

advanced energy supply technologies

CHAPTER 8

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Fossil energy technologies. Sustainability principles indicate that fossil energy technologies should evolve towards the long-term goal of near-zero air pollutant and greenhouse gas emissions—without complicated end-of-pipe control technologies. Near-term technologies and strategies should support this long-term goal.

The technological revolution under way in power generation—where advanced systems are replacing steam turbine technologies—supports this long-term goal. Natural-gas-fired combined cycles offering low costs, high efficiency, and low environmental impacts are being chosen wherever natural gas is readily available. Cogeneration is more cost-effective and can play a much larger role in the energy economy if based on gas turbines and combined cycles rather than on steam turbines.

Reciprocating engines and emerging microturbine and fuel cell technologies are strong candidates for cogeneration at smaller scales. Coal gasification by partial oxidation with oxygen to make syngas (mainly carbon monoxide, CO, and hydrogen, H₂) makes it possible to provide electricity through integrated gasifier combined cycle plants with air pollutant emissions nearly as low as for those plants using natural gas combined cycles. Today power from integrated gasifier combined cycle cogeneration plants can often compete with power from coal steam-electric plants in either cogeneration or power-only configurations.

Although synthetic liquid fuels made in single-product facilities are not competitive, superclean syngas-derived synthetic fuels that are produced in polygeneration facilities making several products simultaneously may soon be. Syngas can be produced from natural gas by steam reforming or other means or from coal by gasification with oxygen. Expanding markets for clean synthetic fuels are likely to result from toughening air pollution regulations. Synthetic fuels produced through polygeneration will be based on natural gas, if it is readily available. In natural-gas-poor, coal-rich regions, polygeneration based on coal gasification is promising.

The barriers to widespread deployment of advanced cogeneration and polygeneration systems are mainly institutional. Most such systems will produce far more electricity than can be consumed on site, so achieving favourable economics depends on being able to sell coproduct electricity at competitive prices into electric grids. Utility policies have often made doing so difficult, but under the competitive market conditions towards which electric systems are evolving in many regions, cogeneration and polygeneration systems will often fare well.

Near-term pursuit of a syngas-based strategy could pave the way for widespread use of H₂ as an energy carrier, because for decades the cheapest way to make H₂ will be from fossil-fuel-derived syngas. Syngas-based power and H₂ production strategies facilitate the separation and storage of carbon dioxide from fossil energy systems, making it possible to obtain useful energy with near-zero emissions of greenhouse gases, without large increases in energy costs. Successful development of fuel cells would, in turn, facilitate introduction of H₂ for energy. Fuel cells are getting intense attention, because they offer high efficiency and near-zero air pollutant emissions. Automakers

are racing to develop fuel cell cars, with market entry targeted for 2004–10.

Other advanced technologies not based on syngas offer some benefits relative to conventional technologies. But unlike syngas-based technologies, such options pursued in the near term would not offer clear paths to the long-term goal of near-zero emissions without significant increases in costs for energy services.

Nuclear energy technologies. World-wide, nuclear energy accounts for 6 percent of energy and 16 percent of electricity. Although it dominates electricity generation in some countries, its initial promise has not been realised. Most analysts project that nuclear energy's contribution to global energy will not grow and might decline in the near future. Nuclear power is more costly than originally expected, competition from alternative technologies is increasing, and there has been a loss of public confidence because of concerns relating to safety, radioactive waste management, and potential nuclear weapons proliferation.

Because nuclear power can provide energy without emitting conventional air pollutants and greenhouse gases, however, it is worth exploring whether advanced technologies might offer lower costs, restore public confidence in the safety of reactors, assure that nuclear programmes are not used for military purposes, and facilitate effective waste management.

In contrast to Chernobyl-type reactors, the light water reactors (LWRs) that dominate nuclear power globally have had a good safety record, though this has been achieved at considerable cost to minimise the risk of accidents.

The potential linkage between peaceful and military uses of nuclear energy was recognised at the dawn of the nuclear age. Steps taken to create a non-proliferation regime through treaties, controls on nuclear commerce, and safeguards on nuclear materials have kept peaceful and military uses separate. But if there is to be a major expansion of nuclear power, stronger institutional and technological measures will be needed to maintain this separation both for proliferation by nations and theft of weapons-usable materials by subnational groups.

Reactor vendors now offer several evolutionary LWRs with improved safety features and standardised designs, and there is some ongoing work on new reactor concepts.

Limited supplies of low-cost uranium might constrain LWR-based nuclear power development after 2050. Plutonium breeder reactors could address the resource constraint, but keeping peaceful and military uses of nuclear materials separate would be more challenging with breeders. Other possibilities for dealing with the resource constraint are extraction of uranium from seawater and thermonuclear fusion. There are many uncertainties regarding such advanced technologies, and all would take decades to develop.

Radioactive waste by-products of nuclear energy must be isolated so that they can never return to the human environment in harmful concentrations. Many in the technical community are confident that this objective can be met. But in most countries there is no consensus on waste disposal strategies. The current stalemate regarding waste disposal clouds prospects for nuclear expansion. ■

The arguments for marginal, incremental change are not convincing—not in this day and age. The future, after all, is not linear. History is full of sparks that set the status quo ablaze. —Peter Bijur, chief executive officer and chairman, Texaco, keynote speech to 17th Congress of World Energy Council, Houston, 14 September 1998

This chapter discusses advanced energy supply technologies with regard to their potential for facilitating the widespread use of fossil and nuclear energy sources in ways consistent with sustainable development objectives.¹ In each case the current situation is described, goals for innovation are formulated in the context of these objectives, near-term and long-term technology options are discussed in relation to these goals, and illustrative cost estimates are presented for options with reasonably well-understood costs.*

ADVANCED FOSSIL ENERGY TECHNOLOGIES

Fossil fuel supply considerations as a context for fossil energy innovation

Fossil energy technology development will be strongly shaped by energy supply security concerns and environmental challenges.

The emerging need for oil supplements in liquid fuel markets

Oil, the dominant fossil fuel, accounted for 44 percent of fossil fuel use in 1998. Although there is no imminent danger of running out of oil (chapter 5), dependence on oil from the Persian Gulf, where remaining low-cost oil resources are concentrated, is expected to grow. For example, the U.S. Energy Information Administration projects in its reference scenario that from 1997–2020, as global oil production increases by nearly 50 percent, the Persian Gulf's production share will increase from 27 to 37 percent (EIA, 1999a). This increase suggests the need to seek greater supply diversity in liquid fuel markets to reduce energy supply security concerns (chapter 4).

In addition, growing concerns about air quality are leading to increased interest in new fuels that have a higher degree of inherent cleanliness than traditional liquid fuels derived from crude oil, especially for transportation applications. To meet growing fluid fuel demand in the face of such constraints, some combination of a shift to natural gas and the introduction of clean synthetic fuels derived from various feedstocks (natural gas, petroleum residuals, coal, biomass) is likely to be needed to supplement oil during the next 25 years.

The oil crises of the 1970s catalysed major development efforts for synthetic fuels. For example, U.S. President Jimmy Carter's administration supported a synfuels programme that involved large government-supported commercialisation projects. Most such projects failed because the technologies were rendered uneconomic by the collapse of world oil prices in the mid-1980s. But, as will be shown, emerging synfuel technologies generally have better environmental characteristics and, when deployed through innovative multiple-energy-product (poly-generation) strategies, reasonably good economic prospects, even

at relatively low oil price levels. Moreover, the private sector, rather than the government, is taking the lead in advancing these new technologies. The government's role has shifted from managing demonstration projects to supporting research and development that enables private-sector-led commercialisation and to helping remove institutional barriers to deployment.

Entering the age of gas

For natural gas, the cleanest, least-carbon-intensive fossil fuel, ultimately recoverable conventional resources are at least as abundant as for oil (chapter 5). Although the global consumption rate for gas is about half that for oil, the abundance of natural gas and its economic and environmental attractiveness have led it to play a growing role.² Since 1980 the share of natural gas in the global energy economy has grown, while oil and coal shares have declined. Wherever natural gas supplies are readily available, the natural-gas-fired gas-turbine-steam-turbine combined cycle (NGCC) has become the technology of choice for power generation, in which applications it is typically both the cleanest and least-costly fossil fuel option. As will be shown, clean natural-gas-derived synthetic fuels also have good prospects of beginning to compete in liquid fuels markets.

For developing countries, the huge investments needed for natural gas infrastructure (pipelines, liquid natural gas facilities) are daunting. But NGCC plants might be built as targeted initial gas users, using the revenues to facilitate infrastructure financing.

Alternatives to conventional gas might be needed to meet the growing demand for fluid fuels in 2025–50. Options include synthetic fluid fuels derived from coal and various unconventional natural gas resources (chapter 5).

Unconventional natural gas resources associated with methane hydrates are especially large, although the quantities that might be recoverable and delivered to major markets at competitive costs are highly uncertain (chapter 5). There is little private sector interest in better understanding the magnitude and cost dimensions of the methane hydrate resource, because conventional natural gas supplies

* Life-cycle costs are presented for an assumed 10 percent real (inflation-corrected) cost of capital (discount rate), neglecting corporate income and property taxes. Neglecting such taxes is appropriate in a global study such as this report, partly because tax codes vary markedly from country to country, and partly because such taxes are transfer payments rather than true costs. Moreover, such capital-related taxes discriminate against many capital-intensive technologies that offer promise in addressing sustainable development objectives. Including such taxes, annual capital charge rates—including a 0.5 percent a year insurance charge—are typically 15 percent for a plant with a 25-year operating life, in comparison with 11.5 percent when such taxes are neglected (U.S. conditions).

The most formidable challenges facing the fossil energy system are likely to be achieving near-zero emissions of air pollutant and CO₂ emissions.

are abundant on time scales of interest to business.

An understanding of methane hydrate issues is important for decisions on near-term research and development priorities related to unconventional gas resource development versus coal synthetic fuels development. For this reason—as well as the theoretical potential of the hydrate resource and the attractions of natural gas as an energy carrier—the U.S. President's Committee of Advisors on Science and Technology has urged international collaborative research and development in this area, building on embryonic efforts in India, Japan, and Russia (PCAST Energy Research and Development Panel, 1997; PCAST Panel on ICERD³, 1999).

The drawbacks and attractions of coal

Coal use is declining in most industrialised countries other than the United States, where use is expected to grow slowly. World-wide, coal use is expected to grow as fast as oil use, with much of the growth accounted for by China, whose global share might increase from 30 percent today to nearly 50 percent by 2020 (EIA, 1999a).

For coal, the dirtiest, most carbon-intensive fossil fuel, global resources are abundant (chapter 5). Coal is generally less costly than other fossil fuels. Substantial productivity gains have been made for coal production in both Australia and the United States (Williams, 1999b). Such gains can be expected in other regions once energy market reforms are put in place. Productivity gains have caused coal prices in the United States to decline by a factor of 2 since the early 1980s, to a level half that for natural gas.

During the next 20 years, a 20 percent rise in the price of natural gas and a 30 percent drop in the price of coal are expected in the United States (EIA, 1998a), leading to growth in the price ratio to 3.5. In Europe coal prices are not as low as in the United States, but even there the average price of coal imported into the European Union fell by more than a factor of 2 between 1983 and 1995 (Decker, 1999).

Although many regions are moving away from coal, this chapter shows that there are reasonable prospects that improved technology could propel a shift back to coal by making it feasible to provide from coal, at attractive costs, energy systems characterised by near-zero emissions of both air pollutants and greenhouse gases. Concerted efforts to develop and commercialise such technologies are desirable in light of the strategic importance of coal to coal-rich countries where conventional oil and natural gas resources are scarce (for example, China and India).

Setting goals for advanced fossil energy technologies

Designing advanced fossil energy technologies to be compatible with sustainable development requires that:

- Fossil energy be widely affordable.
- Fossil energy help satisfy development needs not now being met.
- Energy supply insecurity concerns be minimised.
- Adverse environmental impacts be acceptably low.
- For the longer term, emissions of carbon dioxide (CO₂) and other

greenhouse gases be sufficiently low to meet the objectives of the United Nations Framework Convention on Climate Change (UNFCCC, 1992).³

If fossil fuels are to play major roles in facilitating sustainable development, all these objectives must be met simultaneously—which is impossible with today's technologies. Thus there is a need for substantial research, development, demonstration, and deployment programmes aimed at launching advanced, sustainable fossil energy technologies in the market. Because resources available to support energy innovation are scarce (and the fossil energy community must share these scarce resources with the end-use energy efficiency, renewable energy, and nuclear energy communities), criteria should be established for the long-term goals of the innovation effort. In addition, alternative technological strategies should be assessed with regard to their prospects for meeting these goals. This section introduces sustainable development goals for advanced fossil energy technologies. Later sections discuss the prospects for meeting these goals with alternative clusters of technologies.

The objective of making energy widely affordable is satisfied for most consuming groups with existing fossil energy technologies, which tend to be the least costly energy supplies. Addressing other sustainability objectives simultaneously will tend to increase costs. However, advanced technologies can help contain costs when these other objectives are also pursued. Moreover, as will be shown, new approaches to organising energy systems so that multiple products are made in a single facility—polygeneration strategies—can also lead to lower energy costs. The fossil energy technologies with the greatest potential to meet environmental goals are especially well-suited to polygeneration.

A key aspect of the objective of satisfying unmet energy needs for development involves giving the poor—especially the rural poor in developing countries—access to clean, modern energy carriers. Clean cooking fuels and electricity to satisfy basic needs are particularly important (chapters 2, 3, and 10). Advanced fossil energy technologies can help address these needs. Innovations in synthetic fuel technology, together with the attractive economics associated with deploying such technologies in polygeneration configurations, make the prospects for clean synthetic fuels much brighter today than they have been.

Some of the most promising synthetic fuels (such as dimethyl ether, or DME) are attractive energy carriers for serving both cooking fuel and transportation markets. The revolution in power-generating technology and the market reforms that are making small-scale power generation (reciprocating engines, microturbines, fuel cells) increasingly attractive economically in grid-connected power markets can also be deployed in remote rural markets, many of which are not currently served by grid electricity. Even in such markets where fossil fuels are not readily available, these systems can be adapted for use with locally available biomass resources in rural areas (Mukunda, Dasappa, and Srinivasa, 1993; Kartha, Krutz, and Williams, 1997; Henderick, 1999; Henderick and Williams, 2000). Likewise,

clean synthetic fuels for cooking can also be derived from biomass (Larson and Jin, 1999). Fossil energy technology advances have made biomass applications feasible for both small-scale power generation and synthetic cooking fuel production.

To a large extent, the objective of minimising energy supply insecurity concerns can be addressed with advanced fossil energy technologies by pursuing opportunities to diversify the supply base for fluid fuels. Especially promising are opportunities to make synthetic fluid fuels through polygeneration strategies—using petroleum residuals, natural gas, and coal as feedstocks as appropriate, depending on local resource endowments. And for the longer term, successful development of methane clathrate hydrate technology could lead to improved energy security for a number of economies that heavily depend on imported hydrocarbons but have large off-shore hydrate deposits (such as India, Japan, Republic of Korea, and Taiwan, China).

The objective of making adverse environmental impacts acceptably low requires addressing the question: how low is low enough? Among environmental impacts, air pollution effects are especially important, for developing and industrialised countries alike. Moreover, adverse health impacts of air pollution tend to dominate overall air pollution impacts (chapter 3).

For many developing countries, the cost of the environmental damage caused by air pollution is high even though per capita energy consumption is low—mainly because pollution controls are largely lacking.⁴ Costs from air pollution are also high for industrialised countries with strong pollution controls,⁵ not only because of much higher energy consumption but also because the cost of uncontrolled emissions grows much faster than energy consumption, given that economists measure these costs on the basis of willingness to pay to avoid these damages (chapter 3).⁶ Tables 8.1 and 8.2 show that even low estimates of these damage costs are significant relative to typical direct economic costs (direct costs are \$0.03–0.04 a kilowatt-hour for electricity and \$0.20–0.30 a litre for transport fuels) for both coal power plants and for automobiles, but are low for modern natural gas power plants.⁷

Here it is assumed that a major long-term goal for advanced fossil energy technology that is implicit in the objective of making adverse environmental impacts acceptably low is near-zero air pollutant emissions—without the need for complicated and costly end-of-pipe control technologies. ‘Near-zero emissions’ is taken to mean emissions so low that residual environmental damage costs are a tiny fraction of the direct economic cost of energy. ‘Long-term’

TABLE 8.1. EMISSION RATES FOR AND ESTIMATED COSTS OF ENVIRONMENTAL DAMAGE FROM AIR POLLUTANT EMISSIONS OF FOSSIL FUEL POWER PLANT (LOW VALUATION FOR TYPICAL EUROPEAN CONDITIONS)

Primary air pollutant	Emission rate (grams per kilowatt-hour)			Low estimate of costs of environmental damages (dollars per thousand kilowatt-hours) ^a				Environmental damage costs relative to NGCC
	SO ₂	NO _x	PM ₁₀	SO ₂	NO _x	PM ₁₀	Total	Total
Average U.S. coal steam-electric plant, 1997	6.10 ^b	3.47 ^b	0.16 ^c	15.9	13.9	0.7	30.5	82
New coal steam-electric plant with best available control technology ^d	0.46	0.87	0.15 ^c	1.2	3.5	0.6	5.3	14
Coal IGCC plant ^e	0.075	0.082	0.0025	0.20	0.33	0.01	0.54	1.5
NGCC plant ^f	—	0.092	—	—	0.37	—	0.37	1.0

a. Environmental damage costs from power plant air pollutant emissions are assumed to be 25 percent of the median estimates of Rabl and Spadaro (2000) for typical power plant sitings in Europe. (The Rabl and Spadaro calculations were carried out under the European Commission’s ExternE Programme. Nearly all the estimated costs of environmental damages are associated with adverse health impacts; the economic values of health impacts were estimated on the basis of the principle of willingness to pay to avoid adverse health effects.) Rabl and Spadaro considered a wide range of pollutants, but the only significant damage costs were from SO₂, NO_x, and PM₁₀, for which their median estimates of damage costs (in dollars per kilogram) were \$10.44, \$16.00, and \$17.00. Damage costs at 25 percent of the median estimates of Rabl and Spadaro (equivalent to one standard deviation below the median) are assumed, to put a conservatism into the calculation to reflect the scientific uncertainty. b. Average emission rates in 1997 for U.S. coal plants, whose average efficiency was 33 percent (EIA, 1998b). c. In 1990 PM₁₀ emissions from U.S. electric utility coal power plants amounted to 245,000 tonnes (Spengler and Wilson, 1996) when these plants consumed 17.1 exajoules of coal (EIA, 1998b), so the PM₁₀ emission rate was 14.34 grams per gigajoule—the assumed emission rate for all steam-electric cases in this table. d. It is assumed that the new coal steam-electric plant is 35.5 percent efficient; that the coal contains 454 grams of sulphur per gigajoule (1.08 percent sulphur by weight), the average for U.S. coal power plants in 1997 (EIA, 1998b); that SO₂ emissions are reduced 95 percent, a commercially feasible rate; and that the NO_x emission rate is 86 grams per gigajoule—achievable with advanced low-NO_x burners that will be commercially available shortly; e. It is assumed that the coal integrated gasifier combined cycle (IGCC) plant is 43.8 percent efficient, based on use of steam-cooled gas turbines (see table 8.4); that the emission rates equal the measured values for the Buggenum coal IGCC plant (Netherlands): 10.0 and 0.3 grams per gigajoule of coal for NO_x and particulates, respectively, as well as 99 percent sulphur recovery (data presented by Co van Liere, KEMA, at the Gasification Technologies Conference in San Francisco, 17–20 October 1999); and that the coal contains 454 grams of sulphur per gigajoule. f. It is assumed that the natural gas combined cycle (NGCC) plant is 54.1 percent efficient, based on use of steam-cooled gas turbines (see table 8.4); and that the NO_x emission rate is 9 parts per million on a dry volume basis (at 15 percent O₂), corresponding to an emission rate of 0.092 grams per kilowatt-hour.

TABLE 8.2. EMISSION RATES FOR AND ESTIMATED COSTS OF ENVIRONMENTAL DAMAGE FROM AIR POLLUTANT EMISSIONS OF AUTOMOBILES (LOW VALUATION FOR TYPICAL FRENCH CONDITIONS)

Fuel and driving environment	Fuel economy (kilometres per litre)	Emission rate (grams per kilometre)		Low estimate of costs of environmental damages, EU conditions ^a (dollars)								
				Per kilogram		Per thousand kilometres of driving			Per thousand litres of fuel consumed			
		NO _x	PM	NO _x	PM	NO _x	PM	Total ^b	NO _x	PM	Total ^b	
Gasoline^c												
Urban ^d	8.7	0.68	0.017	5.5	690	3.7	11.7	16.6	32	102	144	
Rural ^d	10.3	0.79	0.015	6.8	47	5.4	0.71	7.3	56	7.3	75	
Diesel												
Urban ^d	10.4	0.75	0.174	5.5	690	4.1	120	125	43	1250	1300	
Rural ^d	12.7	0.62	0.150	6.8	47	4.2	7.1	12.5	53	90	159	

a. Environmental damage costs from automotive air pollutant emissions are assumed to be 25 percent of the median estimates presented in Spadaro and Rabl (1999) and Spadaro and others (1998)—calculations carried out under the European Commission's ExternE Programme. Nearly all the estimated costs of environmental damages are associated with adverse health impacts; the economic values of health impacts were estimated on the basis of the principle of willingness to pay to avoid adverse health effects. Damage costs at 25 percent of the mean estimates in these studies (equivalent to one standard deviation below the median) are assumed, to put a conservatism into the calculation to reflect the scientific uncertainty. b. Total costs per kilometre include, in addition to costs associated with NO_x and PM emissions, costs associated with emissions from CO, volatile organic compounds (VOC), SO₂, and benzo-a-pyrene (BaP). c. For a gasoline internal combustion engine car equipped with a catalytic converter. d. Urban cost estimates are for driving around Paris, where the average population density is 7,500 per square kilometre. Rural costs estimates are for a trip from Paris to Lyon, for which the average density of the population exposed to the automotive air pollution is 400 per square kilometre.

is defined as 2015 and beyond. Thus the goal of near-zero emissions is a target for energy innovation (research, development, demonstration, early deployment) rather than a near-term regulatory goal. There are five readily identifiable reasons for setting such an ambitious goal for emissions.

