoltaics, fuel cells, and advanced energy storage in buildings or groups of buildings, plus grid integration as an option.
3. Integrated energy systems. Examples include integrating wind into hydropower systems, biomass into retrofit of existing coal plants, and advanced energy storage used with intermittent energy sources such as wind and photovoltaics, and grid integration for separate national or regional energy systems in order to make full use of the potential for renewables energy. Another example is the hydrogen economy – renewable

energy generates electricity (perhaps intermittent), water electrolysis produces hydrogen, advanced storage, transportation and distribution of hydrogen for use in a continuous centralised energy plant for base energy, or for the supply of hydrogen as a transport fuel.

4. Integrated production systems. Alternative energy technology can be used in an integrated industrial system for waste recovery and utilisation for supplementary heat and power. The hydrogen economy is an example of an integrated production system whereby fossil fuels are used as a base for hydrogen production, the resulting carbon dioxide being separated and stored or, alternatively, used in accompanying industrial processes), the hydrogen is used in fuel cells to generate electricity and heat for CHP systems which, in turn, provide energy and heat for accompanying industrial processes.

Public Research and Development

There is a huge list of topics related to alternative energy that would benefit form additional basic research in the public sector. These include the following project areas.

1. Nuclear energy – new safer reactor concepts, safe disposal and storage of nuclear waste, security of nuclear materials, and fusion technology.
2. Biomass – advanced gasification technologies, pyrolysis technologies, and advanced agricultural technologies.
3. Wind – offshore wind technologies, and advanced wind forecasting techniques.
4. Geothermal – enhanced geothermal systems, the exploitation of deep geothermal resources, advanced geothermal drilling techniques, and technologies to exploit geothermal hot dry rock resources.
5. Solar photovoltaics – new cell technologies, drawing on nanotechnology, organic thin films and molecular chemistry; advanced solar photo-conversion technologies; and technologies that integrate photovoltaics into building materials.
6. Solar thermal – research into alternative concentrated solar power technologies.
7. Ocean energy – offshore wave technology devices, marine current energy, the engineering aspects of OTEC technology; and scoping research into tapping the salt gradient.
8. Energy storage – new materials for electrochemical systems, new types of components for flywheels, better corrosion-resistant materials for batteries with higher power density, commercial high-temperature superconductors for magnetic energy systems, and improved power-conditioning systems.

9. Fuel cells – proton-exchange membrane, molten carbonate, solid oxide and polymer electrolyte fuel cells, and developing low-cost mass production techniques for fuel cells.
10. Hydrogen – methods of producing hydrogen by electrolysis, photolysis, biophotolysis, and high temperature decomposition, advanced hydrogen storage systems, advanced systems for distributing hydrogen, and simulation of integrated hydrogen systems.

4. Policies to Encourage Alternative Energy Technologies

Addressing the Barriers to Technology Development

The key aspects of a comprehensive emissions-saving policy for energy production are detailed below.

1. Increase non-renewable (high-emitting) primary energy prices by pricing in the external costs associated with producing and consuming such energy sources. This policy deals with market failure and stimulates the diffusion of new technologies and innovations in alternative energy technologies.
2. Reducing the real after-tax cost of alternative energy R&D. This includes aspects of market barriers and also market failure in relation to the public goods element of some R&D. It stimulates induced specialised innovation and GPT-induced innovation.
3. Increasing the volume/quality of public basic research in relevant scientific disciplines, increased public/private collaborative research, promoting the transfer of this research knowledge. It reduces market barriers and tackles a source of market failure. It stimulates commercial innovation.
4. Improving information about alternative technologies and the ability to assess the costs and benefits of such technologies. It deals with a market barrier, and stimulates diffusion and induced innovation.
5. Reducing transactions costs associated with alternative technologies. This is partly a question of information flows, partly a question of adaptability of management and appropriate training and selection of employees. Regulatory interventions in product and labour markets may increase such transactions costs. It deals with a market barrier and stimulates diffusion, induced specialised innovation, and GPT-induced innovation.
6. Reducing uncertainty associated with the adoption of alternative technologies. Uncertainty poses problems for the financing of R&D and hence the costs of innovation. It can be dealt with in a similar way to information gaps and transactions costs. It deals with a market barrier and stimulates diffusion and induced innovation.
7. Increased rates of learning-by-doing for alternative technologies. This is partly a question of lowering the costs of using such technologies, partly a question of encouraging the overall demand from end-users of the technology. It deals with a market barrier and stimulates diffusion. Market

support for new technology also encourages induced innovation, induced innovation, GPT-induced innovation.