First, air pollution damage costs are associated largely with small-particle pollution, for which there appears to be no threshold below which the pollution is safe (chapter 3). Second, the trend has been towards continually more stringent controls on emissions in industrialised countries, both as a result of improved knowledge of adverse impacts and of increasing societal demands for cleaner air as incomes rise. But meeting air quality goals by continually ratcheting up the required end-of-pipe controls has proven very costly—both because the cost of reducing emissions by the next increment tends to increase sharply with the level of reduction, and because the continual technological change required to keep up with evolving regulatory goals can be very costly when there is not enough time between changes in regulations to recover the cost of the last incremental improvement before the next one must be made.

Third, regulations calling for ever tighter end-of-pipe controls on emissions are sometimes not nearly as effective in meeting air quality goals as they are supposed to be, as is illustrated by the wide gap between actual emission levels and regulated emission levels for U.S. cars—a gap that has been projected to increase in the future, as regulations tighten (table 8.3).⁸ Fourth, even for developing countries, the long-term near-zero emissions goal makes sense, because much of the energy technology that will be put into place in the period 2015–25 will still be operating decades later when incomes and societal desires for clean air will be high.⁹ And fifth, there are promising technological options for converting the near

zero emissions goal into reality. For example, managers of the U.S. Department of Energy's fossil energy programme have enough confidence in this idea to have created a new programme that seeks to develop new fossil energy technologies by 2015 that are characterised, among other things, by near-zero air pollutant emissions, as well as zero solid and liquid waste discharges.¹⁰

The challenge of setting goals with regard to the objective of preventing dangerous anthropogenic interference with the climate system is complicated by the fact that there is not yet agreement in the global community as to the level at which atmospheric CO₂ should be stabilised. However, the level that is eventually decided on is likely to be far below the level to which the world would evolve for an energy system that would follow a business-as-usual path. The IS92a scenario of the Intergovernmental Panel on Climate Change might be considered a business-as-usual energy future (IPCC, 1995). In this scenario the CO₂ emission rate grows from 7.5 gigatonnes of carbon (GtC) in 1990 (6.0 GtC from fossil fuel burning plus 1.5 GtC from deforestation) to 20 GtC in 2100. By way of contrast, stabilisation at twice the pre-industrial CO₂ level (550 parts per million by volume, a target favoured by various groups) would require reducing annual fossil energy emissions to 5.5 GtC by 2100. Stabilisation at 450 parts per million by volume (up from 360 parts per million by volume today) would require emissions falling to about 2.5 GtC by 2100 (DOE, 1999).

Many believe that coping adequately with the challenge of climate change will require major shifts to renewable energy sources, nuclear energy sources, or both. Although such shifts might be desirable for a variety of reasons, climate change concerns do not necessarily require a major shift away from fossil fuels. To be sure, the dimensions of the challenge are such that the deep reductions in CO₂ emissions that might be required during the next 100 years cannot be achieved

only by making efficiency improvements in fossil energy conversion, however desirable energy efficiency improvements might be. But energy efficiency improvement is not the only option for reducing CO₂ emissions from fossil fuels. The energy content of these fuels can also be recovered while preventing the release of CO₂ into the atmosphere—for example, by separating out the CO₂ and sequestering it in geological formations or in the deep ocean.

There is growing optimism in the scientific and technological communities that fossil energy systems can be made compatible with a world of severely constrained greenhouse gas emissions (Socolow, 1997). This optimism is reflected in new fossil energy research and development programmes (for example, in Japan, Norway, and the United States) that aim to achieve near-zero emissions from fossil energy systems. As will be shown, even with some already developed technologies it appears feasible to achieve deep reductions in CO₂ emissions without large increases in fossil energy costs. Although uncertainties regarding storage security and potentially adverse environmental impacts (especially for ocean sequestration) must be resolved before a high degree of confidence can be assigned to this option, there is growing scientific confidence that the potential for sequestering CO₂ is vast.

How can such considerations be used to frame goals for advanced fossil energy technologies that are consistent with the UN Framework Convention on Climate Change, when global society has not yet decided what goal is needed? In light of the long lead times required to bring new technologies to market at large scales, and considering that energy research and development is cheap insurance for addressing the climate change challenge (PCAST Energy Research and Development Panel, 1997), it is assumed here that a major element of the overall fossil energy innovation effort should be to develop the capacity to achieve deep reductions in CO₂ and other greenhouse gases. Thus, if global society eventually decides that deep reductions are needed, the fossil energy community will be prepared to respond

with advanced technologies and strategies. As with air pollution, the goal of reducing greenhouse gas emissions to near zero is a target for capacity development through technological innovation over the long term, rather than for near-term regulations.

Of the challenges facing the fossil energy system in moving towards sustainable development, the most formidable are likely to be near-zero emissions of air pollutants and CO₂. Consequently, these two challenges are given the greatest emphasis in the following sections.

Technologies and strategies for moving towards near-zero emissions

This section describes fossil energy technologies and strategies that offer considerable promise to meet all the sustainable development criteria set forth in the previous section, including, for the longer term, the especially daunting criteria of near-zero emissions of both air pollutants and greenhouse gases. Near-zero emissions could be achieved in the long term if the dominant energy carriers were electricity and hydrogen (H₂). The importance of having H₂ as an option complementing electricity as an energy carrier is discussed in box 8.1.

Here technologies are first discussed for power generation and then for synthetic fuels production. Key near-term strategies to hasten the widespread use of these technologies are cogeneration (combined heat and power) and polygeneration, which entails the simultaneous production of various combinations of synthetic fuels, electricity, process heat, and chemicals. Cogeneration and polygeneration offer favourable economics that can facilitate the industrial development of energy production technology based on synthesis gas (a mixture of gases consisting mainly of CO and H₂), which will subsequently be called syngas. Syngas is a key intermediate energy product that makes it possible to make many clean final energy products from fossil fuels—including, for the longer term, H₂.

TABLE 8.3. ESTIMATED COSTS OF ENVIRONMENTAL DAMAGE FROM NO_x EMISSIONS OF AUTOMOBILES (LOW VALUATION FOR TYPICAL FRENCH CONDITIONS, ASSUMING U.S. REGULATED AND ESTIMATED ACTUAL EMISSION LEVELS)

Model year	NO _x emission rate (grams per kilometre)		Estimated environmental damage cost (dollars per thousand kilometres, low estimate, French conditions; 55 percent urban + 45 percent rural driving, so that average cost = \$6.1 per kilogram) ^a		New car fuel economy (kilometres per litre)	Estimated environmental damage costs (dollars per thousand litres of gasoline)	
	Regulated level	Estimated actual level ^b	Emissions at regulated level	Estimated actual emissions		Emissions at regulated level	Estimated actual emissions
1993	0.62	1.1	4	7	11.8	45	79
2000	0.25	0.8	2	5	11.9	18	58
2010	0.12	0.5	1	3	12.8	9	39

a. Low estimates of the costs of environmental damages for NO_x emissions from gasoline-powered automobiles operated under French conditions (from table 8.2): \$5.5 per kilogram for urban areas and \$6.8 per kilogram for rural areas. For regions other than France, costs at the same per capita GDP levels will scale roughly according to the regional population density. b. From Ross, Goodwin, and Watkins, 1995.

BOX 8.1. THE STRATEGIC IMPORTANCE OF HYDROGEN AS AN ENERGY CARRIER

For the long term, it is desirable that the energy system be based largely on inherently clean energy carriers. Like electricity, during its use hydrogen (H₂) generates zero or near-zero emissions of air pollutants and CO₂. And, as for electricity, it can be produced from fossil fuels as well as from non-carbon-based primary energy sources through various processes characterised by near-zero emissions of air pollutants and CO₂ (see the section below on enhancing prospects for H₂).

The importance of having H₂ as well as electricity as an inherently clean energy carrier stems from the difficulty of using electricity efficiently and cost-effectively in some important markets such as transportation. In principle, near-zero emissions could be realised throughout the energy economy with electricity, which accounts for a third of global CO₂ emissions from burning fossil fuels. In practice, however, for most applications electricity use is limited mainly to systems that can be supplied with electricity relatively continuously from stationary sources, because of the difficulties that have been encountered in evolving suitable cost-competitive electricity storage technologies.

Consider that although the zero-emissions mandate for cars in California was focused initially on developing battery-powered electric cars, the goal of producing light-weight, low-cost batteries with adequate range between rechargings has proven an elusive technological challenge; this difficulty is one of the factors that has resulted in refocusing much of the zero-emission-vehicle quest on fuel cells, with the expectation that ultimately fuel cell vehicles will be fuelled with H₂. Although storing H₂ onboard vehicles is more difficult than storing liquid fuels, providing enough low-cost storage capacity to reduce refuelling rates to acceptable levels for consumers is a far less daunting challenge for H₂ than for electricity.

More generally, development of near-zero-emitting H₂ energy systems is desirable because modellers expect, under business-as-usual conditions, major continuing high demand levels for fluid (liquid and gaseous) fuels and high levels of CO₂ emissions associated with fluid fuels production and use. Consider, for example, the reference IS92a scenario (IPCC, 1995). Although electricity's share of worldwide secondary energy consumption grows from 15 percent in 1990 to 28 percent in 2100, the fluid fuel share is only slightly less in 2100 than in 1990 (57 versus 64 percent) in the IS92a scenario.

Moreover, because of the projected rapidly growing importance of synthetic fuels after 2050, fluid fuel production accounts for 60 percent of IS92a's 20 GtC of total energy-related CO₂ emissions in 2100, up from 47 percent of the 6 GtC of total energy-related CO₂ emissions in 1990. Thus, even if electricity generation could be made 100 percent free of CO₂ emissions by 2100 (through a shift of projected fossil electric generation to some mix of renewable energy, nuclear energy, and decarbonised fossil energy), emissions in 2100 would still be double those of 1990 (even though CO₂-neutral biomass produced at a rate equivalent to more than half of total primary energy use in 1990 provides a third of total synthetic fuels in 2100).

Having available H₂ as well as electricity provided by production systems with near-zero emissions would provide society with the capacity to achieve, in the longer term, deep reductions in CO₂ emissions from the fluid fuel sectors as well as from the electric sector, and thereby help make it possible to limit the CO₂ level in the atmosphere to twice the pre-industrial level or less in response to climate change concerns.

Advanced technologies for power generation and cogeneration

Promising advanced power generation and cogeneration technologies for the near (less than 5 years) to medium (5–15 years) term include natural-gas-fired gas-turbine-based technologies, coal integrated gasifier

combined cycle (IGCC) technologies, small engines suitable for distributed cogeneration applications, and various fuel cell technologies.

Natural-gas- and gas-turbine-based technologies. The pace of technological change has been brisk for gas turbines,¹¹ to the point where efficiencies are now comparable to those for coal steam-electric plants, even though turbine exhaust gas temperatures are high. To avoid wasting exhaust gas heat, gas turbines used in central-station power plants for purposes other than meeting peak loads are typically coupled through heat recovery steam generators to steam turbines in gas turbine–steam turbine combined cycles.

Table 8.4 presents cost and performance characteristics of two NGCC units: a 50 percent efficient* Frame 7F unit (commercially available) equipped with air-cooled gas turbine blades and a 54 percent efficient Frame 7H unit (available in 2000 or after) equipped with steam-cooled turbine blades.¹² In competitive power markets, installed costs of NGCCs have fallen to less than \$500 per kilowatt-electric. For typical U.S. and European fuel prices, modern NGCCs can provide electricity at lower cost and about 60 percent less CO₂ emissions per kilowatt-hour than coal steam-electric plants (see table 8.4).

Thermal nitrogen oxide (NO_x) generated in the combustor by oxidising nitrogen from the air at high flame temperatures is the only significant air pollutant arising from NGCC operation. But even in areas with tight regulations on NO_x emissions,¹³ modern NGCCs are often able to meet regulatory requirements without having to install costly end-of-pipe controls, by premixing fuel and air for the combustor and thereby avoiding high flame temperatures. With this technology, NO_x emissions per kilowatt-hour are only 10 percent of those for coal steam-electric plants equipped with the best available control technology, and overall costs of pollution damages from NGCCs are one-fourteenth of those for coal plants equipped with the best available control technology (see table 8.1).

Opportunities for innovation are not exhausted. One option is to eliminate entirely the relatively capital-intensive steam turbine in a so-called Tophat[®] cycle that involves heating air exiting the compressor with turbine exhaust heat and spray intercooling during compression (van Lier, 1998). By injecting a mist of fine water particles into the compressor to cool the air during compression (using hot water produced from turbine exhaust heat), compressor work requirements are greatly reduced, and net turbine output and efficiency are increased.¹⁴

One study applying the Tophat[®] concept to a redesign of a modern aeroderivative gas turbine estimated that the gas turbine output would increase from 47 to 104 megawatts-electric, the efficiency would increase from 36.5 to 52.2 percent (almost to the level for the 400-megawatt-electric Frame 7H NGCC; see table 8.4), and NO_x emissions would be substantially reduced. The capital cost per kilowatt-electric for such a unit is expected to be less than for NGCCs (van Lier, 1998).¹⁵

In addition, during the next 10 years, system efficiencies might increase further to levels of nearly 60 percent, as technological advances make it possible for turbine inlet temperatures to move up to about 1,500 degrees Celsius, and various cycle configurations (for example, reheating and intercooling) are exploited (Chiesa and others, 1993).

*Efficiencies in this chapter are expressed on a higher heating value (HHV) basis unless explicitly indicated otherwise.

TABLE 8.4. PERFORMANCE, GENERATION COSTS, AND CO₂ EMISSION RATES FOR ALTERNATIVE CONVENTIONAL FOSSIL FUEL POWER PLANTS

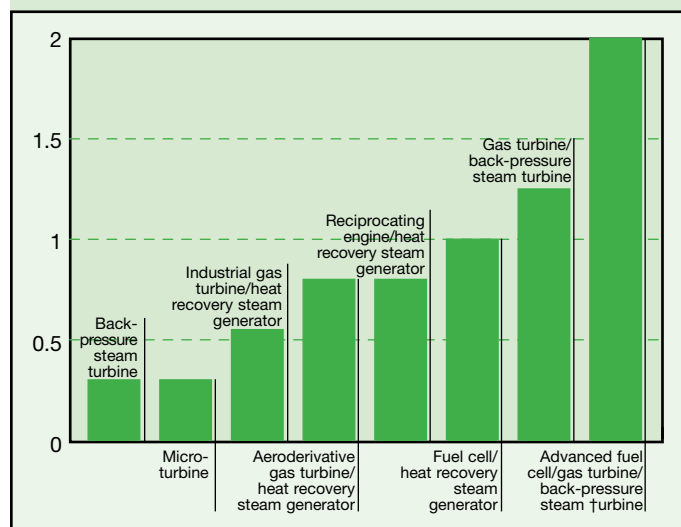
Performance, costs, and emission rates ^a	Pulverised coal steam-electric plant with flue gas desulphurisation	Coal integrated gasifier combined cycle (IGCC) plant		Natural gas combined cycle (NGCC) plant	
		Air-cooled turbine	Steam-cooled turbine	Air-cooled turbine	Steam-cooled turbine
Plant capacity (megawatts)	500	500	400	506	400
Efficiency (percent, higher heating value [HHV] basis)	35.5	40.1	43.8	50.2	54.1
Installed capital cost (dollars per kilowatt)	1090	1320	1091	468	445
Generation cost components (dollars per thousand kilowatt-hours)					
Capital charges ^b	17.9	21.7	17.9	7.7	7.3
Fixed operation and maintenance	2.3	2.8	3.0	2.3	2.3
Variable operation and maintenance	2.0	2.0	2.1	1.5	1.5
Fuel					
Typical U.S. fuel price ^c	10.1	9.0	8.2	19.4	18.0
Typical European fuel price ^c	17.2	15.3	14.0	22.9	21.3
Total generation cost (dollars per thousand kilowatt-hours)					
Typical U.S. fuel price ^c	32.3	35.5	31.2	30.9	29.1
Typical European fuel price ^c	39.4	41.8	37.0	34.4	32.4
CO₂ emission rate (grams of carbon per kilowatt-hour)^d	238	210	193	98	91

a. Plant capacities, installed capital costs, operation and maintenance costs, and plant efficiencies are from Todd and Stoll (1997). Combined cycle plants with air-cooled and steam-cooled gas turbine blades involve use of General Electric Frame 7F (commercial) and Frame 7H (near commercial) gas turbines, respectively. b. Capital charges are calculated assuming a 10 percent discount rate, a 25-year plant life, and an insurance rate of 0.5 percent a year, and neglecting corporate income taxes, so that the annual capital charge rate is 11.5 percent. It is assumed that all power plants are operated at an average capacity factor of 80 percent. c. For the United States: coal and natural gas prices of \$1.00 and \$2.70 per gigajoule, respectively (average prices projected by the U.S. Energy Information Administration for electric generators in 2010; EIA, 1998a). For Europe: prices for electric generators of \$1.70 per gigajoule for coal (average for OECD countries in 1997) and \$3.20 per gigajoule for natural gas (average for Finland, Germany, Netherlands, and United Kingdom for 1997). d. The carbon contents of coal and natural gas are assumed to be 23.4 kilograms of carbon per gigajoule and 13.7 kilograms of carbon per gigajoule, respectively.

If there are opportunities for using steam (for example, in support of an industrial process), hot gas turbine exhaust gases can be used to produce this steam in cogeneration configurations. Combined cycles can also be used for cogeneration—for example, by installing a back-pressure steam turbine instead of a condensing steam turbine with the gas turbine. With a back-pressure turbine, the high-quality steam produced from the gas turbine exhaust heat is first used to produce some electricity, and subsequently the lower quality steam discharged in the steam turbine exhaust is used for process applications. For such a system the ratio of produced electricity to process steam is higher than for a simple cycle gas turbine (figure 8.1).

Cogeneration is especially important in the near term for rapidly industrialising countries. Because these countries are in the early stages of building their infrastructure, their process-heat-intensive, basic-materials-processing industries are growing rapidly. Rapidly growing steam loads represent important resource bases for cogeneration, so that these industries have the potential of becoming major providers of clean, cost-competitive power. In this context, cogeneration systems employing gas turbines and combined cycles equipped with back-pressure turbines provide several times as much electricity per unit of process steam as systems based on simple back-pressure turbines (figure 8.1). These and other cogeneration technologies characterised by high output ratios of electricity to steam (for example, reciprocating internal combustion engines and fuel cells) make it

FIGURE 8.1. OUTPUT RATIOS OF POWER (KILOWATTS-ELECTRIC) TO HEAT (KILOWATTS-THERMAL) FOR ALTERNATIVE COGENERATION TECHNOLOGIES



Note: Ratios are for systems producing 10 bar steam. All steam turbines are back-pressure steam turbines with no steam condenser.

Source: Simbeck, 1999b.

TABLE 8.5. COGENERATION VERSUS SEPARATE PRODUCTION OF ELECTRICITY AND STEAM USING NATURAL GAS COMBINED CYCLES

Rates of activity and costs	Separate production facilities for electricity and steam			Cogeneration facility
	Electricity	Steam	Total	
Power generation rate (megawatts-electric)	400	—	400	400
Process steam production rate, 10-15 bar (megawatts-thermal)	—	400	400	400
Natural gas input rate (terajoules per hour)	2.66	1.77	4.43	3.48
First Law efficiency (percent)	54.1	81.1	64.9	82.8
CO ₂ emission rate (tonnes per hour)	132	88	220	172
Capital investment (millions of dollars)	166	48	214	194
Energy production cost (dollars per thousand kilowatt-hours)				
Capital	6.8	2.0	—	8.0
Operation and maintenance (4 percent of capital cost per year)	2.4	0.7	—	2.8
Fuel	18.0	12.0	—	23.5
Credit for cogenerated steam (at \$14.7 per thousand kilowatt-hours of steam)	—	—	—	-14.7
Total (net) production cost (dollars per thousand kilowatt-hours)	27.2	14.7	—	19.6
Annual cost of energy (millions of dollars)	76.3	41.2	117.5	55.0+41.2
Cost of CO ₂ emissions avoided (dollars per tonne of carbon)	—	—	—	-\$232

Note: Based on calculations by Dale Simbeck, SFA Pacific. Engineering and contingencies and general facilities are each 10 percent of process capital equipment costs. The annual capital charge rate is 11.5 percent. The natural gas price is \$2.70 per gigajoule (see note c, table 8.4). The annual average capacity factor equals 80 percent. The combined cycle plant assumed for both power only and cogeneration applications is the unit with steam-cooled gas turbine blades analysed in table 8.4.

possible for cogeneration to play a far greater role in power generation than is feasible with steam-turbine technology.¹⁶

An example of cogeneration with NGCC technology and equal quantities of electric and steam power is described in table 8.5. For this system, the fuel required is a fifth less and the net cost of electricity is a quarter less per kilowatt-hour than for electricity and heat production in separate facilities. Moreover, net costs for CO₂ emissions reduction are strongly negative at -\$230 per tonne of carbon relative to costs for systems that produce these products singly!

Cogeneration systems based on combined cycles and other high electricity and steam output ratio technologies will typically lead to far more electricity generated than the host factory can consume (Williams, 1978). Entrepreneurs will not be motivated to deploy such technologies unless they are able to sell into the grid electricity produced at fair market rates. Existing electric-sector policies in many countries discourage such sales—for example, electric companies often will not purchase cogenerated power at market rates or will charge exorbitant fees for back-up service. But other countries have adopted policies encouraging cogeneration. In competitive power markets, cogenerators would typically do well (see table 8.5).

A final note: NGCC economic and environmental benefits in power and cogeneration markets are so attractive that countries with constrained natural gas supplies (such as China and India) should consider introducing NGCC plants as anchor users for natural gas

supplies that might be introduced transnationally, using NGCC power generation and cogeneration revenues to underwrite pipeline and other gas infrastructure costs.

Oxygen-blown coal gasification and integrated gasifier combined cycle technologies. Gasification technology makes it possible to extend to coal the economic, thermodynamic, and environmental benefits of combined cycles in the form of IGCC power plants. Gasifiers can be oxygen-blown (O₂) or air-blown. All commercial units are O₂-blown, although some systems based on air-blown units are being demonstrated. The focus here is on systems with O₂-blown gasifiers; systems with air-blown gasifiers are discussed below.

Since the demonstration of IGCC technology with the 94-mega watt-electric Coolwater Project in southern California (1984–89), there has been much progress relating to its commercialisation. Table 8.6 lists five large commercial-scale coal IGCC plants around the world that produce electricity or electricity and steam (cogeneration), as well as nine other large commercial projects that involve gasification of petroleum residues to coproduce electricity with H₂, syngas, or steam.¹⁷ If all the syngas capacity in these 14 plants (9,825 megawatts-thermal) were dedicated to power generation, the equivalent electric generating capacity would be about 5,300 megawatts-electric.

Pollutant emission levels for coal IGCCs can be nearly as low as for NGCCs—much less than for coal steam-electric plants.

Growing concerns about air quality are leading to increased interest in new fuels that have a higher degree of inherent cleanliness than traditional liquid fuels derived from crude oil.

Environmental damage costs associated with emission levels equivalent to those measured at the Buggenum plant in the Netherlands are less than 2 percent of such costs for average coal-fired power plants in the United States and about 10 percent of such costs for coal steam-electric plants equipped with the best available control technology (see table 8.1). Deep reductions in emissions are feasible because pollutants are recovered in concentrated form from the fuel gas (syngas) leaving the gasifier—undiluted by the large amounts of nitrogen from combustion air that are present in flue gases, from which air pollutants are recovered for conventional power plants.

IGCC technology also offers solid waste management advantages. Most direct combustion processes recover sulphur from flue gases as a nonmarketable wet scrubber sludge or as a dry spent sulphur sorbent (the by-product gypsum can be marketed). For such systems, solid wastes are more difficult to handle and market or dispose of, and volumes to be managed are two to three times those for IGCC systems, which recover a marketable elemental sulphur by-product.¹⁸

The cost of electricity for IGCC technology is somewhat higher than for coal steam-electric plants (compare Frame 7F IGCC and steam-electric plant costs in table 8.4)—when credit is not given

for the environmental benefits, which would probably tip the balance decisively in favour of IGCC (see table 8.1). New turbine technology based on the use of steam-cooled turbine blades (Frame 7H technology) could tip the balance slightly in favour of IGCC, even without environmental credits (see table 8.4). But the direct economic benefits are likely to be too small to convince users to shift from familiar technology to any new technology, with all the attendant risks associated with its adoption. The user will take such risks only if forced to (for example, by environmental regulations) or because the economic benefits would be decisive.

O₂-blown coal gasification probably has a better chance of being launched in the market through applications other than power-only—for example, cogeneration. Table 8.7 illustrates the advantages offered by IGCC-based cogeneration. For this system, fuel requirements are reduced one fifth and the net electricity generation cost is reduced one fourth relative to electricity and steam production in separate facilities (as in the corresponding natural gas case—see table 8.5).

Of course, cogeneration strategies can also be pursued with conventional steam turbine technology. However, as illustrated by the calculation in table 8.8 for the same levels of electricity and

TABLE 8.6. LARGE COMMERCIAL GASIFICATION-BASED PROJECTS INVOLVING ELECTRICITY AS PRODUCT OR COPRODUCT

Location	Plant owner	Technology	Syngas out (megawatts-thermal)	Feedstock(s)	Product(s)	Start-up year
Spain	Repsol and Iberola	Texaco	1,654	Vacuum residues	Electricity	2004
Italy	SARLUX srl	Texaco	1,067	Visbreaker residues	Electricity, H ₂	2000
Italy	ISAB Energy	Texaco	982	ROSE asphalt	Electricity, H ₂	1999
France	Total France, EdF, and Texaco	Texaco	895	Fuel oil	Electricity, H ₂	2003
Netherlands	Shell Nederland Raffinaderij BV	Shell	637	Visbreaker residues	Electricity, H ₂	1997
Czech Republic	SUV and EGT	Lurgi Dry Ash	636	Coal	Electricity, steam	1996
United States	Public Service of Indiana	Destec	591	Bituminous Coal	Electricity	1995
Spain	Elcogas SA	PRENFLO	588	Coal, petcoke	Electricity	1997
United States	Motiva Enterprises LLC	Texaco	558	Fluid petcoke	Electricity, steam	1999
Italy	API Raffineria de Ancona S.p.A.	Texaco	496	Visbreaker residues	Electricity	1999
Netherlands	Demkolec BV	Shell	466	Bituminous Coal	Electricity	1994
United States	Tampa Electric Company	Texaco	455	Coal	Electricity	1996
United States	Exxon USA Inc.	Texaco	436	Petcoke	Electricity, syngas	2000
Singapore	Esso Singapore Pty. Ltd.	Texaco	364	Residual oil	Electricity, H ₂	2000

Source: Simbeck and Johnson, 1999.

Encouraging competitive power markets could help put industry on a path to fossil energy with near-zero emissions by helping launch syngas-based polygeneration activities.

process steam generation as in the IGCC case,¹⁹ the fuel savings rate (5 percent) and the reduction in the net cost of electricity (9 percent) are far less than for the IGCC case. Moreover, a comparison of tables 8.7 and 8.8 shows that although there is little difference in efficiency and cost for IGCC and ultrasupercritical steam turbine technologies in producing electricity only, IGCC technology is a markedly better performer in cogeneration applications.

Once gasification technology is established in the market, a continuing stream of innovations can be expected to improve performance and reduce costs—because there are many opportunities (van der Burgt, 1998; Holt, 1999a). One way innovation will take place is by relatively passively incorporating continually improving gas turbine designs into IGCC systems—the benefits of which are illustrated by the shift from air-cooled to steam-cooled gas turbine blades in table 8.4. And if Tophat® turbines are developed (see above), such systems used with gasified coal would be both less capital-intensive and more energy-efficient than current IGCC systems—for example, van der Burgt and van Liere (1996) estimate that with such cycles overall efficiency would increase to about 50 percent.

Specific IGCC-related improvements might also be made. For example, new gasifiers are needed that are well suited for coals with high ash content (typical of many coals in China, India, and South Africa) and for low-rank coals (which are abundant world-wide; see chapter 5), because commercially available entrained-flow gasifiers are not well suited for such coals. Fluidised-bed gasifiers are good candidates for these coals; such gasifiers would also be better suited for handling most biomass and waste as co-feedstocks than are entrained-flow gasifiers. Such technology, in the form of the High Temperature Winkler gasifier, was demonstrated with brown coal at a plant in Berrenrath, Germany, where the syngas was used to produce methanol (Simbeck and others, 1993). An IGCC project based on the High Temperature Winkler gasifier for coal fines has been proposed for construction in the Czech Republic (Holt, 1999b).

One research and development focus is technology to clean gases at high temperatures to reduce thermodynamic losses associated with thermal cycling of gases exiting the gasifier.²⁰ Such technology is being pursued largely because it is necessary for successful development of IGCC systems based on air-blown gasifiers and advanced pressurised fluidised-bed combustion systems (see below). However, hot gas clean-up is not necessary for IGCC systems with O₂-blown gasifiers. The technology is challenging (especially to realise the low emission levels achievable with present cold-gas cleanup), and potential economic benefits are modest even if positive, especially because coal prices are low and declining (Simbeck, 1995; Williams, 1999b).

Despite coal IGCC technical successes, there are few opportunities for deploying the technology in the industrialised world, where electricity demand is growing slowly, and where the NGCC is the technology of choice wherever there is a need for new power supplies and natural

gas is available. The best potential opportunities for IGCC technology are in China and other developing countries where natural gas is not readily available and rapid growth in coal use is expected.

There, IGCC technology could have enormous positive impacts in reducing local and regional air pollution, while substantially improving efficiencies and reducing greenhouse gas emissions. To make initial deployment of IGCC technology economically interesting to such countries, the first installations might be in cogeneration or polygeneration (see below) configurations. As in the case of NGCC cogeneration, the key to unlocking the cogeneration potential offered by IGCC technology is policies that make competitive electricity prices available to these producers for the electricity they wish to sell into electricity grids.

Small engines for cogeneration (reciprocating engines and microturbines). IGCC cogeneration technologies are suitable for deployment at scales of hundreds of megawatts; NGCC cogeneration technologies can be deployed at scales from a few up to hundreds of megawatts. But many small factories, commercial buildings, and apartment buildings would be good candidates for clean, gas-based cogeneration if appropriate technologies were available at scales from less than 100 kilowatts-electric to a few megawatts. Both reciprocating engines and microturbines show promise as near-term technologies for cogeneration at such scales.

From June 1997 through May 1998, world-wide sales of reciprocating engines for stationary power markets totalled about 5,100 units (9.6 gigawatts-electric of total capacity)—a gain of five times from 10 years earlier (Wadman, 1998). More than half of the units will be for continuous service.²¹ Although most units will use oil, 13 percent will use natural gas or will be capable of using dual fuels. Gas applications might expand markedly under increasingly competitive power market conditions.

For spark-ignited engines, shifting to natural gas involves significant de-rating. Compression-ignition engines can also be converted to gas, either by adding a spark plug or by using a liquid spark—a small amount of diesel fuel for ignition. The latter approach is preferable with regard to both first cost and efficiency. Compression-ignition engines with liquid sparks bring to natural gas applications the low cost and high efficiencies of these engines, with much less de-rating. Recent advances have reduced liquid spark requirements for dual-fuel engines to 1 percent of system fuel requirements for larger engines. Such engine generator sets are commercially available at scales of 1–16 megawatts-electric with lower heating value (LHV) efficiencies of 39–42 percent.

Prices for both spark-ignited and dual-fuel engine generator sets (for equipment only) for the capacity range under 1 megawatt-electric typically lie in the range \$425–600 per kilowatt-electric—prices that do not include the costs for heat recovery equipment for cogeneration. Operation and maintenance costs for reciprocating engines are typically significantly higher than for combustion turbines. Reciprocating engines can be used for cogeneration by recovering

TABLE 8.7. COGENERATION VERSUS SEPARATE PRODUCTION OF ELECTRICITY AND STEAM USING COMBINED CYCLE AND COAL GASIFICATION TECHNOLOGIES

Rates of activity and costs	Separate production facilities for electricity and steam			Cogeneration plant
	IGCC plant	Industrial boiler	Total	
Power generation rate (megawatts-electric)	400	—	400	400
Process steam production rate, 10-15 bar (megawatts-thermal)	—	400	400	400
Coal input rate (terajoules per hour)	3.20	1.65	4.85	3.88
First Law efficiency (percent)	45.1	87.2	59.4	74.3
CO ₂ emission rate (tonnes per hour)	274	142	416	333
Capital investment (millions of dollars)	453	197	650	537
Annual energy production cost (millions of dollars per year)				
Capital	52.19	22.69	74.88	61.86
Operation and maintenance (4 percent of capital cost per year)	18.12	7.88	26.00	21.48
Fuel	22.44	11.57	34.01	27.21
Total annual energy cost	92.75	42.14	134.89	110.55
Specific cost of energy (dollars per thousand kilowatt-hours)	For power:	For steam:		For power:
Gross cost	33.1	15.0	—	39.4
Credit for steam coproduct	—	—	—	-15.0
Net cost	33.1	15.0	—	24.4

Note: Based on calculations by Dale Simbeck, SFA Pacific. Engineering plus contingencies are 10 percent of process capital equipment costs; general facilities are 10 percent of process capital equipment costs. The annual capital charge rate is 11.5 percent. The coal price is \$1.00 per gigajoule (see note c, table 8.4). The annual average capacity factor is 80 percent. Both the stand-alone integrated gasifier combined cycle (IGCC) power plant and the cogeneration plant use a Destec O₂-blown coal gasifier coupled to a combined cycle with steam-cooled gas turbine blades.

TABLE 8.8. COGENERATION VERSUS SEPARATE PRODUCTION OF ELECTRICITY AND STEAM USING STEAM TURBINE AND PULVERIZED COAL COMBUSTION TECHNOLOGIES

Rates of PCC activity and costs	Separate production facilities for electricity and steam			Cogeneration plant
	PCC power plant	Industrial boiler	Total	
Power generation rate (megawatts-electric)	400	—	400	400
Process steam production rate, 10-15 bar (megawatts-thermal)	—	400	400	400
Coal input rate (terajoules per hour)	3.39	1.65	5.04	4.68
First Law efficiency (percent)	42.4	87.2	57.1	61.6
CO ₂ emission rate (tonnes per hour)	291	142	433	402
Capital investment (millions of dollars)	453	197	650	612
Annual energy production cost (millions of dollars per year)				
Capital	52.19	22.69	74.88	70.50
Operation and maintenance (4 percent of capital cost per year)	18.12	7.88	26.00	24.48
Fuel	23.77	11.57	35.34	32.82
Total annual energy cost	94.08	42.14	136.22	127.8
Specific cost of energy (dollars per thousand kilowatt-hours)	For power:	For steam:		For power:
Gross cost	33.6	15.0	—	45.6
Credit for steam coproduct	—	—	—	-15.0
Net cost	33.6	15.0	—	30.6

Note: Based on calculations by Dale Simbeck, SFA Pacific. Engineering plus contingencies are 10 percent of process capital equipment costs, as are general facilities. The annual capital charge rate is 11.5 percent. The coal price is \$1.00 per gigajoule (see note c, table 8.4). The average capacity factor is 80 percent. The pulverized coal combustion (PCC) plant is an ultrasupercritical unit for the stand-alone power plant and a sub-critical unit for the cogeneration plant.

There is growing confidence among scientists that underground sequestration of CO₂ will prove to be a major option for mitigating climate-change risks.

both high-quality heat from the engine exhaust and low-quality heat from the engine jacket cooling water. Like gas turbines and combined cycles, reciprocating engines are attractive for such applications because of their high electricity-heat output ratios (see figure 8.1). Some reciprocating engine vendors offer complete cogeneration package systems. Very small-scale systems (under 100 kilowatts-electric) sell in the United States for \$1,500–2,000 per kilowatt-electric. The engines for such systems last only 3–4 years, but replacement engines cost only \$75 per kilowatt-electric.

Air pollutant emissions, especially NO_x, are a concern. Uncontrolled gas engines produce significant CO and non-methane hydrocarbon emissions; however, relatively low-cost oxidation catalytic converters can control such emissions. Most lean-burning, spark-ignited natural gas engines and micro-liquid-spark, dual-fuel engines can achieve NO_x emission of 1.4 grams per kilowatt-hour (100 parts per million by volume at 15 percent O₂)—about 15 times the emission rate for large modern NGCCs with state-of-the-art NO_x controls (see table 8.1). Some vendors now offer systems with half this level of emissions but at an energy efficiency penalty of about 1 percentage point. In some areas (for example, many parts of the United States), NO_x emission regulations will severely limit deployment of reciprocating engines for stationary power markets at scales from 100 kilowatts-electric to 2 megawatts-electric.

Operation of reciprocating engines on town gas (that is, syngas) is also feasible and would be an especially attractive option for natural-gas-poor, coal-rich regions. There town gas could be produced from coal at centralised facilities along with syngas for other poly-generation activities and piped up to 30 kilometres to various distributed cogeneration facilities. The air quality benefits of such gas-based technologies relative to direct coal combustion would be especially important in countries such as China, where coal is used for heating in small, inefficient boilers equipped with little or no air pollution control equipment. However, such systems would not be pollution free. Air emission concerns would be similar to those for reciprocating engines operated on natural gas, except that NO_x emissions might be higher because of higher adiabatic flame temperatures.

Reciprocating engines can also be adapted to small-scale operations in rural areas using either biogas (from anaerobic digesters) or producer gas generated by thermochemical gasification of biomass (see Mukunda, Dasappa, and Srinivasa, 1993; chapters 7 and 10).

Efforts under way to improve reciprocating engine markets for stationary power include the five-year Advanced Reciprocating Engine Systems (ARES) programme—being carried out by a consortium of U.S. manufacturers, the U.S. Department of Energy, the Gas Research Institute, and the Southwest Research Institute. ARES is targeting development of an advanced gas engine with an efficiency of 50 percent (LHV basis) and a NO_x output of 5 parts per million by volume (including catalytic aftertreatment if necessary).

The microturbine is a gas turbine just entering the market for applications at scales less than 100 kilowatts-electric. Its development recently got a boost as a result of its being chosen as a cruise missile engine. One vendor has already launched the technology in the market, and several other aerospace firms are getting ready to market it for stationary power applications. Promoters project that it will do well in new highly competitive distributed power markets (Craig, 1997).

The system involves a low-pressure ratio (3 to 4) gas turbine and compressor mounted on a single shaft.²² The most promising models available are air cooled and have variable speed generators (the output of which is rectified and converted electronically to the alternating-current line frequency), no gear-box, no lubricating oil requirements, and only one moving part. Turbine blades are not cooled, turbine inlet temperatures are modest (840 degrees Celsius), but engine speeds are high—80,000 revolutions a minute or more. Conversion efficiencies with natural gas fuelling are 25 percent (LHV basis) at full power output—far less than for large reciprocating engines but comparable to reciprocating engine generator set efficiencies at scales of tens of kilowatts-electric. Efficiency falls off at part load—to 75 percent of the efficiency at full output when output falls to a third of the peak level (Campanari, 1999).

Although electric efficiencies are not especially high, the technology offers four attractive features:

- Potentially low capital costs in mass production, because of the simple design.
- Low maintenance costs—probably considerably lower than for reciprocating engines, because of the low combustion temperature and the simple design's expected higher reliability.
- Suitability for cogeneration, because all waste heat is of high quality, in the form of hot (230–270 degrees Celsius) air.
- The possibility of low NO_x emissions without stack gas controls.²³

The microturbine faces competition from both reciprocating engines and fuel cells. Maintenance and air quality issues will be important in determining the outcome of competition with reciprocating engines. At scales of hundreds of kilowatts-electric, it will be very difficult for microturbines to compete in efficiency with reciprocating engines. Moreover, if the ARES programme meets its NO_x emissions reduction target, the competition from reciprocating engine technology will be strong at all sizes for which such emissions can be realised.

At the small scales (under 100 kilowatts-electric) that are the focus for market development, the major competition will be from fuel cells—for example, the proton exchange membrane (PEM) fuel cell (see below). Fuel cells will be more efficient in producing electricity from natural gas and will have lower air pollutant emissions. But microturbines will be better performers in providing heat for cogeneration than PEM fuel cells, for which the waste heat quality is low. And microturbines will probably be valued more by utilities as peaking units than PEM fuel cells operated on natural gas, which cannot so readily be dispatched to serve peaking needs.

Microturbines could have great appeal in markets where low-cost gaseous fuels are available—for example, producer gas derived from low-cost crop residues in rural areas of developing countries (chapter 10). They also appear to be well suited for use as bottoming cycles for hybrid cycles that employ pressurised molten carbonate or solid oxide fuel cells as topping cycles (Campanari, 1999; Kartha, Kreutz, and Williams, 1997).

Fuel cells for stationary power and cogeneration. The fuel cell converts fuel into electricity electrochemically, without first burning it to produce heat (Kartha and Grimes, 1994). Fuel cells have attractive features for electricity markets characterised by increasing competition and environmental regulations: high thermodynamic efficiency, low maintenance requirements, quiet operation, zero or near-zero air pollutant emissions without exhaust-gas controls, and high reliability. Fuel cells are likely to be economically viable even in small-scale (100 kilowatts-electric or less) applications. Its properties make it possible to site systems in small, unobtrusive generating facilities close to end users.

Such distributed power sources make cogeneration designs economically attractive and offer the potential of reducing capital outlays for electricity transmission and distribution equipment (Hoff, Wenger, and Farmer, 1996). Low-temperature phosphoric acid fuel cells (PAFCs) and proton exchange membrane fuel cells (PEMFCs) are well suited for combined heat and power applications in small- to medium-scale commercial and residential buildings, providing domestic hot water and space heating and cooling (Little, 1995; Dunnison and Wilson, 1994). Developers of high-temperature molten carbonate fuel cells (MCFCs) and solid-oxide fuel cells (SOFCs) target medium- to large-scale industrial applications.

The PAFC, developed largely in Japan and the United States, is the only commercial fuel cell. Several hundred PAFC power plants (mostly 200-kilowatt-electric natural-gas-fuelled units) are operating. Accumulated experience has demonstrated that fuel cell power plants can be made to operate reliably. Costs are high, however, and whether they can be reduced enough with volume production to make the PAFC widely competitive is uncertain.

Because of recent technological advances, substantial U.S., European, and Japanese activities are seeking to accelerate commercialisation of the PEMFC for residential and commercial building cogeneration markets (Dunnison and Wilson, 1994; Little, 1995; Lloyd, 1999) as well as for transportation (see below). Several companies are developing residential PEMFC combined heat and power systems (Lloyd, 1999). Ballard Generation Systems plans to begin selling 250-kilowatt-electric system for commercial buildings by 2003–04; Plug Power is focussing on smaller (less than 35-kilowatt-electric) units and plans to install the first residential units by 2001.²⁴ In initial applications it is expected that most systems would use mainly existing natural gas infrastructure and, like PAFCs, process natural gas at the point of use in an external fuel processor into an H₂-rich gas the fuel cell can use.

The best chances for making small fuel cells competitive are in markets that value electricity highly (for example, in residential or other buildings, where produced electricity must be less costly than

the retail rate) and where fuel cell waste heat can be used effectively. Space heating and cooling markets are not well matched to PEMFC capabilities; space heating demand is seasonal with enormous variation in the heating season; and the operating PEMFC temperature (80 degrees Celsius) is too low to use waste heat for heat-driven air conditioners.

However, domestic hot water demand often provides a good match—demand is fairly level year-round, and the PEM operating temperature is well suited for domestic hot water. Especially promising opportunities are where the fuel cell is sized to meet the demand for domestic hot water, so that very little waste heat is discarded. If the PEMFC size were increased to meet a larger fraction of the electrical load, it would become more and more difficult to compete, because more and more of the waste heat would have to be discarded, reducing the credit (per kilowatt-hour of electricity) for waste heat utilisation.

The economic prospects are best for apartment buildings, hotels, and hospitals, where a centralised building-scale PEM fuel cell system serves power and hot water needs throughout. It would be more difficult for such systems to compete at the level of single-family dwellings for currently expected PEMFC economies of scale (Kreutz and Ogden, 2000).

The high operating temperatures for MCFCs (600–650 degrees Celsius) and SOFCs (1,000 degrees Celsius) make them well suited for cogeneration, including applications that use the waste heat to operate heat-driven air conditioners. They also offer the option of using directly natural gas or syngas derived through gasification from coal or other feedstocks without an external fuel processor—because these gases can be reformed (using waste heat from fuel cell operation) and shifted on the anode into an H₂-rich gas the fuel cell can easily use—leading, potentially, to higher efficiency, simplified operation, and increasing reliability. (But having an external reformer offers the flexibility of being able to switch relatively easily to operation on alternative fuels.)

The two principal vendors for MCFCs have been Energy Research Corporation and MC Power. Energy Research Corporation units operate at atmospheric pressure with internal reforming; MC Power units operate at pressure but with an external reformer. A 1.8-megawatt-electric demonstration plant based on Energy Research Corporation technology was built and operated on natural gas beginning in April 1996 in Santa Clara, California; a peak efficiency of 40 percent was achieved. Because of various difficulties, the unit was operated for only 4,000 hours and was dismantled in March 1997. In March 1999 Energy Research Corporation put into operation a 250-kilowatt-electric demonstration unit at its Danbury, Connecticut, headquarters. In 1997 MC Power operated a 250-kilowatt-electric cogeneration unit at the Naval (now Marine Corps) Miramar Air Station in San Diego, California. Unable to raise new funding for research and development, MC Power went out of business in March 2000.