8. Increasing the rate of capital stock turnover – encouraging (or reducing barriers to) investment in new energy capacity, increasing the retirement rate of old energy equipment. It deals with market barrier and stimulates diffusion, induced innovation and GPT-induced innovation.

The common element to many of the impediments to sustainable technology adoption is the presence of market barriers of one sort or another. Market barriers raise the cost of alternative energy technologies so as to constrain their growth. The IEA notes that policies to overcome market barriers include financing innovations through such means as subsidised infrastructure bonds or through the use of other financial incentives and the support for R&D designed to reduce technical risks. Market failure arises as a result of externalities and the public nature of some long-term R&D. This is best addressed through pricing strategies that reflect externalities and public R&D (IEA 2000).

Cost barriers to the adoption of radical new energy technologies will not be eliminated simply as a result of 'no-regrets' policies or programs that help to make the energy economy more efficient and environmentally aware. Large changes to the technologies employed in energy production will require changed price structures that favour low-carbon and low-emissions technologies (reducing market price distortions) and/or regulations and subsidies that will have a similar effect. Other forms of technology cost barriers need to be approached through efforts to lower the cost of new technologies, including assistance to R&D and support for technology learning (IEA 2000).

In some cases the use of new technology requires infrastructure investments that are beyond the capacity of any one-market actor to provide. Examples include district heating and cooling systems, which require distributions systems and integration with other energy facilities and the use of hydrogen as a fuel for energy production, which also requires new infrastructure. Governments can invest directly in new infrastructure or provide incentives for the private sector to do so (IEA 2000).

The technologies used in energy production face the barrier of *slow capital stock turnover*. Thermal power plants may have an economic life of 40 years[12]. In the absence of policy measures, it is possible that many of today's large fossil-fuel power plants will operate well into the 21st century, even up to 2050. As a result of these long lives, missed opportunities to put efficient and cleaner stock into place when old stock is refurbished or replaced, and when new stock is constructed or purchased, can perpetuate excess emissions for a long time. Actions to influence the type of new, replacement or refurbished equipment and infrastructure put into place are therefore potentially 'high-leverage' actions over the long term. Measures that can accomplish this include information programs, emissions standards, and 'portfolio requirements' mandating that a certain fraction of power generation be based on renewable fuels. Policies and measures may seek to increase the turnover rate of stock. This approach

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[12] The average age of U.S. power plants is about 30 years, but a significant fraction of U.S. generating capacity was originally built over 40 years ago (Lempert et al. 2002).

has not been used to a great extent; rather, the general approach has been to influence new investments. One policy measure that appears to have particular promise is the application of efficiency or emissions standards or environmental regulations to existing power plants (IEA 2000).

Finally, there is a compelling case for providing a stimulus to innovation across a broad range of technologies.

- Given the uneven global distribution of resources, it provides the maximum global reach for energy sector improvements.
- The principal driver of competition between energy forms would rest on innovation, thus ensuring a broader stimulus to increased energy efficiency and reduced emissions.
- It would enable more sustainable energy pricing to improve energy efficiency without unnecessary sacrifices to economic growth.
- It would reduce a key element of uncertainty in energy markets by providing a clearer picture of the future paths of technology in the energy sector, thus enhancing the capacity of the market to provide rational outcomes for the energy sector (IEA 2000).

The Use of Specific Policy Instruments

Economic Instruments

Carbon taxes are the preferred economic instrument for encouraging emissions-reducing alternative energy technologies. Market-based instruments produce superior results to command-and-control technologies (Jaffe et al. 2003).

Subsidies can be used to encourage the diffusion of technology and stimulate commercial innovation in areas requiring a special incentive. They may be necessary to enable the market for new technologies to attain a critical mass. Solar technologies, ocean energy, fuel cells and hydrogen technologies are examples of this principle.

Regulation

Regulation is an alternative to taxes and subsidies where the adoption of the latter at appropriate levels is politically infeasible.

IEA (2000) argues that the application of efficiency or emissions standards to existing as well as new power plants should be considered. Applying such measures to existing plants is likely to accelerate their replacement. Environmental regulations on emissions and waste products from power plants can make them uneconomic in their existing form and hasten fuel switching or retirements.