SOFCs offer the potential for high efficiency, low cost, and potentially long operating lifetimes (Bakker, 1996). The main uncertainties concern manufacturing costs and durability in operation as a result of the fact that SOFCs are made of ceramics. Although the cost of the

materials in the ceramics is inherently low (\$7–15 per kilowatt-electric; Goldstein, 1992), fabrication of ceramics is difficult and costly. Moreover, there are risks that the ceramic components will develop cracks during operation as a result of thermal cycling.

Siemens Westinghouse, the leading SOFC developer, has focussed on a tubular design and has deployed seven fully integrated, automatically controlled, packaged SOFC systems as experimental field units. The largest of these is a 100-kilowatt-electric natural-gas-fuelled cogeneration system deployed in the Netherlands in early 1998. The system has realised extremely low pollutant emissions—0.2 parts per million by volume of NO_x and undetectable levels of sulphur dioxide (SO₂), CO, and unburned hydrocarbons (Veyo, 1998).

The tubular design facilitates manufacture and realisation of properly operating seals, but it is uncertain how low costs can become in mass production. Planar designs that operate at lower temperatures (800 degrees Celsius)²⁵ seem promising with regard to both high efficiency (55–70 percent on natural gas, LHV basis) and capital cost in mass production (\$700–800 per kilowatt-electric at a scale of 500 kilowatts-electric; Chen, Wright, and Krist, 1997). But such designs require considerable more research and development.

In the 1970s and 1980s it was expected that high-temperature fuel cells would eventually be able to compete with conventional power generating technologies at a wide range of scales—including large central-station power plants as well as cogeneration plants of all sizes. But the enormous success of gas turbines and combined cycles dampened the prospects for large-scale fuel cell applications

during the early 1990s—when it became apparent that the marginal efficiency gains offered by fuel cells over combined cycles would not be able to justify the expected higher capital costs—except in small-scale operations (1 megawatt-electric or less). However, since the early 1990s two developments have once more brightened the prospects for high-temperature fuel cells for larger-scale installations.

The first is a hybrid concept that offers both higher efficiency and lower capital cost. A hybrid would be made up of a high-temperature fuel cell topping cycle and a gas turbine or a steam turbine or gas turbine–steam turbine combined cycle bottoming cycle. A high-temperature fuel cell operated on natural gas or syngas will utilise only 80–90 percent of the gas energy. The chemical energy remaining in the hot anode exhaust gases can be burned to generate more electricity in a bottoming cycle. Modelling carried out at the Electric Power Research Institute indicates that a 56 percent efficient natural-gas-fuelled SOFC combined with a regenerative gas turbine bottoming cycle could lead to a system efficiency of 71 percent (Bakker, 1996)—efficiencies well above the levels that can be realised with gas turbine–steam turbine combined cycles. Because the cost per kilowatt-electric of the bottoming cycle will typically be less than the cost per kilowatt-electric for the fuel cell itself, the overall capital cost for the hybrid will be less than for a pure-bred fuel cell.

The second new development is related to the fact that pressurised high-temperature fuel cells offer an option for low-cost CO₂ recovery and disposal as a response to climate change concerns. The concept is related to the fact that CO₂ is available at high partial

BOX 8.2. DEEP OCEAN SEQUESTRATION OF ANTHROPOGENIC CARBON DIOXIDE

The ocean, containing 40,000 gigatonnes of carbon (relative to 750 GtC in the atmosphere), represents the largest potential sink for anthropogenic CO₂; disposing in the ocean of an amount of CO₂ that would otherwise lead to a doubling of the atmosphere's content would thus increase the ocean concentration by less than 2 percent. On a 1,000-year time scale, more than 90 percent of today's anthropogenic emissions will be transferred to the oceans through a slow, natural process. The basic idea of ocean sequestration of CO₂ is to inject CO₂ directly into the deep ocean to accelerate this process and reduce both peak atmospheric CO₂ concentrations and their rate of increase.

For a large fraction of injected CO₂ to remain in the ocean, injection must be at great depths. This is because CO₂ would be a gas above 800 metres and a liquid below 800 metres. Liquid CO₂ is negatively buoyant relative to ordinary seawater only below 3,000 metres. Liquid CO₂ is negatively buoyant relative to seawater saturated with CO₂ only below 3,700 metres. And at injection depths of about 500 metres or more, a CO₂-seawater

mixture (depending on the relative compositions) can lead to formation of a CO₂ hydrate, which is about 10 percent denser than seawater.

A consensus is developing that the best near-term strategy would be to discharge CO₂ at depths of 1,000–1,500 metres, which can be done with existing technology. A major uncertainty that requires more research for clarification relates to the sequestration efficiency (the fraction of the CO₂ that remains in the ocean) of injection at such depths (see, for example, Brewer and others, 1999). Another approach, aimed at maximising sequestration efficiency, is to inject liquid CO₂ into a deep sea-floor depression, forming a stable deep lake at a depth of 4,000 metres—an approach that is technologically challenging with current technology. A simple and feasible but very costly option is to release dry ice from a surface ship. Another approach is to create a dense CO₂-seawater mixture at a depth of 500–1,000 metres and cause it to form a sinking-bottom gravity current—an approach that has raised many environmental impact concerns.

On a global scale, both climate change

and other environmental impacts of ocean disposal (for example, increased ocean acidity) are positive. But on a local scale, there are considerable environmental concerns arising largely as a result of the increased acidification near the points of injection—for example, impacts on non-swimming marine organisms residing at depths of 1,000 metres or more.

Japan has the world's most active ocean sequestration research programme, led by the Research Institute of Innovative Technology for the Earth and the Kansai Environmental Engineering Centre, and funded at an annual level of more than 10 million dollars.

Although the deep ocean has been the most-discussed option for CO₂ disposal, much more research is needed to better understand the security, costs, and environmental impacts of various ocean disposal schemes (Turkenburg, 1992). In addition, the viability of ocean storage as a greenhouse gas mitigation option hinges on social and political as well as technical, economic, and environmental considerations. The public is generally cautious regarding ocean projects.

Source: Herzog, 1999b.

A fierce global competition is underway to accelerate the development of fuel cell vehicles.

pressure in the anode exhaust of pressurised SOFCs or MCFCs in highly concentrated form. To illustrate, consider operation of a pressurised SOFC on syngas (mainly CO and H₂) derived from coal through O₂-blown gasification. Both the CO and the H₂ react in the anode directly with O₂ (transported across the electrolyte from the cathode as an oxygen ion) to form CO₂ and H₂O. If the 10–20 percent of the unconverted CO and H₂ exiting the anode is then burned in O₂ for use in a bottoming cycle,²⁶ the gaseous product will be a mixture of CO₂ and H₂O, from which the H₂O can easily be removed by cooling and condensation. Moreover, if the bottoming cycle is a steam turbine, the CO₂ can be recovered for disposal at relatively high pressure, leading to low costs for further pressurising the CO₂ to the level needed for disposal. Recognising the value of this strategy, Shell announced in July 1999 plans to develop and market with Siemens Westinghouse SOFC technology capable of disposing of CO₂ in this manner.²⁷

Decarbonisation and carbon dioxide sequestration strategies for power generation systems. Because of climate change concerns, increasing attention has been given in recent years to strategies for extracting energy from fossil fuels without releasing CO₂ into the atmosphere. The issues involved concern the capacity, security, and cost of alternative CO₂ disposal options and the costs of separating the CO₂ from fossil energy systems and preparing it for disposal.

The options for CO₂ sequestration include both the deep ocean and geological reservoirs. Although ocean disposal has received the most attention (box 8.2), large uncertainties in its prospects (Turkenburg, 1992) have led to a shift of focus in recent years to give more attention to geological (underground) storage of CO₂, in depleted oil and natural gas fields (including storage in conjunction with enhanced oil and gas recovery), in deep coal beds (in conjunction with coal bed methane recovery), and in deep saline aquifers.

CO₂ injection for enhanced oil recovery (Blunt, Fayers, and Orr, 1993), enhanced gas recovery (van der Burgt, Cantle, and Boutkan, 1992; Blok and others, 1997), and enhanced recovery of deep coal bed methane (Byrer and Guthrie, 1999; Gunter and others, 1997; Stevens and others, 1999; Williams, 1999a) might become profitable focuses of initial efforts to sequester CO₂. Enhanced oil recovery using CO₂ injection is well-established technology; one project that began in 2000 in Saskatchewan, Canada, is injecting yearly up to 1.5 million tonnes of CO₂, which is transported 300 kilometres to the injection site from a synthetic natural gas plant in North Dakota (see below).

Sequestration in depleted oil and gas fields is generally thought to be a secure option if the original reservoir pressure is not exceeded (van der Burgt, Cantle, and Boutkan, 1992; Summerfield and others, 1993). One estimate of the prospective global sequestering capacity of such reservoirs associated with past production plus proven reserves plus estimated undiscovered conventional resources is 100 GtC for oil fields and 400 GtC for gas fields

(Hendriks, 1994). Other estimates are as low as 40 GtC for depleted oil fields and 90 GtC for depleted gas fields, plus 20 GtC associated with enhanced oil recovery (IPCC, 1996a). The range is wide because reservoir properties vary greatly in their suitability for storage, and because oil and gas recovery may have altered the formations and affected reservoir integrity. Much of the prospective sequestering capacity will not be available until these fields are nearly depleted of oil and gas.

Deep aquifers are much more widely available than oil or gas fields. Such aquifers underlie most sedimentary basins, the total areas of which amount to 70 million square kilometres (two-thirds onshore and one-third offshore), more than half the 130-million-square-kilometre land area of the inhabited continents. Some sedimentary basins offer better prospects for CO₂ storage than others (Hitchon and others, 1999; Bachu and Gunter, 1999). To achieve high storage densities, CO₂ should be stored at supercritical pressures (more than about 75 times atmospheric pressure), which typically requires storage at depths greater than 800 metres. The aquifers at such depths are typically saline and not effectively connected to the much shallower (typically less than 300-metre) sweet-water aquifers used by people. If aquifer storage is limited to closed aquifers with structural traps, the potential global sequestering capacity is relatively limited—about 50 GtC (Hendriks, 1994), equivalent to less than 10 years of global CO₂ production from burning fossil fuel at the current rate.

However, if structural traps are not required for effective storage, potential aquifer storage capacity might be huge; estimates range from 2,700 GtC (Omerod, 1994) to 13,000 GtC (Hendriks, 1994). For comparison, estimated remaining recoverable fossil fuel resources (excluding methane hydrates) contain about 5,600 GtC (see table 5.7). A growing body of knowledge indicates that many large horizontal open aquifers might provide effective storage²⁸ if the CO₂ is injected far enough from reservoir boundaries that it dissolves in the formation water or precipitates out as a mineral as a result of reactions with the surrounding rock before migrating more than a few kilometres towards the basin boundaries (Bachu, Gunter, and Perkins, 1994; Gunter, Perkins, and McCann, 1993; Socolow, 1997). The relatively new idea that large horizontal aquifers can provide effective sequestration has contributed to growing confidence among scientists that underground sequestration of CO₂ will prove to be a major option for mitigating climate-change risks (Holloway, 1996; Socolow, 1997; PCAST Energy Research and Development Panel, 1997).

Experience with aquifer disposal will be provided by two projects involving injection into nearby aquifers of CO₂ separated from natural gas recovered from CO₂-rich gas reservoirs. One is a Statoil project begun in 1996 to recover 1 million tonnes of CO₂ a year from the Sleipner Vest offshore natural gas field in Norway

(Kaarstad, 1992). The second, which will commence in 10 years, will involve the recovery of more than 100 million tonnes a year (equivalent to 0.5 percent of total global emissions from fossil fuel burning) from the Natuna natural gas field in the South China Sea (71 percent of the reservoir gas is CO₂) (IEA, 1996).

Extensive historical experience with underground gas storage contributes to the growing scientific confidence in the reliability of geological reservoirs for storing CO₂. And regulations that have been evolving for underground gas storage provide a good basis for defining the issues associated with formulation of regulations for CO₂ storage (Gunter, Chalaturnyk, and Scott, 1999).

More research, field testing, modelling, and monitoring are needed to narrow the uncertainties relating to CO₂ storage in geological reservoirs. From a policy perspective, it is particularly important to understand better potential effective storage capacities on a region-by-region basis so that energy and environmental planners will have a better understanding of the overall potential for fossil fuel decarbonisation with CO₂ sequestration as an option for dealing with climate change. Getting such important information is not likely to be especially costly. For example, Stefan Bachu of the Alberta Research Council

has estimated that obtaining a reasonable estimate of the geological CO₂ storage capacity of Canada would cost \$14 million (Gunter, 1999). The cost is relatively low because geological surveys have collected an enormous amount of relevant data during the past 100 years, and many more relevant data from industrial sources are available from regulatory bodies.

Public acceptability issues are paramount. Fuel decarbonisation with CO₂ sequestration is unfamiliar to most people as a strategy for dealing with the climate change challenge. What will public attitudes be? The scientific community has a major responsibility to inform the public debates on the various issues relating to safety and environmental impacts. Much can be learned from both natural events (Holloway, 1997) and from the extensive historical experience with use of CO₂ injection for enhanced oil recovery and with underground gas storage (Gunter, Chalaturnyk, and Scott, 1999). But more research is needed to clarify the issues.

An optimistic note on which to end this discussion: in the sections that follow, it will be shown that those advanced fossil energy technologies offering the potential for CO₂ disposal at the least costs are also characterised by near-zero emissions of air pollutants.

TABLE 8.9. ALTERNATIVE TECHNOLOGIES FOR REDUCING CO₂ EMISSIONS FROM 400-MEGAWATT-ELECTRIC COAL PLANTS

Technology	Efficiency (percent, HHV)	Capital cost (dollars per kilowatt)	Generation cost (dollars per thousand kilowatt-hours)	O ₂ requirements (tonnes per hour)	CO ₂ emissions (grams of carbon per kilowatt-hour)	Cost of avoiding CO ₂ emissions (dollars per tonne of carbon)
Ultrasupercritical pulverised coal steam turbine plant						
Reference, CO ₂ vented	43.1	1,114	33.0	0	196	—
CO ₂ recovery from flue gasses	34.3	1,812	52.2	0	36.8	134
O ₂ firing, CO ₂ recovery from flue gasses	32.0	1,661	52.8	339	0	111
Pressurised fluidised-bed combustion plant						
Reference, CO ₂ vented	43.1	1,114	33.0	0	196	—
O ₂ firing, CO ₂ recovery from flue gasses	35.4	1,675	51.6	307	0	104
Integrated gasifier-combined cycle plant						
Reference, CO ₂ vented	45.9	1,114	32.5	80	184	—
Cold CO ₂ recovery from synthesis gas	36.1	1,514	47.9	108	23.9	96
Warm CO ₂ recovery from synthesis gas (advanced technology)	41.5	1,466	44.5	94	20.4	73
H₂-O₂ Rankine cycle plant: Cold CO₂ recovery from synthesis gas (advanced technology)	40.5	1,622	48.4	259	6.1	90
Solid oxide fuel cell (SOFC) plant						
H ₂ -fueled SOFC-gas turbine-steam turbine plant, warm CO ₂ recovery from synthesis gas (advanced technology)	45.7	1,461	43.3	85	19.1	65
SOFC-steam turbine plant, CO ₂ recovered from anode exhaust burned with O ₂ (advanced technology)	44.3	1,427	43.1	114	6.8	60

Note: Based on calculations by Dale Simbeck, SFA Pacific. Engineering and contingencies are 10 percent of process capital equipment costs; general facilities are 10 percent of process capital equipment costs. The annual capital charge rate is 11.5 percent. The coal price is \$1.00 per gigajoule. The annual average capacity factor is 80 percent. All options involving CO₂ separation and disposal include the cost of compressing the separated CO₂ to 135 bar plus a cost of \$5 per tonne of CO₂ (\$18 per tonne of carbon) for pipeline transmission and ultimate disposal.

The air pollution emissions issue will be in centre stage during the competition between fuel cell and hybrid internal combustion engine vehicles to be car of the future.

People are likely to be more willing to accept fuel decarbonisation with CO₂ sequestration as a major energy option if the technology also offers near-zero emissions than if they view it as a way to sustain a dirty energy system—away from which they would rather evolve.

Table 8.9 presents performance and cost calculations (developed in a self-consistent manner across options) for eight alternative technologies and strategies for CO₂ removal and disposal for coal-fired power systems—variants of calculations developed earlier by Simbeck (1999c). Four options are based on current or near-term (before 2005) technologies. The other four (labelled advanced technology) require considerable technological development. The H₂-O₂ Rankine cycle plant involves producing H₂ through coal gasification and burning it with O₂ in a Rankine cycle—a technology proposed by Westinghouse researchers (Bannister and others, 1996; Bannister, Newby, and Yang, 1997, 1998). The turbine in this system looks like a gas turbine in the high-pressure stages but a steam turbine at the condensing end—because the combustion of H₂ in O₂ leads to the production of only steam. If there were a market for the turbine used in this system, it could probably be developed in 2010–20. The SOFC options require commercialisation of SOFC power technology, which developers expect to take place before 2010. The two warm gas recovery options require the development of relatively challenging advanced gas separation technologies, which could be commercial by 2015.

The CO₂ separation and disposal options are compared with three reference technologies for power generation without CO₂ removal and disposal: an ultrasupercritical steam-electric plant (see below), a pressurised fluidised-bed combustion plant (see below), and an IGCC plant (the Frame 7H option described in table 8.4). Identical capital costs are assumed for these reference plants: Not only is this a reasonable approximation, but also this assumption helps clarify cost differences for CO₂ separation and disposal among alternatives.²⁹ The cost of avoided CO₂ emissions for each case is calculated relative to the least costly option in the table (the reference IGCC case, with CO₂ venting).

The first CO₂ recovery option involves CO₂ scrubbing from the stack gases of an ultrasupercritical steam-electric plant using an amine solution (flue gas scrubbing). The cost of avoiding CO₂ emissions and the power generation cost penalty are relatively high (\$134 per tonne of carbon and \$0.020 per kilowatt-hour), largely because of the high cost penalties associated with recovering CO₂ from the stack gases, where its concentration and partial pressure are low (15 percent and 0.15 bar, respectively).

The second option uses atmospheric pressure O₂ rather than air as oxidant, and recycles the separated CO₂ back to the ultra supercritical steam plant combustor. This strategy greatly increases the partial pressure of CO₂ in the flue gas. Cost penalties are comparable to those for flue gas recovery because of the large quantities of costly O₂ required. The third option is for a pressurised fluidised-bed

combustion unit that uses pressurised O₂ as the oxidant instead of pressurised air. This further increases the CO₂ partial pressure in the flue gas and reduces CO₂ removal costs; however, because pressurised O₂ is more costly than O₂ at atmospheric pressure, the savings relative to the ultra-supercritical steam-electric cases is modest.

The five remaining options—which have avoided CO₂ emission costs that are much lower than for the first three—are for systems involving O₂-blown gasifiers. The first, cold CO₂ recovery from synthesis gas for IGCC plants, is based on existing CO₂ recovery technology. This option starts with gasification to produce syngas (mainly CO and H₂). The syngas is reacted with steam in shift reactors to convert CO into H₂ and CO₂. Subsequently, CO₂ is separated out for disposal, and the H₂-rich fuel gas is burned in the gas turbine combustor.³⁰ This option has the least cost penalties of all the near-term options (\$96 per tonne of carbon and \$0.015 per kilowatt-hour). The low cost is realised largely because, when CO₂ is recovered from the shifted syngas in an IGCC, its concentration is high (33 percent), as is its partial pressure (more than 10 bar). The advanced technology option labelled warm CO₂ recovery from synthesis gas for IGCC plants, could—if successfully developed—reduce avoided CO₂ emission costs by a fourth relative to the cold gas recovery option. For the advanced technology option labelled cold CO₂ recovery from synthesis gas for an H₂-O₂ Rankine cycle, the H₂-O₂ turbine capital cost is expected to be relatively low, and the efficiency of converting H₂ into electricity high. However, the system requires large quantities of costly O₂. As a result this system would not improve on the least costly current technology option—cold CO₂ recovery from synthesis gas for an IGCC plant.

The last two entries depend on the successful development of SOFC technology. The penultimate entry also depends on the success of warm-gas separation technology. The last entry is the least costly of the advanced technology options—involving recovery of CO₂ at pressure from the anode exhaust (see above). This technology would provide electricity from coal with only 3 percent of the CO₂ emissions for the conventional coal steam-electric plant at a generation cost of \$0.043 per kilowatt-hour, for an avoided CO₂ emission cost of \$60 per tonne of carbon.³¹ This is about \$0.01 per kilowatt-hour more than the cost of electricity from a coal-fired power plant today with no CO₂ removal and sequestration. This is consistent with findings by a group at the Massachusetts Institute of Technology (MIT) Energy Laboratory that, with advanced IGCC technology (expected to be commercially available by 2012), the cost penalty for decarbonisation and sequestration would be less than \$0.01 per kilowatt-hour (Herzog, 1999a).

An implicit assumption for these calculations is that a new coal plant is the least costly option—for example, the calculations are appropriate for coal-rich, natural-gas-poor countries. If natural gas were available, the cost of CO₂ emissions avoided by CO₂ recovery and disposal at a coal plant would typically be higher. Table 8.10

TABLE 8.10. THE COST OF ELECTRICITY FROM COAL AND NATURAL GAS WITH AND WITHOUT CO₂ SEQUESTRATION, BASED ON NEAR-TERM TECHNOLOGIES

Rates of activity and costs	USC steam ^a		Natural gas-fired combined cycle ^b		Coal IGCC ^b	
	No	No	Yes	Yes	No	Yes
CO ₂ sequestered?	No	No	Yes	Yes	No	Yes
CO ₂ separation method	—	—	FGS ^c	NG→H ₂ ^c	-	Syngas→H ₂
Efficiency (percent, HHV basis)	43.1	54.0	45.7	42.2	45.9	36.1
Emission rate (grams of carbon per kilowatt-hour)	196	90	15.7	11.6	184	23.9
CO ₂ disposal rate (grams of carbon per kilowatt-hour)	—	—	91	104	—	210
Capital cost (dollars per kilowatt)	1,114	416	907	918	1,114	1,514
Generation cost^d (dollars per thousand kilowatt-hours)						
Capital	18.30	6.83	14.90	15.08	18.30	24.87
Operation and maintenance	6.35	2.37	5.17	5.24	6.35	8.64
Fuel	8.35•P _C	6.67•P _{NG}	7.88•P _{NG}	8.53•P _{NG}	7.84•P _C	9.97•P _C
CO ₂ disposal (at \$5 per tonne of CO ₂) ^e	—	—	1.66	1.90	—	4.38
Total generation cost ^f	24.65+8.35•P _C	9.20+6.67•P _{NG}	21.73+7.88•P _{NG}	22.22+8.53•P _{NG}	24.65+7.84•P _C	37.89+9.97•P _C
at 1998 U.S. fuel prices	34.6	23.8	39.5	41.5	34.0	49.8
at 2020 U.S. fuel prices	32.0	29.7	45.9	48.4	31.6	46.7
Avoided CO₂ emissions cost, relative to same technology without separation and disposal (dollars per tonne of carbon, for 2020 U.S. fuel prices)^g	—	—	219	236	—	96
Electricity cost (dollars per thousand kilowatt-hours), for 2020 U.S. fuel prices and \$219 tax per tonne of carbon	74.9	49.3	49.3	51.0	71.8	51.9

a. For a 400-megawatt-electric, pulverised-coal, ultrasupercritical steam-electric plant; see table 8.9. b. Based on an analysis developed in Simbeck (1999c); coal IGCC technologies are the same as for reference and cold CO₂ recovery cases in table 8.9. c. FGS = flue gas scrubber; for NG→H₂ case, natural gas (NG) is converted to H₂ using an O₂-autothermal reformer. d. Annual capital charge rate = 11.5 percent; annual operation and maintenance cost = 4 percent of capital cost; P_C = coal price, P_{NG} = natural gas price (dollars per gigajoule). e. To account for pipeline transmission and ultimate disposal costs. f. For 1998: P_C = \$1.19 per gigajoule; P_{NG} = \$2.26 per gigajoule, average U.S. prices for electric generators (EIA, 1999b). For 2020: P_C = \$0.88 per gigajoule; P_{NG} = \$3.07 per gigajoule, average U.S. prices projected for electric generators in the Energy Information Administration's reference scenario (EIA, 1998a). g. Avoided cost = (generation cost with sequestration minus generation cost without sequestration) divided by (emissions without sequestration minus emissions with sequestration).

presents calculations, also based on Simbeck (1999c), that illustrate the situation for near-term (before 2005) technology when NGCCs and coal IGCCs are competing, and emission reductions of 90 percent are considered for both. The IGCC option is the IGCC with cold CO₂ recovery from table 8.9. For NGCCs, two CO₂ separation-and-disposal options are considered. The least costly option involves scrubbing CO₂ from flue gases.

Even though removal of twice as much CO₂ per kilowatt-hour is required for the IGCC case, the cost penalty per kilowatt-hour of CO₂ separation and disposal is not greater than for the NGCC case. This counterintuitive result arises because scrubbing CO₂ from NGCC *flue gases* is more capital- and energy-intensive than recovering CO₂ from IGCC *fuel gas*. H₂ could also be made from natural gas by reforming. But as shown, with current technology doing so would not be less costly than scrubbing flue gas, because the gain in

reduced cost by avoiding the flue gas scrubber would be offset by the added costs for reformer and shift reactors.³²

One result of the analysis shown in table 8.10 is that—for the CO₂ recovery-and-disposal cases and 2020 U.S. fuel prices—the costs of generating electricity from natural gas and coal are about the same (\$0.046–0.047 per kilowatt-hour). The findings of Herzog (1999a)—who considered improvements in the technologies relative to the cases presented in table 8.10 and which he projected would be commercial by 2012—indicate that this cost parity between coal and natural gas systems is likely to hold even when technological improvements are taken into account for natural gas as well as coal technologies.³³

The last row in table 8.10 shows the electric generating costs with a carbon tax high enough to induce NGCC power generators (as well as coal IGCC power generators) to separate and dispose of CO₂.

This tax (\$220 per tonne of carbon) is 2.3 times the carbon tax needed if there were no competition from natural gas. The cost of power generation (including the carbon tax) would be \$0.05 per kilowatt-hour for all options except coal plants without CO₂ separation and disposal. With the advanced technologies considered by Herzog (1999a), the carbon tax needed to induce CO₂ recovery and disposal for NGCC plants would be less (\$170 versus \$70 per tonne of carbon for coal IGCC plants).

The technologies considered here for CO₂ recovery and disposal do not exhaust the possibilities. A class of advanced technologies that offers considerable promise of increasing system efficiency and reducing CO₂ removal costs for both natural gas and coal power systems involves using inorganic membranes that are highly permeable to H₂ but not other gases. If such membranes were applied to natural gas combined cycles, they might make it possible to carry out simultaneously steam reforming, water gas shifting, and H₂ separation in a single vessel. Continuous H₂ removal by the membrane might make it feasible to carry out reforming reactions at temperatures low enough that gas turbine exhaust heat could be used to provide the needed heat (Moritsuka, 1999). (The application of such technologies to coal systems is discussed below.)

Advanced fuels for transportation and other applications

This section discusses the prospects for using advanced fuels to satisfy the sustainable development objectives of keeping fuels affordable, increasing energy security, and evolving towards near-zero emissions of both air pollutants and greenhouse gases. The focus here is mainly on transport fuels that can be derived from syngas, with some reference to synthetic cooking fuels. (The prospects for synthetic fuels derived by direct coal liquefaction are discussed in the next section below.) This discussion of transport fuels is presented in the context of the associated vehicle technologies and the challenges posed by various fuel-vehicle combinations.

Oxygenated fuels: the current focus. U.S. fuel improvement efforts have focussed on reducing levels of benzene (an extremely carcinogenic aromatic compound) in gasoline and on adding oxygenates such as methyl tertiary butyl ether (MTBE) to gasoline to reduce CO emissions and inhibit photochemical smog formation, while maintaining octane ratings that would otherwise fall as a result of lead removal. Although oxygenates are effective in reducing CO emissions and maintaining octane rating, they offer negligible benefits in reducing atmospheric ozone formation (Calvert and others, 1993).

MTBE derived from methanol (MeOH) is widely added to gasoline in volumetric quantities up to 15 percent to help control CO emissions. About 30 percent of the U.S. population lives in areas where MTBE is in regular use; U.S. production levels reached more than 6 million tonnes in 1995. But MTBE use in the future is likely to be severely limited. In July 1999 the U.S. Environmental Protection Agency announced that it would act to greatly reduce the use of MTBE in reformulated gasoline, and in December 1999

the California Air Resources Board banned the use of MTBE in reformulated gasoline in California beginning in 2003.

The shift from MTBE is taking place not only because its air quality benefits appear to be marginal, but also because it is extremely soluble and persistent in water, and humans may be experiencing prolonged exposure to it through tap water. Although it is not especially harmful to humans at typical exposure levels, it imparts a bitter taste and solvent-like odour to water that it contaminates—and human taste and odour thresholds are extremely low (40 parts per billion). MTBE enters drinking water through leaks in gasoline tanks or spills into surface water or groundwater. Although tank leaks also release benzene and many other aromatic and non-aromatic compounds, MTBE tends to migrate faster than other contaminants and is likely to be at the leading edge of a travelling plume (Stern and Tardiff, 1997).

Alcohols. Alcohols (methanol and ethanol) have attracted considerable interest as alternative automotive fuels, especially in Brazil and the United States. The production from biomass of ethanol through biological processes and methanol through thermochemical processes that begin with thermochemical gasification are discussed in chapter 7.

MeOH can be produced from any carbonaceous feedstock through processes that begin with syngas production—for example, from natural gas through steam reforming, from coal through O₂-blown gasification, or from biomass through steam gasification (Williams and others, 1995). Nearly all MeOH is produced from low-cost sources of natural gas, which are often available at remote sites where a natural gas pipeline infrastructure has not been established. Because MeOH is an easily transported liquid, its production from remote gas sources provides a means of exploiting such resources. Most MeOH is used as a chemical feedstock. Its use as a fuel has mainly been for MTBE manufacture. In addition, modest amounts have been used directly in blends with gasoline for cars. With conventional technology, the cost of making it from coal is much greater than from natural gas, because the added capital cost for gasification generally cannot be adequately compensated for by the lower cost of coal relative to natural gas.

Although the use of alcohol fuels in vehicles with internal combustion engines can lead to reduced oil dependence, it is now generally believed that alcohol fuels—especially when blended with gasoline and used in flexible-fuel internal combustion engine vehicles—offer little or no air quality advantages other than lower CO emissions (Calvert and others, 1993). Moreover, reformulated gasoline can meet or surpass the air pollution reductions of alcohol-gasoline blends (CTOFM, 1991). With MeOH, CO emissions would be reduced, and emissions of volatile organic compounds would be less problematic than for gasoline. NO_x emissions would probably not be reduced, however. Ethanol offers fewer air quality benefits than MeOH and may produce more ozone per carbon atom (Calvert and others, 1993).

Emissions from alcohol-fuelled fuel cell vehicles would be a tiny fraction of the emissions from gasoline-fuelled internal combustion engine vehicles. Moreover, the use of alcohols in fuel cell vehicles would lead to marked improvements in fuel economy relative to their use in internal combustion engine vehicles. Several auto manufacturers plan to launch fuel cell vehicles in the market using MeOH as fuel (see below).

If MeOH were to become widely used as an energy carrier for transportation, a concern is its toxicity through direct ingestion, absorption through the skin, or ingestion as a result of drinking methanol-contaminated groundwater.³⁴ Detailed risk assessments indicate that toxicity is not likely to be a significant concern in routine use, although it might be problematic for accidents involving large spills (Health Effects Institute, 1987). In the case of groundwater contamination, risks are generally much less than for MTBE, because in most situations MeOH would degrade quickly. But oil companies—having been burned by recent decisions to ban MTBE after having made enormous investments in MTBE production, and concerned about liability issues relating to MeOH's toxicity—might be reluctant to make major investments in MeOH, especially if there are promising non-toxic, clean alternative fuels.

The need for a policy framework for transport fuels and engines. The discussions of MTBE and alcohol fuels highlight the lack of a coherent, consistent policy framework for developing advanced fuels and engines for transportation. Closely related to these discussions is the emerging view that environmental regulations are not focussed on the most important pollutants.

Recent studies indicate that by far the greatest costs associated with health impacts arising from transport-related air pollutant emissions are those from fine particles (chapter 3)—both those emitted from vehicles directly and nitrate particles formed in the atmosphere from NO_x emissions. Spadaro and Rabl (1998) estimate that relative to the costs associated with fine particles the health costs posed by CO emissions are negligible, and health costs associated with ozone formation are modest (see table 8.2). It thus appears that concerns about NO_x and particulate emissions will shape future technological choices for fuels and engines.

Besides the lack of a properly focused environmental policy, low oil prices and gasoline taxes also provide no market incentive in the United States for fuel-efficient cars. There the trend has been towards an increasing market share of fuel-guzzling sport utility vehicles—exacerbating concerns about energy supply security and emissions of air pollutants and CO₂.

One auspicious development from Japan is recent commercialisation of a gasoline-fuelled car powered by a hybrid of an internal combustion engine and a battery. This hybrid offers fuel economy twice that of conventional cars with internal combustion engines. Their high efficiency and the fact that they can be operated most of the time near their optimal operating points make it feasible to achieve much lower emissions with gasoline hybrids than with conventional internal combustion engine vehicles.

Advanced hybrid vehicles are being developed under the U.S. Partnership for a New Generation of Vehicles (PNGV), a government-

industry initiative that seeks to develop production-ready prototypes that will get 80 miles a gallon (34 kilometres a litre) by 2004 (NRC, 1998). Because this goal is three times the fuel economy of existing cars, emphasis is being given to hybrids based on compression ignition engines (specifically, compression-ignition direct-injection, or CIDI, engines), which are more fuel efficient than spark-ignited hybrids. The CIDI hybrid and the fuel cell car (see below) are the leading contenders to meet PNGV goals for the car of the future.

But the ambitious PNGV research and development programme is not complemented by incentives to introduce such fuel-efficient vehicles into the market. Moreover, unlike the situation with gasoline hybrids, there is no strong air quality driver for advancing CIDI hybrids. To the contrary, air pollution mitigation challenges are far more daunting for compression-ignition than for spark-ignited engines (see table 8.2). In early 2000 DaimlerChrysler introduced a prototype CIDI hybrid car developed under the PNGV that got 72 miles a gallon (30.6 kilometres a litre). Although this car met the air quality standards in effect in 1993, when the PNGV was launched, the current design cannot meet the standards that will be in effect in 2005, when such cars might first be produced on a commercial basis.

There is also a need for better coordination between development activities for fuels and engines. There are needs not only for new fuels but also new engines that are optimised for these fuels.

Syngas-derived fuels for compression-ignition engines and other applications. Compression-ignition engines play major roles in transport, where they are used for buses, trucks, and trains, and in some regions (such as Europe) for cars as well. Such engines are especially important for developing and transition economies, where in 1996 diesel fuel accounted for half of all transport fuel (relative to a fifth in the United States; EIA, 1999a). The efficiency benefits offered by these engines will be even more important in the future as transport demand grows. For example, the World Energy Council's 1995 market rules scenario projects that the number of cars will grow by six times between 1990 and 2020 in developing and transition economies, from 95 million to 580 million (WEC, 1995). Both improved engines and improved fuels will be needed to help mitigate the challenges that such growth poses for energy supply security, air quality, and greenhouse gases.

CIDI engines are promising advanced technologies for improving efficiency, especially when used in hybrid vehicles. Concerns about CIDI hybrids include high costs and whether they will be able to meet expected tougher regulatory goals for NO_x and particulate emissions. In its fourth review of the PNGV, the U.S. National Research Council urged the PNGV to consider shifting emphasis in its CIDI research to non-hybrid versions, in light of the high costs of hybrids (NRC, 1998).

Among the leading candidate fuels for addressing the challenges posed by compression-ignition engines are synthetic middle distillates (SMDs) and dimethyl ether (DME). SMDs are straight-chain hydro-

The fossil energy system can evolve in ways consistent with sustainable development objectives if public policies guide a high rate of innovation toward super-clean fossil energy technologies

carbon fuels (paraffins and olefins) produced through the Fischer-Tropsch (F-T) process. The F-T process begins with the production of syngas from a carbonaceous feedstock—for example, from natural gas through steam reforming or partial oxidation, or from coal through O₂-blown gasification and even from biomass through gasification.

SMDs are well suited for use in compression-ignition engines, in part because of their high cetane numbers.³⁵ Moreover, they contain no benzene, other aromatic compounds, or sulphur. Measurements have shown 13–37 percent reductions in particulate emissions and 6–28 percent reductions in NO_x emissions relative to operation on diesel fuel (Sirman, Owens, and Whitney, 1998; Schaberg and others, 1997; Norton and others, 1998). Even greater reductions would be likely if the engines were optimised for use with these fuels, including exhaust gas aftertreatment as well as engine modifications.

The well-established F-T technology for making SMDs can be used with either natural gas or coal as feedstock. Near-term activities will be focussed on use of low-cost supplies of natural gas. Despite high production costs, Shell's small, natural-gas-based Malaysian SMD plant (12,500 barrels a day; see below) made money by selling SMDs for making blends with ordinary diesel fuel to enable compression-ignition engines to meet the tough air pollution standards in California and by selling high-value coproducts (for example, waxes) in niche markets.³⁶

Efforts to reduce costs will involve building larger plants. For example, Exxon is considering building a large (50,000–100,000 barrels a day) SMD plant in Qatar as a strategy for developing that country's vast low-cost gas supplies (Fritsch, 1996; Corzine, 1997). Reducing costs will also involve pursuing polygeneration strategies (see the next section).

Another candidate fuel for compression ignition engines is DME, an oxygenated fuel that can be produced from any carbonaceous feedstock by a process that begins, as in the case of MeOH and SMDs, with syngas production. Today DME is produced (150,000 tonnes a year) mainly to provide a replacement for chlorofluorocarbons as a propellant in aerosol spray cans. Not only does DME not harm the ozone layer (it degrades quickly in the troposphere), but it is non-toxic and non-carcinogenic.

For compression ignition engine applications, DME offers a high cetane number and the potential to achieve low emissions without tailpipe emission controls. Because DME has no carbon-carbon bonds, soot emissions from its combustion are zero. In addition, NO_x emissions can be substantially less than with ordinary diesel fuel. Truck engine emission tests show that NO_x emissions are down 55–60 percent and particle emissions are down 75 percent relative to diesel fuel. Residual particle emissions appear to come from the lubricating oil (Fleisch and Meurer, 1995).

DME has also been identified as an especially promising clean cooking fuel (Chen and Niu, 1995). Its wide availability in developing countries could dramatically mitigate the horrendous air pollution

health impacts from burning biomass and coal for cooking (chapters 3 and 10). The main drawback of DME is that at atmospheric pressure it boils at –25 degrees Celsius, so it must be stored in moderately pressurised (9-bar) tanks (much as liquid petroleum gas, which boils at –42 degrees Celsius, is stored). Thus infrastructure challenges would be more demanding in shifting to DME than in shifting to SMDs. But this is not a show-stopper.

Today DME is produced by catalytic dehydration of MeOH and is thus more costly than MeOH. However, an advanced single-step process under development by Haldor Topsoe would make it possible to make DME from natural gas at higher efficiency and less cost than for MeOH. Haldor Topsoe and Amoco have estimated that if DME were produced in large plants in areas with low-cost natural gas, it could be produced at costs not much higher than comparable diesel prices, taking into account the environmental benefits of DME (Hansen and others, 1995). Also promising is the outlook for DME production in polygeneration systems (see below).

It is very likely that fuel strategies will have to be complemented by engine strategies to realise needed low levels of emissions from compression-ignition engines. The possibilities include the use of high-pressure fuel injectors, of catalytic converters to reduce the soluble organic fraction of the particulates, and of particulate traps positioned in the engine exhaust stream—along with some means of burning off the collected particulate matter, most of which is soot (Walsh, 1995; 1997). One new twist is that new engines and exhaust controls being developed to dramatically reduce the mass concentration of particles, in response to tightening air quality regulations, seem to give rise to larger number concentrations (Kittelson, 1998; Bagley and others, 1996; Kruger and others, 1997; Mayer and others, 1995).³⁷ The larger number concentrations might be problematic because of growing concerns about health impacts of small particle pollutants—although the public health implications of this emissions shift are unclear because of the paucity of data.

Although there are many promising technological opportunities to reduce emissions from compression-ignition engines, it is not clear if advanced fuel and engine technological strategies will be adequate to address air quality challenges fully. The fuel cell is a competing technology for addressing these challenges (see below).

Polygeneration strategies for synthetic fuels production. Just as cogeneration can lead to improved economics relative to production of electricity and process steam in separate facilities (see tables 8.5 and 8.7), so can synthetic fuel production economics be improved by polygeneration—including as coproducts various combinations of electricity, steam, town gas, and chemicals. Especially promising are strategies that coproduce electricity and synthetic fuels from syngas in once-through processes—in which syngas is passed once through a reactor to produce synthetic fuel, and the unconverted syngas is burned to produce electricity in a combined cycle.

Once-through processes are well matched to new liquid-phase

TABLE 8.11. TRIGENERATION VERSUS SEPARATE PRODUCTION OF METHANOL AND COGENERATION USING COAL GASIFICATION TECHNOLOGY

Rates of activity and costs	Separate production facilities for MeOH and cogeneration			Trigeneration plant
	MeOH plant	Cogeneration plant	Total	
Power generation rate (megawatts-electric)	—	400	400	400
Process steam production rate, 10-15 bar (megawatts-thermal)	—	400	400	400
Methanol production rate (megawatts-thermal)	400	—	400	400
Coal input rate (terajoules per hour)	2.46	3.88	6.34	6.46
First Law efficiency (percent)	58.6	74.3	68.1	66.9
CO ₂ emission rate (tonnes per hour)	211	333	544	555
Capital investment (millions of dollars)	379	537	916	700
Annual energy production cost (millions of dollars per year)				
Capital	43.66	61.86	105.52	80.64
Operation and maintenance (4 percent of capital cost per year)	15.16	21.48	36.64	28.00
Fuel	17.25	27.21	44.46	45.30
Total annual energy cost	76.07	110.55	186.62	153.94
Specific cost of energy (dollars per thousand kilowatt-hours)	For MeOH:	For power:		For MeOH:
Gross cost	27.1	39.4	—	54.9
Credit for steam coproduct	—	-15.0	—	-15.0
Credit for electricity coproduct	—	—	—	-24.4
Net cost	27.1 (\$0.12 per litre)	24.4	—	15.5 (\$0.07 per litre)

Note: Based on calculations by Robert Moore (formerly Air Products), building on Dale Simbeck's analysis in table 8.7 for a gasification-based cogeneration plant, assuming Air Products' liquid-phase reactor for MeOH production. Engineering plus contingencies and general facilities are each 10 percent of process capital equipment costs. The annual capital charge rate is 11.5 percent. The coal price is \$1 per gigajoule (see note c, table 8.4). The annual average capacity factor is 80 percent.

TABLE 8.12. QUADGENERATION VERSUS SEPARATE PRODUCTION OF TOWN GAS AND TRIGENERATION USING COAL GASIFICATION TECHNOLOGY

Rates of activity and costs	Separate production facilities for town gas and trigeneration			Quadgeneration plant
	Town gas plant	Trigen plant	Total	
Power generation rate (megawatts-electric)	—	400	400	400
Process steam production rate, 10-15 bar (megawatts-thermal)	—	400	400	400
Methanol production rate (megawatts-thermal)	—	400	400	400
Syngas production rate (megawatts-thermal)	400	—	400	400
Coal input rate (terajoules per hour)	1.89	6.46	8.35	8.36
First Law efficiency (percent)	76.0	66.9	69.0	68.9
CO ₂ emission rate (tonnes per hour)	163	555	718	718
Capital investment (millions of dollars)	228	700	928	783
Annual energy production cost (millions of dollars per year)				
Capital	26.27	80.64	106.91	90.20
Operation and maintenance (4 percent of capital cost per year)	9.12	28.00	37.12	31.32
Fuel	13.25	45.30	58.55	58.63
Total annual energy cost	48.64	153.94	202.58	180.15
Specific cost of energy (dollars per thousand kilowatt-hours)	For town gas:	For MeOH:		For town gas:
Gross cost	17.3	54.9	—	64.2
Credit for steam coproduct	—	-15.0	—	-15.0
Credit for electricity coproduct	—	-24.4	—	-24.4
Credit for MeOH coproduct	—	—	—	-15.5
Net cost	17.3 (\$4.80 per gigajoule)	15.5 (\$0.07 per litre)	—	9.3 (\$2.60 per gigajoule)

Note: Based on calculations by Robert Moore (formerly Air Products), building on Dale Simbeck's analysis in table 8.7 for a gasification-based cogeneration plant, assuming Air Products' liquid-phase reactor for MeOH production. Engineering plus contingencies and general facilities are each 10 percent of process capital equipment costs. The annual capital charge rate is 11.5 percent. The coal price is \$1 per gigajoule (see note c, table 8.4). The annual average capacity factor is 80 percent.

reactors. With conventional gas-phase reactors, relatively low conversions are achieved in a single syngas pass through the reactor, so that syngas is usually recycled to achieve higher conversions using recycling equipment that is typically capital- and energy-intensive. New liquid-phase reactors—which involve bubbling syngas through a column of heavy oil in which catalysts appropriate to the desired conversion are suspended—offer outstanding heat removal capability in controlling highly exothermic reactions and can achieve high conversions in a single pass, making recycling less attractive and once-through conversion more attractive.