Science and Technology

The major issues relating to the science and technology policy for alternative energy are the volume and quality of basic R&D required and the supply of scientists and other professional needed to undertake this research.

The previous discussion highlighted the extensive range of R&D topics relevant to progressing alternative energy technologies. This implies a significant volume of resources need to be devoted to the task, and education and training needs to be provided to ensure an adequate supply of scientists, engineers and technologists are available to meet this challenge. Interchange between the private and public sectors is required to facilitate the flow-on form basic to applied research.

Finally, there is the question of how to determine an efficient allocation of public research resources. The agenda for research needs to be continuously re-assessed, and individual research programs evaluated. The International Energy Agency has an important role to play in providing in international mechanism for discussing and evaluating energy-related R&D.

Infrastructure

Alternative energy infrastructure is required in the following areas:

- grid integration the interconnection of renewables with the grid; interregional and international grid integration;
- hydrogen distribution infrastructure; and
- the storage of nuclear waste.

This infrastructure can be developed under three different models.

1. Public funding.
2. Public-private partnership agreements.
3. Private development and operation with the public sector setting and enforcing standards, with or without subsidies or tax-breaks.

Education and Information

Information

The aims of alternative energy information programs are to: (i) overcome information barriers to the diffusion of emissions-reducing technologies, and (ii) overcome information barriers that prevent the public from understanding the need for effective climate change policies to be adopted.

Technology demonstration programs can reduce uncertainty about the diffusion of technologies and increase the rate of learning-by-doing when new technologies are adopted. Education of consumers about the advantages of alternative energy in reducing emissions and the need to adopt policy measures that both encourage alternative energy and discourage traditional fossil-fuel-based energy.

Education and Training

The training of managers and employees in new alternative energy technologies would:

- increase the capacity of the private sector to make use of relevant basic research; and
- increase the propensity to innovate in both technologies and in business processes.

International Cooperation

Global cooperation is necessary to encourage the international spread of new alternative technologies. This cooperation should range from facilitating the diffusion of existing frontier technologies, encouraging international awareness of innovative research and cooperation in specific research where necessary, and identifying and attempting to resolve regulatory barriers to the commercialisation of such innovation.

In terms of basic research, there is a similar case for promoting awareness and cooperation. international cooperation will be particularly necessary in areas known as Big Science where the scale of the basic research required tends to exceed the capacities of purely national science and technology systems. The main examples of Big Science that pertain to alternative energy are research relevant to the hydrogen economy, particularly relating to the distribution and storage of hydrogen, and fusion energy.

5. Conclusions

Table 4 indicates the energy sources used in generating electricity according to the Reference Scenario of the IEA (2004a).

For the world as a whole, the dependence on fossil fuels to generate electricity is projected to actually increase between 2020 to 2030 – oil declines, coal holds its own, and gas increases substantially. Nuclear energy peaks by 2010 in absolute terms (2654 TWh in 2002, 2985 in 2010, 2929 in 2030), but declines in relative terms. The reduction in the relative importance of nuclear energy drags down the overall share of alternative energy in electricity generated. Hydropower increases by 62.8% from 2002 to 2030, but such is the demand for electricity, its share of total electricity generated declines. Biomass and waste increases by 200% (2002 to 2030), its share increases, but it fails to reach 3% of total electricity generated. Other renewables increase by more than 1000%, their share rises, but they are still under 4% of total electricity generated by 2030. For other renewables, wind is the star performer, others remain of minor importance, though increasing in share (solar, geothermal and wave energy).

In the OECD the following trends are noteworthy.

- There is less dependence on fossil fuels than for the world as a whole, but their share still rises.
- Nuclear capacity rises from 2276 TWh in 2002 to 2462 in 2010, then declines to 2137 in 2030.
- Hydro rises by 24% 2002-2030, but its share falls.
- Biomass and waste are up 140% (2002-2030) and are close to 3% by 2030.

- Other renewables increase by1100%, and their share rises from less than 1% to nearly 7%.
- Best performers in terms of increasing share among other renewables in order of their increased share are wind, solar, geothermal, and wave energy.