To illustrate polygeneration based on coal-derived syngas, table 8.11 presents calculations for the coproduction of 400 megawatts each of MeOH, electricity, and process steam (trigeneration) from coal by adding extra syngas production capacity to the system described in table 8.7 for the cogeneration of 400 megawatts each of electricity and process steam. Table 8.12 presents calculations for the coproduction of 400 megawatts each of town gas, MeOH, electricity, and process steam (quadgeneration) from coal by adding still more syngas production capacity to the system described in table 8.11.³⁸ Costs for MeOH produced in liquid-phase reactors through once-through processes have been extensively analysed (Drown and others, 1997), and the technology is relatively well developed.³⁹

Consider first the trigeneration system (see table 8.11). In contrast to the cogeneration system (see table 8.7) from which it is evolved, trigeneration does not lead to further fuel savings, but capital cost savings are large. Values assumed for coproducts are \$0.0150 a kilowatt-hour for steam (its cost in a stand-alone boiler) and \$0.0244 a kilowatt-hour for electricity (its cost in gasification-based cogeneration). Thus the incremental cost for methanol is \$0.07 a litre (\$4.30 a gigajoule)—compared with \$0.012 a litre for MeOH produced from coal in a stand-alone plant. This MeOH cost is less than the average U.S. refinery (wholesale, untaxed) gasoline price in 1997 (\$5.10 a gigajoule).

In the quadgeneration example, extra syngas is produced as town gas for distribution by pipelines to nearby users—for example, small-scale cogeneration facilities based on compression-ignition reciprocating engines with pilot oil (see above). Note that, whereas producing 400 megawatts of town gas in a dedicated gasification facility would cost \$4.80 a gigajoule, the cost of adding an extra 400 megawatts of syngas capacity for town gas purposes at a trigeneration plant would cost instead \$2.60 a gigajoule, because of the scale economy effect. For comparison, the average 1997 U.S. city-gate price of natural gas was \$3.30 a gigajoule.

The trigeneration and quadgeneration calculations illustrate the importance of building large, centralised, coal-syngas-based production systems to serve distributed markets for the products. The synthetic liquid fuels produced can be readily transported to vast markets of remote users. Likewise, the electricity coproduct can serve large markets if the polygenerator is able to sell the electricity coproduct into the electric grid at market rates. In contrast, the extra syngas produced as town gas can be transported economically

only up to distances of 10–30 kilometres from the production facility. But even in this case, the markets served could be large if the centralised coal conversion plant were located near cities where large numbers of small factories, commercial buildings, and apartment buildings could be served.

Urban siting for these facilities can be considered for gasification-based coal conversion systems because of the very low levels of air pollutant emissions that can be realised (see table 8.1). The major restriction imposed by the market for the strategy illustrated in tables 8.7, 8.11, and 8.12 is that the process steam demand is defined by the needs of the host and is thus very site-specific, with limited overall market opportunity. Thus the coproduction of process steam should be considered an important initial market for helping to launch coal gasification technology in the market rather than a large, unconstrained market opportunity. Polygeneration strategies will often make economic sense, even without the benefit of the process steam coproduct.

Coal-based polygeneration strategies will be especially important for coal-rich, natural-gas-poor countries like China. Although most polygeneration activity relating to syngas production is taking place in industrialised countries, it is also getting under way in some developing countries (table 8.13—and table 8.6 above). Consider that—although China has deployed no modern O₂-blown gasifiers in the power sector—it is already using many such gasifiers in the chemical process industries.⁴⁰ Such industries might provide better homes for launching IGCC technologies on the market in China and many other countries than would the electric power industry as it now exists.

Simbeck and Johnson (1999) point out that gasification-based polygeneration is being carried out in some countries without subsidy at refineries and chemical plants, because the economics are inherently attractive. They also point out that polygeneration based on gasification of refinery residues will often be more attractive economically than for coal. Such residues often have high sulphur content and are priced low. Moreover, capital costs tend to be lower—for example, because solids handling, crushing, and feeding systems are not needed. In addition, the generally lower levels of ash in heavy oils means less fouling of syngas coolers, so that lower cost designs might be employed (Todd and Stoll, 1997). Yet much of the technology is the same as for coal, so that this early experience will be helpful in buying down the cost of the technology as experience accumulates, making the technology increasingly attractive for coal as well.

In contrast to the use of large-scale polygeneration systems for improving the economics of coal-based synthetic fuels, the focus for natural-gas-based polygeneration is likely to be on making synfuels production more attractive at small scales—by enabling the production of easy-to-transport liquid fuels from remote, small-scale sources of cheap natural gas.

To illustrate, consider the economics of the coproduction of F-T liquids and electricity from natural gas using liquid-phase reactors in a once-through process. Choi and others (1997) found that such systems producing about 8,800 barrels a day of liquids—plus 84

TABLE 8.13. LARGE COMMERCIAL GASIFICATION-BASED PROJECTS THAT DO NOT GENERATE ELECTRICITY

Location	Plant owner	Technology	Syngas out (megawatts-thermal)	Feedstock(s)	Product(s)	Start-up year
South Africa	Sasol-II	Lurgi Dry Ash	4,130	Sub-bituminous coal	F-T liquids	1977
South Africa	Sasol-III	Lurgi Dry Ash	4,130	Sub-bituminous coal	F-T liquids	1982
United States	Dakota Gasification Company	Lurgi Dry Ash	1,545	Lignite, refinery residues	Synthetic natural gas	1984
Malaysia	Shell MDS Sdn. Bhd.	Shell	1,032	Natural gas	Middle distillates	1993
Germany	Linde AG	Shell	984	Visbreaker residues	Methanol, H ₂	1997
South Africa	SASOL-I	Lurgi Dry Ash	911	Sub-bituminous coal	F-T liquids	1955
United States	Unspecified	Texaco	656	Natural gas	MeOH, CO	1979
Taiwan, China	Chinese Petroleum Corp.	Texaco	621	Bitumen	H ₂ , CO	1984
Germany	Hydro Agri Brunsbüttel	Shell	615	Heavy vacuum residues	NH ₃	1978
Germany	VEBA Chemie AG.	Shell	588	Vacuum residues	NH ₃ , MeOH	1973
Czech Republic	Chemopetrol a.s.	Shell	492	Vacuum residues	NH ₃ , MeOH	1971
Brazil	Ultrafertil S.A.	Shell	451	Asphalt residues	NH ₃	1979
China	Shanghai Pacific Chemical Corp.	Texaco	439	Anthracite coal	MeOH, town gas	1995
China	Shanghai Pacific Chemical Corp.	IGT U-Gas	410	Bituminous coal	Fuel gas, town gas	1994
India	Gujarat National Fertilizer Corp.	Texaco	405	Refinery residues	NH ₃ , MeOH	1982
Portugal	Quimigal Adubos	Shell	328	Vacuum residues	NH ₃	1984

Source: Simbeck and Johnson, 1999.

megawatts-electric of by-product power from remote gas—would be able to provide liquid fuels at a cost competitive with liquid fuels derived from \$19 a barrel crude oil, assuming that the by-product electricity is sold for \$0.03 a kilowatt-hour. The authors also found that such a plant would be competitive with a F-T plant employing recycling technology producing five times as much synfuels output. Thus, as long as crude oil prices do not plunge much below \$20 a barrel, gas liquids derived from natural gas through liquid-phase reactor technology in once-through configurations are likely to be cost-competitive.

The benefits of this technology are related not just to the product price but also to natural gas resource development prospects. The total plant cost (including the cost of an 84-megawatt-electric combined cycle power plant) estimated by Choi and others (1997) is \$415 million. This is in contrast to capital requirement per plant of \$2–4 billion for a typical liquid natural gas (LNG) facility. Thus the investment hurdle is far less for a once-through F-T liquids plus power plant than for an LNG plant. Moreover, the proven gas reserves required per site for an F-T plant amounts to only 1 exajoule, relative to 6–8 exajoules for an LNG facility.

Thus F-T technology makes it feasible to exploit much smaller

remote gas fields than is feasible for LNG. Of course, this strategy requires that there be markets for the electricity coproduct, and many remote gas fields are not near transmission networks. However, the costs of building transmission lines to deliver baseload electricity to demand centres might often be economically attractive (requiring much less investment than for energy-equivalent gas infrastructure) given the low generation cost, particularly if outputs of several small fields in the region could be combined for long-distance transmission at scales on the order of 1 gigawatt-electric.

Air Products is also developing liquid-phase reactor technology for DME production (Peng and others, 1997; Peng and others, 1998). As in the case of MeOH and F-T liquids production, liquid-phase reactor technology used in conjunction with once-through process is expected to make DME production from natural gas economically attractive at relatively small scales.

There needs to be continuing research and development on all these liquid-phase reactor synthetic fuels technologies—especially on DME, which has attractive attributes but is the least developed of the technologies described here. But the main barriers to the deployment of these technologies are institutional rather than technological: Their economic viability depends on the ability of the polygenerator

to sell the electricity coproduct into the electricity grid at a fair market price. Reforms to promote more competition in power markets will be helpful in nurturing the development of syngas-based synthetic fuels technology.

Hydrogen and the quest for near-zero emissions. The strategic importance of having an energy system for the long term in which H₂ is a major clean energy carrier has been noted (see box 8.1). No CO₂ or air pollutants are emitted during use when H₂ is consumed in fuel cells. If H₂ is burned in gas-turbine-based power plants, the only air pollutant is NO_x (formed by oxidation of N₂ in air); but these NO_x emissions can be controlled to very low levels by lean combustion strategies or by injecting steam or water into the combustor or compressor air stream of suitably designed power plants.⁴¹

When H₂ is made electrolytically by decomposing water from renewable or nuclear electric sources, CO₂ and pollutant emissions associated with H₂ manufacture and thus life-cycle CO₂ emissions are also zero or near zero. When H₂ is made from a fossil fuel, life-cycle pollutant emissions are also very low,⁴² although CO₂ emissions from H₂ manufacture can be high. However, for large, centralised H₂ production facilities, CO₂ can be generated as a nearly pure by-product that can be disposed of (for example, in a geological reservoir) at modest cost. Even if this CO₂ had to be disposed of in aquifers (where there is no credit for enhanced resource recovery) that are as far away as 500 kilometres from production sites, the cost of disposal based on current technology would be less than \$50 a tonne of carbon (Williams, 1999b). If the H₂ so produced were a competitive energy carrier (which is not the case today), the cost of CO₂ emissions avoided would approach this disposal cost—which is less than the least avoided cost for the coal electric generation technologies described in table 8.9.

Concerns are often raised about H₂ safety. In this regard, H₂ is better than other fuels in some ways, worse in other ways, and in still other ways just different (Ringland, 1994). However, H₂ can be used safely if procedures are followed that respect its physical and chemical properties (box 8.3). Such theoretical considerations are buttressed by extensive experience with residential town gas (typically 50 percent H₂), which was widely used in the United States until the 1940s and in Europe until the 1960s, and is still used in China and South Africa.

The manufacture of H₂ from a fossil fuel begins with syngas production—the mostly costly step in the overall process. Thus, if the world pursues the syngas-based energy technologies described in previous sections, it would be embarked on a path that would facilitate a transition to H₂.

The dominant commercial H₂ production technology is reforming of natural gas. H₂ can also be made through gasification of any carbonaceous feedstock (Williams and others, 1995), including coal, heavy oils, biomass, or municipal solid waste (Larson, Worrell, and Chen, 1996), or through electrolysis of water using renewables (for example, hydropower, wind, or solar; Ogden and Williams, 1989), nuclear energy, or other power sources. Until fossil fuel prices are far higher than at present, electrolytic approaches for

producing H₂, now and in the future, will tend to be much more costly than making H₂ from natural gas, coal, or other fossil fuels—even when the added costs of CO₂ sequestration are taken into account (Williams, 1998; IPCC, 1996a).⁴³

Technology for producing H₂ from fossil fuels is well established commercially. Although H₂ is currently used only in niche applications as an energy carrier (for example, for the U.S. National Aeronautics and Space Administration's space shuttle launches), it is widely used in oil refining and the chemical process industries. H₂ is produced commercially in the United States at a rate of 8.5 million tonnes a year (Moore and Raman, 1998) or 1.2 exajoules a year (1.25 percent of U.S. energy consumption). Several large-scale polygeneration plants have been or are being built around the world for the coproduction of H₂ and electricity from petroleum residues through gasification (see table 8.6).

Such projects reflect the rapid growth (10 percent a year) in demand for H₂ at refineries, as a result of cleaner transportation fuel mandates and requirements for processing heavier crudes. The major obstacle to widespread deployment of H₂ as an energy carrier is the fact that H₂ is not competitive in energy markets. There are two ways this situation might change: the emergence of H₂-using technologies that put a high market value on H₂, and H₂ production technologies that reduce its cost—the prospects for which are reviewed in the next two sub-sections.

Enhancing the prospects for H₂ with fuel cell vehicle technology. Successful commercialisation of fuel cell vehicles would give H₂ a high market price, because H₂ fuel cell vehicles would typically be much more fuel efficient than internal combustion engine vehicles with the same performance and would offer substantial air quality benefits.⁴⁴ Although H₂ storage onboard vehicles is challenging,

BOX 8.3. HYDROGEN SAFETY

Hydrogen is widely perceived to be an unsafe fuel, because it burns or detonates over a wider range of mixture with air than other fuels, and very little energy is required to ignite H₂ mixed with the minimum amount of air needed to completely burn it. Although H₂ is flammable in air over a wide range of mixtures, when used in unconfined spaces (as will be typical in transport applications), the lower limits for flammability and detonability matter most. In this regard, H₂ is comparable to or better than gasoline. Gasoline and natural gas can also be easily ignited with low-energy ignition sources such as electrostatic discharges—like those that result from a person walking across a rug. Moreover, in dilute mixtures with air, the ignition energy for H₂ is essentially the same as for methane. In another regard, H₂ has an advantage over gasoline: In case of a leak in an unconfined space, H₂ will disperse quickly in the air because of its buoyancy, whereas gasoline will puddle.

An important safety issue for H₂ is leaks—prevention, detection, and management, particularly in confined spaces. Areas where H₂ is stored and dispensed have to be well ventilated; because of H₂'s buoyancy, this means providing vents at the highest points in ceilings. Considering all these issues, a major study of H₂ safety (Ringland, 1994) concluded that "H₂ can be handled safely, if its unique properties—sometimes better, sometimes worse, and sometimes just different from other fuels—are respected."

BOX 8.4. HYDROGEN STORAGE FOR MOTOR VEHICLES

Storing H₂ onboard motor vehicles is challenging because of H₂'s low volumetric energy density. With current technology, the least costly option is compressed gas (typically at 350 atmospheres; James and others, 1996), for which the storage density is less than one-tenth gasoline's.

Volumetric storage densities do not have to equal that of gasoline to make H₂ storage manageable—in part because of the high fuel economies of fuel cell vehicles. An H₂ fuel cell car that meets the PNGV fuel economy goal (2.94 litres per 100 kilometres or 80 miles a gallon, gasoline-equivalent) would require 240 litres of compressed H₂ storage capacity for a 680-kilometre (425-mile) range between refuellings, compared to 64 litres for a typical gasoline ICE car (9.4 litres per 100 kilometres, or 25 miles a gallon fuel economy). A prototype H₂ fuel cell van introduced in 1997 by Daimler Benz involved storing H₂ cylinders in an under-the-roof compartment; a car with a PNGV fuel economy and a 680-kilometre range might use three such cylinders, each 110 centimetres long and 32 centimetres in diameter.

In comparison with gaseous storage, storage volumes could be reduced by half with metal hydrides, but storage system weight would increase several times, and costs would be much higher. H₂ liquefaction could reduce storage volumes to a third of those for compressed H₂ but would require consuming electricity equivalent to a third of the H₂ (higher heating value basis), and boil-off (typically 1.5–2 percent a day) makes this option wasteful for private cars that are typically used an hour a day or less.

H₂ storage using carbon nanofibres is under development through alternative approaches (Chambers and others, 1998; Chen and others, 1999; Liu and others, 1999; Dresselhaus, Williams, and Ecklund, 1999). It offers the potential for dramatically improving performance—some options are even able to store H₂ at relatively high energy densities near atmospheric pressure and ambient temperatures. Successful development of one or more of these technologies might make storing H₂ in fuel cell vehicles no more difficult than storing gasoline in gasoline internal combustion engine cars.

problems seem to be surmountable with existing technologies, and some promising advanced options could plausibly make H₂ storage no more challenging for fuel cell vehicles than gasoline storage is today for internal combustion engine vehicles (box 8.4).

A fierce global competition is under way to accelerate the development of fuel cell vehicles (Steinbugler and Williams, 1998; Appleby, 1999). Nearly all major auto manufacturers have produced test vehicles (table 8.14). Several automakers have set goals to introduce fuel cells into the automotive market during 2003–10. Developmental efforts are focused on PEM fuel cells. Industrial interest is motivated largely by the prospect that fuel cell vehicles will have zero or near-zero emissions, without tailpipe emission controls. The air quality benefits provide a powerful rationale for developing fuel cells for a wide range of vehicles, including buses, trucks, locomotives, and small two- and three-wheeled vehicles (which account for much of the air pollution in cities of the developing world; PCAST Panel on ICERD³, 1999), as well as cars—the focus of fuel cell vehicle development in industrialised countries.

Under a zero-emission-vehicle (ZEV) technology-forcing policy to meet its air quality goals, the state of California has mandated that 10 percent of new cars sold in the state be ZEVs by 2003. Initially,

the battery-powered electric vehicle (BPEV) was the focus of efforts to meet the mandate. Although there have been some significant advances (for example, in electric drive-train technology), the BPEV is no longer the only focus of ZEV developmental efforts; the technological challenges of overcoming the problems of long battery recharging times, modest vehicle ranges between rechargings, and high costs have proven formidable. The ZEV mandate has also been catalytic in stimulating industrial interest in fuel cell vehicles as an alternative technology that offers good prospects for addressing the shortcomings of the BPEV.

Although the natural fuel for fuel cell vehicles is H₂, many efforts aimed at commercialising fuel cell vehicles are emphasising H₂ production onboard the car from either MeOH or gasoline, because an H₂ refuelling infrastructure is not yet in place. MeOH and gasoline are liquid fuels that are easily stored and transported. Processing MeOH onboard cars is easier and has been successfully demonstrated. Processing gasoline is more difficult, requiring higher temperatures, but gasoline offers the clear advantage that no new fuel infrastructure is needed. Detailed modelling has shown that MeOH and gasoline fuel cell vehicles would be a third less fuel efficient than H₂ fuel cell vehicles but still more fuel efficient than gasoline-fuelled internal combustion engine vehicles (Ogden, Kreutz, and Steinbugler, 1998).

Although fuel cell vehicles might be launched on the market using MeOH or gasoline, an H₂ fuel cell vehicle would be less costly to own and operate—largely because of expected lower capital and maintenance requirements. Even if fuel cell vehicles are launched with gasoline or MeOH, an internal market pressure subsequently would develop that would encourage a shift to H₂ as soon as an H₂ infrastructure could be put in place (Steinbugler and Williams, 1998; Ogden, Kreutz, and Steinbugler, 1998). By the time fuel cell vehicles account for a large enough fraction of the market to justify the infrastructure investments, a plausible scenario for supplying the needed H₂ would be to establish near each major city one or more large facilities for making H₂ from some mix of natural gas, refinery residues, coal, municipal solid waste, and biomass. These facilities should be large enough to justify economically sequestration of the separated CO₂ but sufficiently close to vehicle refuelling stations that only relatively modest-scale H₂ pipeline networks would be needed to distribute the H₂ to users (Williams, 1999b).

With such an infrastructure in place, fuel cell vehicles could then offer transportation services with zero or near-zero emissions of CO₂ (as well as air pollutants). The added cost to consumers for sequestering the separated CO₂ would amount to less than \$0.002 per kilometre of driving (less than 1 percent of the cost of owning and operating a car), assuming current H₂ production technology for coal and natural gas (Kaarstad and Audus, 1997) and fuel cell vehicles having the target gasoline-equivalent fuel economy for the U.S. PNGV (80 mpg, or 2.94 litres per 100 kilometres).

The potential for reducing CO₂ emissions with H₂ fuel cell vehicles depends on how fast the technology penetrates the market. Even the most optimistic scenarios project capturing a fourth of the new car market by 2025—which implies displacing only a tenth of all cars

by that time. If all fuel cell cars were fuelled with H₂, and the separated CO₂ were sequestered, global CO₂ emissions would be only 0.1 GtC less than under business-as-usual conditions. Such considerations illustrate the long periods required for new technologies to have major impacts—and underscore the importance of launching accelerated development initiatives for technologies that offer major public benefits, so that they can have significant impacts 25 years in the future.

Can fuel cell vehicles compete? The leading North American developer of PEM fuel cell fuels has said in press releases that PEM fuel cells will be competitive in transport applications when production volumes reach 250,000–300,000 fuel cell vehicle engines a year, which the company expects well before 2010. Some studies in the public domain also project that mass-produced fuel cell vehicles can be competitive (Thomas and others, 1998a, b). Although the economics of fuel cell vehicle technology are still very uncertain, no intrinsic costs of PEM fuel cell materials or fabrication are so obviously high as to preclude mass-produced fuel cell vehicles from being competitive. The fuel cell's inherent simplicity (for example, no moving parts) and mild operating conditions (80 degrees Celsius) relative to internal combustion engine vehicles also suggest substantial cost reduction opportunities.

It will not be easy for the fuel cell vehicle to displace the internal combustion engine vehicle, an entrenched, mature technology. Moreover, as noted, internal combustion engine technology is still being improved. Japanese automakers have already introduced clean spark-ignited internal combustion–electric hybrids that offer twice the fuel economy of conventional internal combustion engine vehicles. It will be difficult for gasoline fuel cell vehicles to compete with these hybrids, because the two sets of vehicles will have comparable efficiencies, and it is always difficult for a new technology to displace an old one—unless it offers enormous advantages.

The air pollution issue will be centre stage during the competition between fuel cell and hybrid internal combustion engine vehicles to be car of the future. Meeting air quality goals will be especially challenging for hybrids involving compression-ignition engines (NRG, 1998). Moreover, Ross and others (1995) estimate that there will be a growing gap between actual life-cycle emissions and regulated emissions for internal combustion engine vehicles with spark-ignited engines (see table 8.3).

Hybrids fueled with H₂ would pose significant competition for H₂ fuel cell vehicles in the race to zero emissions. NO_x would be the only significant pollutant emission for H₂ hybrids; because ultra-

TABLE 8.14. FUEL CELL TEST VEHICLES AROUND THE WORLD

Year	Company	Fuel storage	Fuel cell power system			Range (kilometres)
			Power output (kilowatts)	Auxiliary power	Vehicle type	
1993	Ballard	Pressurised H ₂	120	No	Bus	160
1994	DaimlerChrysler	Pressurised H ₂	54 net	No	Necar I (van)	130
1996	DaimlerChrysler	Pressurised H ₂	50 net	No	Necar II (van)	250
1996	Toyota	Metal hydride	20	Pb battery	Car	250
1997	Ballard	Pressurised H ₂	205 net	No	Bus	400
1997	DaimlerChrysler	MeOH (onboard reformer)	50	No	Necar III (car)	Greater than 400
1997	Mazda	Metal hydride	20	Ultra-capacitor	Car	170
1997	DaimlerChrysler	Pressurised H ₂	190 net	No	Nebus (bus)	250
1998	Renault	Liquid H ₂	30	Ni-MH battery	Station wagon	400
1998	Opel	MeOH (onboard reformer)	50 (motor)	Ni-MH battery	Minivan	-
1999	DaimlerChrysler	Liquid H ₂	70	No	Necar IV (car)	400
1999	Ford	Pressurised H ₂	75	No	Car	96
1999	Nissan	MeOH (onboard reformer)	10	Li-ion battery	Station wagon	—
1999	Honda	Metal hydride	60	Ni-MH battery	Car	—
1999	Honda	MeOH (onboard reformer)	60	Ni-MH battery	Station wagon	—
2000	General Motors	Chemical hydride	75	Ni-MH battery	Car	800

Source: Various fuel cell vehicle newsletters.

lean combustion is feasible with H₂ fueling, NO_x emissions of hybrids can be controlled to low levels. However, such hybrids would be less fuel efficient than H₂ fuel cell vehicles and thus more costly to operate. The economic winner of this race to zero emissions depends on what relative vehicle costs turn out to be when vehicles are mass produced.

Despite the many uncertainties, there is growing private sector confidence in the prospects for making fuel cell vehicle technology competitive, as indicated by substantial auto industry investment levels and growing attention being paid to the technology also by the oil industry (API, 1999).⁴⁵ Making fuel cell vehicles competitive in the near term requires accelerated commercialisation, because current costs are high, and large production volumes are needed to bring costs down quickly. (Fuel cells—like many other new technologies—are expected to be well described by learning curves for which costs decline 10–30 percent for each cumulative doubling of production; Rogner, 1998; Lipman and Sperling, 1999.) Recognising this, one industrial consortium for fuel cell vehicle development—automakers DaimlerChrysler, Ford, and Mazda, and fuel cell developer Ballard Power Systems—has bullishly set an ambitious goal of selling 40,000 fuel cell cars a year by 2004.

Enhancing prospects for hydrogen with advanced hydrogen production technologies. H₂ might eventually be able to compete in fuel cell vehicle markets using current H₂ production technologies. But new H₂ production technologies are needed to enable H₂ to compete in applications such as stationary power generation, for which H₂ fuels cells do not offer major efficiency advantages over conventional fossil energy technologies. There are many opportunities.

One set of opportunities involves integrating CO₂ removal into production processes in creative ways—for example, coproduction of H₂ and F-T liquids from natural gas to reduce costs by avoiding the need for a costly air separation plant.⁴⁶ Advanced gas separation technologies warrant focussed attention, especially for separating CO₂ and H₂.⁴⁷ One innovative technology receiving development support from the U.S. Department of Energy involves cooling the pressurised gaseous mixture (mainly CO₂ and H₂) exiting the water-gas shift reactors to less than 10 degrees Celsius, then bubbling the gases through a water column. Under appropriate conditions the H₂ passes through but the CO₂ is converted into a CO₂ clathrate hydrate that is heavier than water and easily removed. With this technology it might be possible to substantially reduce the energy and capital costs of CO₂ removal and disposal (Spenser, 1999; Spencer and Tam, 1999).

Another promising set of options involves using inorganic membrane reactors to simultaneously drive the water-gas shift reaction towards maximum H₂ yield and separate the H₂ and CO₂. Williams (1999b) points out that using such reactors offers the potential for making H₂ from coal (without CO₂ sequestration) at costs that approach typical natural gas prices for electricity producers in the United States, with CO₂ sequestration costs adding \$1.00–1.50 a gigajoule. At such costs, coal-derived H₂ with sequestration of the separated CO₂ could be an economically attractive option even for central-station

power generation in a greenhouse gas emissions-constrained world.

In one variant of this concept, the Parsons Group has proposed a plant design to make H₂ from coal that involves separating H₂ from CO₂ at high temperatures using porous ceramic membranes. Substantial cost reductions are projected relative to conventional methods for making H₂ from coal (Parsons Infrastructure and Technology Group, 1998; Badin and others, 1999). But Williams (1999b) suggests that attention be given instead to carrying out the gas separations at much lower temperatures than proposed by the Parsons Group, to avoid the formidable technological difficulties of high-temperature processes. Operation of membrane reactors at lower temperatures increases the number of technological options for gas separation, including especially promising non-porous composite metal membrane technologies that can provide H₂ of high purity—important for applications involving PEM fuel cells, which are poisoned by CO at low (10 parts per million by volume) concentrations.

If methane hydrates could be exploited at large scales (chapter 5), ways would eventually be needed to extract the energy without releasing the separated CO₂ into the atmosphere, to prevent a greenhouse disaster.⁴⁸ One way this might be accomplished is to make H₂ from the methane using steam reforming and leave behind in nearby reservoirs the by-product CO₂ as CO₂ clathrate hydrates (PCAST Energy Research and Development Panel, 1997), which are stable under pressure and temperature conditions similar to those for methane hydrates. Indeed, sub-seabed disposal of CO₂ in the form of clathrate hydrates has been proposed as a major option for effectively disposing of CO₂ generated in fossil energy systems (Koide and others, 1997).

Alternatively, H₂ could be extracted through methane thermal decomposition to produce H₂ and carbon black (Steinberg and Cheng, 1989), an endothermic process. If some of the produced H₂ is burned to provide the needed heat, the process would be CO₂-emissions free, and the net H₂ energy yield would still be more than 50 percent of the energy content of the original methane. Although this conversion would have much less than the 80–85 percent efficiency that can be achieved with conventional reforming technologies, methane thermal decomposition might prove interesting if there are unforeseen obstacles (political or technical) to large-scale CO₂ sequestration (carbon black is easier to store than CO₂).

Other near-term advanced fossil energy technologies

Besides the advanced technologies described above that are consistent with all sustainable development goals, other near-term advanced fossil energy technologies—for both power generation and synthetic fuels production—offer improved performance relative to today's technologies but would not be consistent with all sustainable development goals. In particular, they would not provide a good basis for moving over the longer term towards near-zero pollutant and CO₂ emissions. Yet some of them might become important in limited applications.

Government support for innovation is needed—particularly for long-term research, and for early deployment of new technologies.

Power generation

Other candidate advanced coal-based power-generating technologies include ultrasupercritical coal steam-electric plants, IGCC plants that employ air-blown gasifiers, and pressurised fluidised-bed combustion (PFBC).

Ultrasupercritical coal steam-electric plants. A typical modern coal steam-electric plant with flue gas desulphurisation has 35.5 percent efficiency (see table 8.4), a level that has changed little since the 1950s. Attention has recently been given to opportunities to achieve higher efficiencies by using advanced alloys that make it possible to increase peak steam temperatures and pressures to ultrasupercritical steam conditions and by deploying efficiency-boosting cycle configurations (for example, double reheating, which increases efficiency by increasing the average temperature at which heat is added to the cycle). For example, ELSAM of Denmark has built a 400-megawatt-electric ultrasupercritical, coal steam-electric plant with an announced efficiency of 47 percent (Kjaer, 1993).⁴⁹ This project should be watched closely to see if operators can avoid the high forced outage rates that plagued earlier attempts to operate steam-electric plants under ultrasupercritical conditions. Increased forced outage risk will be more important under future competitive market conditions than in the past, when most electric companies had a guaranteed rate of return on investment.

One limitation of the technology is that it is not nearly as well suited as the IGCC for cogeneration. The low electricity-heat output ratio characteristic of steam cycles using back-pressure turbines (see figure 8.1) limits the overall cost reduction potential, as well as the overall power-generating and fuel-saving potentials from cogeneration based on this technology (compare tables 8.7 and 8.8). In addition, the cogeneration operating mode is typically not cost-effective for systems that involve steam reheating.⁵⁰

Achieving ultra-low air pollutant emissions will be much harder than for IGCC plants with O₂-blown gasifiers, because contaminants to be removed are in flue gas volumes 40–60 times larger than for the pressurised fuel gases from which pollutants are removed in IGCC plants. In addition, although ultrasupercritical steam plants release a fifth less CO₂ per kilowatt-hour than conventional steam-electric plants, achieving deep reductions in CO₂ emissions requires approaches that involve removing CO₂ from flue gases, which is much more costly than for IGCC plants with fuel gas decarbonisation equipment (see table 8.9).

Coal IGCC technology based on air-blown gasification. Although commercial coal IGCC technology is based on O₂-blown gasifiers, the research and development community is interested in developing systems based on air-blown gasifiers—motivated largely by a desire to eliminate the air separation plant.⁵¹ Interest in air-blown gasification in turn has driven interest in research and development on warm gas clean-up technologies that could reduce the thermal losses from cooling down the gas exiting the gasifier for clean-up and heating it up again for combustion.⁵²

Development of warm gas clean-up is proving to be difficult.⁵³ But even if these difficulties were eventually overcome, broadly based comparisons of O₂- and air-blown gasifier-based systems (Simbeck, 1995) show that O₂-blown gasifiers are usually preferred for coal.⁵⁴ The advantage of avoiding the need for O₂ is offset by disadvantages of air-blown gasifier systems, considering only direct costs. First, because of the lower heating value of the gas, an air-blown gasifier requires twice the gasifier volume as does an O₂-blown gasifier—important in light of the capital intensity of gasifiers. Second, for gasifiers operated at comparable temperatures, the sensible heat of the raw gas leaving an air-blown unit is typically 50–60 percent more than for an O₂-blown gasifier, which implies a significant increase in the duty of the raw gas cooler—one of a gasification plant's more costly items.

In addition, seven strategic considerations amplify the relative benefits of O₂-blown systems. First, O₂-blown gasification facilitates an evolutionary strategy in which gas turbines and combined cycles are fired first with natural gas and converted later to coal as natural gas prices rise—a difficult option for air-blown gasifiers without major system modifications and technical risk. Second, air-blown units are less able to exploit advances in gas turbine technology that enable higher turbine inlet temperatures and higher efficiencies.⁵⁵ Third, with air-blown gasification, polygeneration strategies (see above) other than cogeneration of process heat and electricity are not practical. Fourth, warm-gas clean-up is essential for favourable system economics with air-blown gasifiers, but merely an option that offers higher efficiency for systems with O₂-blown gasifiers—the benefit of which must be traded off against capital cost, reliability, and environmental considerations. Fifth, if warm-gas clean-up can be made commercially viable, environmental benefits would be less for air-blown systems, because dilution of the contaminants with N₂ makes achieving the same levels of air pollutant emissions reduction more costly than for O₂-blown systems. Sixth, achieving deep reductions in CO₂ emissions with IGCCs equipped with air-blown gasifiers would require flue gas CO₂ recovery approaches that are much more costly than are fuel gas recovery approaches for O₂-blown systems (see table 8.9). Seventh, successful development of air-blown gasifier-based systems would not make a major contribution in moving towards near-zero emissions in the long term, while the O₂-blown gasifier is the key near-term technology that would enable this evolutionary strategy.

Pressurised fluidised-bed combustion. PFBC is an advanced technology evolved from atmospheric pressure fluidised-bed combustion (AFBC) technology, which is already on the market (with both bubbling- and circulating-bed variants).⁵⁶

A review of AFBC technology is helpful in understanding PFBC. Although not more energy-efficient than pulverised coal plants, AFBC plants make it possible to use a wide range of coals and other fuels in a single combustor. One manifestation of this fuel flexibility is the ability to cofire coal units with biomass, a common practice

Energy research
and development is cheap
insurance for addressing
the climate change
challenge.

in Scandinavia (Saviharju, 1995). This practice makes it possible both to realise the economies of larger-scale conversion for biomass than are typically feasible with dedicated biomass units and to reduce the AFBC unit's air pollutant and greenhouse gas emissions (as a result of the typically low sulphur and nitrogen contents of biomass feedstocks and their CO₂ emissions neutrality). (This flexibility to accommodate biomass is also provided by fluidised-bed gasification technologies.)

At the low operating temperatures of AFBC plants, thermal NO_x emissions are considerably less than for pulverised coal plants, although about 10 percent of nitrogen in coal can be converted to NO_x (Pillai, 1989). For some coals and in areas with tight regulations on emissions, NO_x control equipment is needed. Up to 90 percent sulphur removal can be accomplished by adding limestone or dolomite to the bed; higher removal rates are theoretically possible but impractical because of the large quantities of limestone and dolomite needed and consequent high solid waste disposal rates. AFBC sulphur removal technology is practically restricted to use with relatively low-sulphur coals and for meeting regulatory requirements calling for relatively modest sulphur removal. The high pH of the waste (because of free lime, accounting for a third of limestone-related wastes) might cause the waste to be classified as hazardous in some areas and thus be subject to especially stringent disposal regulations. Moreover, waste utilisation strategies are difficult because potentially useful products (such as gypsum) are intimately mixed with other wastes.

When a fluidised-bed combustor is pressurised to 10–15 atmospheres, electricity can be produced by feeding the combustion-product gases to a gas turbine after clean-up and using the turbine exhaust gases to produce steam in a heat recovery boiler that drives a steam turbine. Such PFBC technology thus makes higher efficiency possible with a combined cycle, while reducing boiler size. Early PFBC units have 37–40 percent efficiencies. Improved designs, such as ABB Carbon's design with an ultrasupercritical double-reheating PFBC boiler and steam turbine, can achieve 43 percent efficiency.

PFBC and IGCC based on O₂-blown gasifiers are the leading competing advanced coal power technologies. The main PFBC advantages are fuel flexibility (as for AFBC) and simplicity—because PFBC uses one reactor (combustor) relative to two (gasifier and combustor) for IGCC—which might give PFBC a near-term cost advantage. A major PFBC limitation is that, unlike the IGCC, it cannot take advantage of continuing advances in gas turbine technology, because the turbine inlet temperature is fixed at the bed temperature, which is far below the state of the art for modern gas turbines. Future systems might be able to exploit gas turbine technology advances,⁵⁷ although they would not be simpler than IGCC systems and thus would lose the original appeal of the PFBC concept and current designs. Efficiencies of 45–48 percent are being targeted. As in the case of air-blown IGCC technology, successful development of warm gas clean-up technology is key to achieving high performance with future PFBC systems. Like

AFBC, PFBC is limited mainly to use with low-sulphur coals, because of solid waste disposal issues; PFBC typically generates more solid waste per unit of fuel consumed than AFBC.

The higher efficiencies offered by PFBC can lead to reduced CO₂ emissions—for example, a 43 percent efficient unit equipped with an ultrasupercritical double-reheat PFBC boiler and steam turbine would have a fifth less CO₂ emissions than a typical new 35.5 percent efficient pulverised coal plant. But achieving deep reductions in CO₂ emissions would require approaches that involve removing CO₂ from flue gases, which are more costly than for IGCC plants with fuel gas decarbonisation equipment (see table 8.9). In addition, unlike most combustion systems, greenhouse gas emissions from fluidised-bed combustion units can be significantly greater than emissions from fuel carbon. A powerful additional greenhouse gas is nitrous oxide (N₂O), which is produced efficiently from nitrogen in coal at the low operating temperatures of fluidised beds.⁵⁸

Measurements of N₂O in AFBC exhaust gases (de Soete, 1993) correspond to a 5–25 percent increase in CO₂-equivalent greenhouse gas emissions relative to CO₂ emissions from coal burning. Sub-bituminous coals and lignite generally produce less N₂O than bituminous coals, and circulating fluidised beds tend to produce more N₂O than bubbling beds, possibly because of the longer residence times for the former (de Soete, 1993). Reducing N₂O emissions from AFBC units will be technologically challenging. For PFBC systems, N₂O emission data are relatively scant. Measurements at the Swedish Värtan PFBC cogeneration plant (Dahl, 1993) show that emissions vary markedly with operating conditions. From these measurements, it is estimated that when NO_x control technologies are not deployed, the CO₂-equivalent emissions of N₂O emissions are 3–10 percent of CO₂ emissions from coal burning. In addition, when NH₃ injection is used for NO_x control, the CO₂-equivalent emissions are 5–18 percent of CO₂ emissions from coal burning.

Although it is a significant improvement over conventional pulverised coal and AFBC technologies, PFBC technology is limited for the longer term by constraints similar to those for ultrasupercritical pulverised coal steam plants and IGCCs using air-blown gasifiers. For applications involving cogeneration of process heat and electricity, characteristic PFBC electricity-heat output ratios are much less than those for IGCC technologies (because of the relatively minor role played by the gas turbine in PFBC units), so that cogeneration economics would tend to be less favourable than for IGCC systems. And, as for conventional ultrasupercritical pulverised coal steam-electric plants, energy-efficient PFBC designs that employ steam reheat cycles are generally poor candidates for cogeneration. Moreover, PFBC systems cannot exploit the syngas-based polygeneration opportunities feasible with O₂-blown gasification.

Whether PFBC can meet its long-term goals depends critically on success with warm-gas cleanup; comments relating to warm-gas clean-up for PFBC versus IGCC with O₂-blown gasifiers would be

similar to those presented above for warm-gas clean-up for IGCC with air-blown gasifiers versus IGCC with O₂-blown gasifiers. Perhaps the most fundamental shortcoming of PFBC technology is that, as for ultrasupercritical steam technology and IGCC technology with air-blown gasifiers, it is not a stepping stone along the path to near-zero emissions for coal.

Liquid fuels production through direct liquefaction of low-quality feedstocks

An alternative to the indirect liquefaction technology that provides syngas-derived synthetic fuels from carbonaceous feedstocks (see above) is direct coal liquefaction, which involves adding H₂ to coal in a solvent slurry at elevated temperatures and pressures. Direct liquefaction was commercialised in Germany and Japan to provide liquid fuels during World War II, when coal-derived gasoline levels reached 75,000 barrels a day (Simbeck, Dickenson, and Moll, 1981). Interest in the technology virtually disappeared when low-cost Middle Eastern oil became available in the 1950s but was revived during the oil crises of the 1970s, when several pilot and demonstration projects were carried out. Interest almost disappeared again with the collapse of the world oil price in the mid-1980s. Today the technology is again being considered as an option for making synthetic fuels in natural-gas-poor regions such as China.⁵⁹

An advantage often claimed for direct liquefaction is that overall conversion efficiencies are higher than for indirect liquefaction (Stiegel, 1994). However, to the extent that potential efficiency gains relative to indirect liquefaction can be realised, this is largely due to the fact that direct liquefaction plants produce liquids that are aromatic-rich and thus require less H₂ than typical fuels derived through indirect processes (Simbeck, Dickenson, and Moll, 1981). But here an improvement in efficiency would represent a step backwards for environmental management, because new environmental regulations aim to propel a shift to inherently cleaner fuels—for example, recent U.S. regulations limit aromatic contents of transport fuels.

A review of direct coal liquefaction technology by a panel convened by U.S. President Bill Clinton to advise him on energy research and development needs (PCAST Energy Research and Development Panel, 1997) found that the technology:

- Offered no advantages relative to indirect liquefaction.
- Would lead to liquid fuels that generate twice as much CO₂ as petroleum-based fuels.
- Would provide no obvious path to achieving deep reductions in CO₂ emissions over the long term at low cost—in contrast to syngas-based strategies, which can evolve to the point where H₂ is a major energy carrier with low-cost sequestration of the separated CO₂.

Because of such considerations, the panel recommended that the U.S. Department of Energy terminate federal research and development funding for direct coal liquefaction. The panel also recommended that the freed-up resources be used to support research and development on syngas-based technologies that are consistent with a technological evolution over the longer term to near-zero

emissions for fossil fuels.

The arguments set forth here favouring indirect over direct liquefaction apply to other low-quality feedstocks as well as coal—for example, tar sands and heavy crudes, which are far more abundant than conventional oil and natural gas resources (chapter 5). Such feedstocks could be used to produce cleaner fuels through indirect liquefaction, and ultimately H₂ with sequestration of the separated CO₂, thereby helping to realise the long-term goal of near-zero emissions for fossil fuels.

Conclusion

The fossil energy system can evolve in ways consistent with sustainable development objectives if public policies guide a high rate of innovation toward super-clean fossil energy technologies. On the basis of present knowledge, it is possible to identify and describe advanced fossil energy technologies that meet sustainable development objectives at reasonable cost.

The trend towards the growing use of natural gas is making clean energy more widely available at attractive prices. But the move to gas in the context of an increasingly competitive energy industry is also making innovation difficult. To stimulate the needed innovation, policy-makers could set long-term goals for advanced fossil energy technologies, including near-zero emissions of both air pollutants and greenhouse gases. They could also enact policies with incentives to motivate the private sector to develop and deploy technologies that would lead the fossil energy system towards a future consistent with sustainable development objectives.

Key technologies needed to bring about such a fossil energy future are advanced gas turbines, fuel cells, advanced syngas production technologies, and inorganic membranes for gaseous separations. The private sector is fully capable of carrying out most of the needed research and development for all such technologies. But government support for innovation is needed—particularly for long-term research, for which private sector incentives are especially weak, and for early deployment of new technologies that offer major public benefits related to sustainable development (PCAST Panel on ICERD³, 1999).

Major roles for developing countries (where most fossil energy demand growth will take place) in the innovation process are also needed to ensure that innovations are tailored to developing country needs (PCAST Panel on ICERD³, 1999). Government also could play a role in guiding and facilitating new infrastructure development—for example, for natural gas delivery systems in the near term and H₂ delivery systems in the long term. Both the energy innovation process and infrastructure-building activities have strong international dimensions and highlight the importance of fostering international collaborations—for example, through industrial joint ventures (PCAST Panel on ICERD³, 1999).