Table 4. IEA Reference Scenario for Sources of Electricity Generated, 2002 to 2030 (% shares of electricity generated)

OECD	2002	2010	2020	2030
Coal	38.26	36.09	34.99	33.25
Oil	5.72	4.18	3.49	2.17
Gas	17.52	21.01	25.62	29.10
Fossil fuels	61.49	61.27	64.09	64.52
Nuclear	23.33	21.78	17.77	15.00
Hydro	12.61	12.40	11.23	10.74
Biomass & waste	1.72	2.10	2.37	2.84
Other renewables	0.84	2.44	4.54	6.90
Alternative energy	38.50	38.73	35.91	35.48
Other renewables:				
Wind	0.49	1.82	3.58	5.26
Geothermal	0.34	0.48	0.54	0.65
Solar	0.01	0.11	0.33	0.75
Tide/Wave	0.01	0.04	0.09	0.24
DEVELOPING ECONOMIES	2002	2010	2020	2030
Coal	45.18	45.27	45.23	46.58
Oil	11.71	9.05	7.11	5.43
Gas	16.68	19.62	23.75	25.83
Fossil fuels	73.57	73.95	76.09	77.84
Nuclear	2.36	3.24	3.47	3.48
Hydro	22.74	20.62	18.09	15.70
Biomass & waste	0.72	1.19	1.18	1.41
Other renewables	0.58	0.98	1.19	1.57
Alternative energy	26.41	26.03	23.92	22.16
Other renewables:				
Wind	0.08	0.53	0.75	1.03
Geothermal	0.50	0.46	0.43	0.46
Solar	0.00	0.00	0.00	0.08
Tide/Wave	0.00	0.00	0.00	0.00
WORLD	2002	2010	2020	2030
Coal	38.83	38.11	37.92	38.19
Oil	7.35	5.88	4.95	3.73
Gas	19.10	21.93	26.51	29.47
Fossil fuels	65.27	65.92	69.38	71.40
Nuclear	16.51	14.79	11.55	9.25
Hydro	16.24	15.91	14.52	13.42
Biomass & waste	1.29	1.62	1.66	1.98
Other renewables	0.69	1.76	2.85	3.95
Alternative Energy	34.73	34.08	30.58	28.60
Other renewables:				
Wind	0.32	1.24	2.17	2.93
Geothermal	0.35	0.44	0.46	0.53
Solar	0.01	0.06	0.17	0.38
Tide/Wave	0.01	0.02	0.05	0.11

Source: IEA (200wa).

The trends in the electricity market among developing countries are disturbing, given the rapid rise in the demand for electricity (up 209% between 2002 and 2030). The following points are worth noting.

1. There is a much higher dependence on fossil fuels than in the advanced economies. This is particularly the case for coal and oil, whose emissions-intensity is higher than gas. The share of fossil fuels in electricity generated is projected to increase at a higher rate than in the OECD.
2. Hydro is the only alternative energy source whose share is higher in the developing economies than the OECD. It is projected to increase by 114% 2002-2030, much more rapidly than in the OECD, but not fast enough to maintain its relative share.
3. Nuclear capacity is only found in a few developing economies, but its share will rise somewhat between 2002 and 2030.
4. For biomass and waste, the share of electricity generated was 40% of the share in the OECD in 2002. An impressive growth of 500% from 2000 to 2030 is projected, its share will double, but still be below that of the OECD in 2002.
5. The share of other renewables in electricity generated is lower than the OECD in 2002 (0.58% to 0.84%) with geothermal more prominent, and wind of marginal importance.
6. The growth of renewables in the developing economies of 740% compares with 1100% in the OECD. The share rises to 1.57% in 2030, approximately the level projected for the OECD in 2007. The share of wind energy rises to 1.0%, around the current share in OECD, solar energy exhibits a similar trend, tide and ocean energy fails to develop at all.

The Reference Scenario indicates how much needs to be done before electricity generation can be pit onto a sustainable development path. Yet the prospective technologies exist to facilitate a major shift away from fossil fuels towards renewable energy, the long term prospects for nuclear energy may be improving, and, in Paper 8, the prospects for carbon capture and storage, which may facilitate huge reductions in the emissions-intensity of fossil fuels, are examined. With the right policies in place, major reductions in the level of emissions from electricity production may be secured in the advanced economies.

The key issue for the future is how to secure a major reduction in the emission-intensity of electricity production in the developing economies. Current and prospective trends indicate a very considerable lag between the development of alternative energy in the advanced economies and the adoption of alternative energy in the developing economies. The key to resolving this issue lies in overcoming the barriers that exist to the diffusion of emissions-reducing energy technologies to the developing economies.

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