Reforms that encourage competitive power markets could help put industry on a path to fossil energy with near-zero emissions by helping launch syngas-based polygeneration activities that provide clean synthetic fuels for transportation, cooking, and other applications, along with electricity and process steam.

Two sets of research and development issues stand out for a long-term fossil energy strategy. One concerns the effectiveness, safety, and capacity for CO₂ disposal. A better scientific and technical understanding of these issues, on a region-by-region basis, would help policy-makers decide how much climate-change mitigation resources to commit to this strategy relative to other options, such as renewable or nuclear energy. The other concerns the prospects for energy recovery from methane hydrates. A better scientific and technical understanding of this resource, on a region-by-region basis, would help policy-makers decide how to allocate resources for long-term fossil energy research and development (for example, how to allocate between coal and methane hydrate options). Getting answers to both sets of questions would require expenditures of public resources, because private sector interest is weak as a result of the long-term nature of the questions. But in both cases, the required expenditures are likely to be modest.

An uncertainty regarding the strategy outlined here—guiding the fossil energy system towards widespread fuel decarbonisation with CO₂ sequestration—is whether the public will find large-scale sequestration acceptable. The public has to be convinced that sequestration will be safe and effective. Broad public participation in activities related to decarbonisation and sequestration should be encouraged—for example, a wide range of stakeholder groups should have roles in reviewing scientific studies, demonstration projects, and planning activities. The fact that the least costly technologies for CO₂ disposal also offer near-zero emissions of air pollutants should help gain public confidence. The public will want to know the trade-offs, in relative costs and side effects, among fossil, renewable, and nuclear options for realising the goal of near-zero emissions, and also the trade-offs between pursuing near-zero emissions and not doing so.

ADVANCED NUCLEAR ENERGY TECHNOLOGIES

Nuclear power dominates electricity production in several countries⁶⁰ and is making substantial contributions to global energy: At the 1998 level of installed nuclear capacity of 349 gigawatts-electric, nuclear power provided 16 percent of world-wide electricity (IAEA, 1999). Although there is likely to be modest expansion until 2010, most projections are that the nuclear share of electricity generation will be less in 2020 than today. And many projections envisage that nuclear power's absolute contribution in electricity will be no more than today and might even be less.⁶¹

The regional outlook has more contrasts.⁶² For industrialised countries, which accounted for 81 percent of nuclear generating capacity in 1997, the U.S. Energy Information Administration (EIA) projects that nuclear capacity in 2020 will be 44, 75, and 100 percent of the capacity in 1997 for its low-growth, reference, and high-growth scenarios. The projected reductions in capacity in industrialised countries reflect the expectation that nuclear plants retired at the ends of their useful lives will not be replaced, although utilities in several countries are considering plant life extensions. For Eastern Europe and the countries of the former Soviet Union (which accounted for 13 percent of global nuclear capacity in 1997), the EIA projects that, for these same scenarios, capacity in 2020 will be 26 gigawatts-electric less, 6 less, and 24 more than in 1997. For developing countries (which accounted for 6 percent of global nuclear capacity in 1997), the EIA projects capacity increases for the respective scenarios of 10, 34, and 67 gigawatts-electric, with most of the expansion in Asia.

There is a nuclear power stalemate in many regions, in part because the technology is much more costly than was originally projected—a problem exacerbated by low fossil fuel prices, growing

numbers of new competing technologies, and increasingly competitive market conditions world-wide in the electric power industry. In addition, the prospects for continuing and expanding the contribution of nuclear power to the world energy supply have been clouded by concerns related to safety, radioactive waste management, and nuclear weapons proliferation and diversion. All these issues have led to a loss of public confidence in nuclear technology.

Rationale for reconsidering the nuclear option

If ways can be found to make nuclear power widely acceptable, it could help address problems posed by conventional fossil energy technologies—especially health impacts of air pollution and climate change arising from CO₂ build-up in the atmosphere. Considering the chain of activities for nuclear power production (including mining operations, nuclear fuel conversion, nuclear power plant operation, decommissioning, transportation, and waste disposal), recent analysis carried out under the European Commission's ExternE Program estimated that the total cost of environmental damage (local, regional, and global impacts integrated during a period of up to 100,000 years) is about \$0.003 per kilowatt-hour when evaluating future impacts with a zero discount rate (Rabl and Spadaro, 2000).⁶³ This is far less than the environmental damage costs of coal steam-electric plants with the best available control technologies, but (considering the margin of error in these estimates) is comparable to damage costs of modern natural gas combined cycle and coal IGCC plants (see table 8.1).

These externality cost comparisons for nuclear and fossil energy systems are incomplete, however. The calculations do not take into

Most projections are that the nuclear share of electricity generation will be less in 2020 than today.

account costs associated with the potential diversion of nuclear materials to weapons purposes or wars triggered by concerns about access to energy or water supplies, which are inherently difficult to quantify in economic terms. For nuclear power, greenhouse gas emissions are zero, a benefit (also inherently difficult to quantify) that must also be taken into account in comparing nuclear and fossil energy technologies.

As an aid in thinking about potential roles for nuclear energy in mitigating climate change, consider two alternative scenarios:

- A high-growth scenario that extrapolates the EIA's high-growth scenario to 2100, with nuclear capacity increasing to 1,000 gigawatts-electric by 2050, 3,000 by 2075, and 6,500 by 2100.⁶⁴
- A low-growth scenario that extrapolates the EIA's low growth scenario to zero nuclear capacity by 2050.

The greenhouse gas mitigation benefit of the high-growth relative to the low-growth scenario would be reductions in CO₂ emissions of 225 GtC during the next 100 years if coal power were displaced and 110 GtC if natural gas power were displaced⁶⁵—reductions equivalent to 16 percent and 8 percent of emissions during the period under a business-as-usual future.⁶⁶ This calculation shows that, for nuclear energy to make a significant contribution to coping with climate change, nuclear capacity must be increased by at least an order of magnitude during the next 100 years.

The need for advanced technologies

It is desirable to see if acceptable solutions can be found to the economic, safety, proliferation and diversion, and waste management concerns that presently constrain the prospects for further nuclear deployment.⁶⁷ Solutions are desirable both because nuclear energy can potentially contribute to solving the major problems posed by conventional fossil energy technologies and because of uncertainties associated with the prospects of other advanced energy-supply options (both the advanced fossil technologies described above and the renewable technologies described in chapter 7). Emphasis here is on technological strategies and the kinds of research and development that offer promise in making the nuclear option more attractive. However, socio-political considerations are also discussed.

The sociopolitical context

Identification of promising technologies for future nuclear power is complicated by the lack of consensus in the broader community of stakeholders (utilities, governments, publics, scientists, engineers) on goals for nuclear energy innovation and ways to address the goals. At the root of these difficulties is the fact that the issues cannot be resolved in narrow technical and economic terms. Perceptions of costs, safety, proliferation and diversion impacts, and risks in waste management matter as much as engineers' calculations.

To illustrate, consider that although most experts believe waste disposal is the least challenging problem facing nuclear energy and

is soluble, many in the general public regard waste disposal as the most daunting challenge. Public concerns about managing wastes for the very long term thus have focused attention in the technical community on waste mitigation strategies that could radically shorten the time required to keep waste under surveillance (for example, nuclear waste separation and transmutation proposals)—relatively costly strategies that some experts believe would exacerbate proliferation and diversion concerns without gaining many benefits. As long as there are such seemingly fundamental disagreements, nuclear energy innovation efforts will remain unfocused.

The analysis of technologies and strategies that follows is based largely on technical considerations. But the reader should bear in mind that bringing about a 'nuclear renaissance' would require more than just doing the right research and development. Because—after an ambitious start—nuclear power has lost its lustre, the barriers to its revival are probably higher than if the technology were entirely new. Nuclear power may never again be seen as "a welcome sign that the modern age is dawning; it can at best hope to be tolerated. Therefore, nuclear power must have a substantial advantage if it is to be used" (Lidsky, 1991). And new nuclear technology must appeal not only to experts but also to the public.

Nuclear electricity costs

Nuclear fuel costs are low relative to fossil fuel costs. For example, in 1998 the average fuel cost for nuclear power in the United States was \$0.0054 per kilowatt-hour (Ryan, 1999)—a third that for coal steam-electric power and a fourth that for natural gas combined cycles in Europe (see table 8.4). But operation and maintenance costs and capital costs have been high for nuclear plants. Operation and maintenance costs have been declining somewhat in recent years as a result of competitive pressures but are high relative to operation and maintenance costs for fossil fuel plants. For example, in 1998 operation and maintenance costs for U.S. nuclear plants averaged \$0.014 per kilowatt-hour (Ryan, 1999)—more than three times the operation and maintenance cost for U.S. coal or natural gas plants (see table 8.4). Operation and maintenance costs have been high for nuclear plants largely because of the large operating staff—typically 800–900 for a large 1,100-megawatt-electric power station. Staffing requirements are high, to a large degree because of the need to operate the plants within current regulatory guidelines designed to ensure safety.

A recent survey of electricity generation costs in 18 countries found that installed capital costs for new nuclear power plants around the world are \$1,700–3,100 per kilowatt-electric (Paffenbarger and Bertel, 1998),⁶⁸ much higher than for typical new fossil energy plants. Despite such high capital costs, the study found that, for new plants, nuclear power would be less costly than coal- or natural-gas-based power in two countries—China and France.

For nuclear energy to qualify as a sustainable energy option, concerns regarding safety, waste disposal, and proliferation must be addressed in ways that enable it to compete on an economic basis.

The costs of alternatives to nuclear power are fast-moving targets in many regions. Privatisation is taking place in many countries where the power sector was once dominated by parastatal energy companies, and the trend is towards more competition in power markets, where competitive new smaller-scale technologies have ended the historical natural monopoly status of electricity generation. As noted, the natural gas combined cycle has become the technology of choice for thermal power generation where natural gas is readily available. Where competitive conditions are strong, costs have been coming down, even for mature technologies such as pulverised coal steam-electric plants—for example, by a fourth in the United States from 1992–95 (Stoll and Todd, 1996).

Moreover, since the early 1980s the average price of coal for electric companies in the United States has fallen by a factor of 2 in real (inflation-adjusted) terms, and the average coal price is expected to fall a further 30 percent by 2020, to \$0.90 a gigajoule (EIA, 1999a). In Europe fossil energy prices are not as low as in the United States, but even there prices have been falling; from 1983–95 the average prices for coal and natural gas imported into the European Union fell from 55 to 65 percent (Decker, 1999). Such intensifying competition from fossil fuels can be expected to spread to more and more regions undergoing electric industry restructuring.

Quantification of the external costs of today's fossil energy plants would improve the economics of nuclear power. But these benefits will not be so great with various advanced fossil energy technologies: Fossil energy technologies now coming onto the market can provide electricity with very low emissions of local and regional air pollutants. Moreover, as discussed above, even the climate change benefits offered by nuclear power likely will face stiff competition from advanced coal systems that involve fuel decarbonisation and CO₂ sequestration. Thus direct economic costs will continue to be important in determining the future of nuclear power. If nuclear power is to become economically viable once again, innovations will be needed that can provide electricity at costs competitive with other future near-zero-emission energy technologies. Moreover, this has to be done in ways that are consistent with meeting concerns about nuclear safety, proliferation and diversion, and radioactive waste disposal.

Nuclear safety

If substantial quantities of the radionuclides produced in nuclear reactors are released to the environment, the result can be considerable damage—not just the direct impacts on people and the environment but also the indirect impacts on the viability of the industry itself. The loss-of-coolant accident at Three Mile Island shook investor confidence in nuclear power, even though radioactive material releases to the environment were minimal. As a result of the Chernobyl accident, the public has little confidence that nuclear power is safe.

Unlike Chernobyl-type reactors, the light water reactors (LWRs) that dominate nuclear power around the world have had a remarkably good safety record. But LWR accidents can happen. The Three Mile Island accident stimulated numerous improvements in reactor safety. Detailed calculations

indicate that, for current U.S. reactors, the probability of core damage is less than 10^{-4} per reactor per year, and the probability of significant radioactive releases is a tenth as large (Fetter, 1999). But this record has been achieved at a high cost for a complex technology to minimise serious accident risk, and the technology is unforgiving of error.⁶⁹

Advanced reactors are likely to be significantly safer. Two approaches to safety are used in advanced reactor designs. One is aimed at improving the technology in an evolutionary manner with the present defence-in-depth approach to safety, which provides redundancy or multiple levels of active interventions by equipment and operators to prevent fuel damage—and, even if fuel is damaged, to prevent the release of significant quantities of radioactivity to the environment. Although enough redundancy can reduce the probability of failure to arbitrarily small values, sceptics can always claim that not all events leading to accidents can be imagined, so that the probabilities used in probabilistic risk assessment are not accurate (Spiewak and Weinberg, 1985). Such systems depend on proper operation and maintenance of reactors, which cannot always be assured.⁷⁰

The complexity of active safety systems also can tempt workers to ignore regulations they believe to be overly conservative (as was the case at Chernobyl). And finally, complex systems can make it difficult to achieve the goal of reducing capital and operation and maintenance costs. An alternative approach to safety is to identify and develop technologies that offer a high inherent degree of safety without the need for complicated, capital-intensive safety controls—often called passive safety systems. If passive systems can be developed and made to work effectively, they offer the potential to address safety and cost challenges simultaneously. Lidsky (1991) argues that new reactor technologies have to be not only safe but demonstrably safe, because “the public has lost faith in all experts and has little trust in probabilistic risk assessments”.

Nuclear proliferation and diversion

The knowledge needed to design and fabricate fission bombs is available to almost every nation. For many years, lack of access to nuclear explosive materials,⁷¹ not lack of knowledge, has been the main technical barrier to the spread of nuclear weapons capability. The essence of the potential nuclear weapons link to fission power (box 8.5) is that this technology provides the possibility of obtaining this missing ingredient, in the form of either uranium-enrichment capability or plutonium extractable from spent reactor fuel through chemical reprocessing. Access to such materials makes it easier for additional countries to acquire nuclear weapons (Holdren, 1989).

In the future, as sub-national criminal groups become more sophisticated, the related threat that these too might acquire nuclear bombs or radiological weapons by misusing nuclear energy technologies may grow in importance (Willrich and Taylor, 1974; Leventhal and Alexander, 1987; LLNL, 1998).

Are proliferation and diversion resistant technologies needed?

A multifaceted effort is required to minimise the motivations for proliferation: control commerce in sensitive facilities, equipment, and materials; detect any misuse of such facilities or equipment or diversion of materials; and intervene where necessary to prevent an errant nation or sub-national criminal group from acquiring nuclear weapons. The main approach to addressing these challenges has been the Nuclear Non-Proliferation Treaty and associated international safeguards and nuclear supplier agreements (box 8.6). These deterrents are more significant than ever before: A nation-state deciding to launch a nuclear weapons programme today would need to find motivation sufficient to offset the penalties of discovery, the possibilities that the enterprise might not succeed, and costs that might be prohibitive.

The issue of how to deal in the future with the risk that nuclear materials in civilian nuclear power programmes will be used for weapons purposes is a focus of debate. One view is that this risk can be adequately addressed by a system of institutional controls, building on the historical success of the Nuclear Non-Proliferation Treaty (Walker, 1999). Others argue that if the role of nuclear energy were to expand substantially (for example, to the extent that nuclear power could have a significant role in mitigating climate change risks), the requirements imposed on institutional measures such as safeguards would increase significantly. Thus, it is argued, research and development is needed to see if the inherent resistance of nuclear energy systems to proliferation can be increased, thereby lessening the intensity of reliance on institutional measures alone to reduce proliferation risks (Bunn, 1999; Feiveson, 1999; Williams and Feiveson, 1990; PCAST Energy Research and Development Panel, 1997; PCAST Panel on ICERD³, 1999).⁷²

Clearly, additional countries can acquire nuclear weapons if they want them badly enough to openly abrogate the Nuclear Non-Proliferation Treaty or to take their chances that a clandestine weapons programme will not be detected. And such countries can do this whether or not civilian nuclear energy technology is available to them as a partial basis for their weapons effort. It appears that the steps taken to strengthen the non-proliferation regime in recent years have significantly increased the difficulty, cost, and detectability of such efforts to produce nuclear weapons.

Looking to the future, the key proliferation and diversion issue is how to minimise the temptations and advantages that nuclear programmes may offer potential proliferator states and sub-national groups—that is, how to minimise any contribution of nuclear energy to the rate at which additional states or groups seek to acquire and succeed in acquiring nuclear weapons.

The sections below explore the prospects for reducing proliferation

and diversion risks with advanced technologies, which could be especially important in a world where nuclear power is developed on a scale far larger than at present.⁷³ Two approaches to proliferation and diversion resistance are considered. One involves systems in which plutonium and other weapons-usable materials are never separated from spent fuel, the radioactivity of which deters proliferation and diversion efforts. These systems build on the fact that contemporary light-water reactors using low-enriched uranium in a once-through

BOX 8.5. NUCLEAR WEAPONS PROLIFERATION RISKS POSED BY NUCLEAR ENERGY TECHNOLOGIES

Nuclear explosives can be made both from highly enriched uranium and plutonium, including plutonium produced in civilian nuclear power plants. Although there are complications in weapon design, fabrication, and maintenance when reactor-grade instead of weapons-grade plutonium is used, these do not add substantially to those that must be faced when using any nuclear-explosive material for making weapons, according to individuals and groups with authoritative knowledge of nuclear weapons technology (Holdren, 1989; Mark, 1993; CISAC, 1994, 1995). Reactor-grade plutonium can be used to construct devastating nuclear weapons at all levels of technical sophistication (DOE, 1997). So that the dangers of reactor-grade plutonium will not continue to be misunderstood, in recent years the U.S. Department of Energy (custodian of the world's most sophisticated knowledge base on the subject) has made this point clear in unclassified reports and has allowed those with DOE nuclear-weapon security clearances to make explicit statements about it in other forums. Especially relevant points are made in the following quotations:

The difficulties of developing an effective design of the most straight forward type are not appreciably greater with reactor-grade plutonium than those that have to be met for the use of weapons-grade plutonium. (Mark, 1993)

Using reactor-grade rather than weapons-grade plutonium would present some complications. But even with relatively simple designs such as that used in the Nagasaki weapon—which are within the capabilities of many nations and possibly some subnational groups—nuclear explosives could be constructed that would be assured of having yields of at least 1 to 2 kilotons. With more sophisticated designs, reactor-grade plutonium could be used for weapons having considerably higher minimum yields. (CISAC, 1994)

At the other end of the spectrum, advanced nuclear weapon states such as the United States and Russia, using modern designs, could produce weapons from reactor-grade plutonium having reliable explosive yields, weight, and other characteristics generally comparable to those of weapons made from weapons-grade plutonium. (DOE, 1997)

Although there are more direct ways for a country to acquire nuclear bombs than from its commercial nuclear energy facilities (for example, centrifuges for uranium enrichment and special reactors dedicated to plutonium production), the acquisition of nuclear explosive materials is made easier if the requisite technical skills and infrastructure are already in place through a nuclear power programme. The existence or prospect of commercial nuclear power in a country, moreover, provides a legitimating cover for nuclear activities that, without electricity generation as their manifest purpose, would be considered unambiguously weapons-oriented and thus potentially subject both to internal dissent and external sanctions and counter-measures. Feiveson (1978) points out that even countries that initially have no intention of acquiring nuclear weapons might later be more likely to acquire them, under altered internal or external political circumstances, because their having a nuclear power programme has made it easier to do so.

BOX 8.6. INSTITUTIONAL MECHANISMS ADDRESSING PROLIFERATION RISKS OF NUCLEAR ENERGY

International efforts to stem the spread of nuclear weapon capabilities have been more successful than almost anyone at the beginning of the nuclear era dared to hope. Rather than the dozens of nuclear weapon states once predicted, today only eight states are believed to have nuclear weapons capabilities, a number that has not increased for more than 10 years. Indeed, South Africa has provided the first case of genuine nuclear disarmament—a state that had full control over its own arsenal of nuclear weapons and agreed to give them up entirely. The international regime that has achieved this result includes both political elements designed to convince states that acquiring nuclear weapons is not in their interest, and technical elements designed to increase the detectability, difficulty, and cost of nuclear weapons acquisition. The foundation of this regime is the Nuclear Non-Proliferation Treaty, which now has 187 parties—more than the United Nations Charter. The civilian nuclear energy programmes of all of these besides the five nuclear-weapon states recognised by the treaty are subject to ‘full scope’ IAEA (International Atomic Energy Agency) safeguards designed to verify their commitments not to acquire nuclear weapons.

Several parts of the non-proliferation regime are designed to address the nuclear weapons proliferation risks posed by civilian nuclear energy programmes. The most fundamental part is IAEA safeguards, which allow international verification of the peaceful use of all nuclear materials in non-nuclear-weapon states (OTA, 1995). In the aftermath of the post-Gulf War revelation of Iraq’s large-scale clandestine nuclear weapons programme, and the failure of previous IAEA monitoring and inspections to detect it, IAEA safeguards are being substantially strengthened, with new measures designed not only to verify that nuclear material

at declared sites is not misused, but also to help ferret out activities that may be taking place at secret sites (Hooper 1997). Other critically important institutional measures to reduce the risk of proliferation include the international system of controls on exports of technologies that could be used for nuclear weapons programmes, as well as programmes to ensure that all potentially weapons-usable nuclear material is secure and accounted for—and so cannot be stolen for use in nuclear weapons by proliferating states or terrorist groups.

But confidence in the future effectiveness of the non-proliferation regime in general, and the barriers to use of nuclear-energy technologies for proliferation in particular, cannot be unconditional or complete. The non-proliferation regime itself is imperilled by the recent efforts in this direction by Iraq and the Democratic People’s Republic of Korea, and by the failure of the recognised nuclear-weapon states (above all, Russia and the United States) to move more decisively, in the aftermath of the cold war, towards fulfilling their legal obligation under Article VI of the Nuclear Non-Proliferation Treaty to negotiate in good faith towards nuclear disarmament (Barletta and Sands, 1999). The extensively documented case of Iraq, in particular, demonstrates that eternal vigilance is required to prevent states from clandestinely acquiring critical technologies despite the existence of export controls on them.

Moreover, the safeguards implemented by the IAEA—which include monitoring of records and on-site inspections at reactors and fuel-cycle facilities, along with the broader measures beginning to be implemented in the aftermath of the Gulf War—at best only provide assurance that diversion of nuclear materials to weaponry will be detected. These safe-

guards are not intended to prevent such diversion, or to prevent theft of these materials by sub-national groups. (Protection against theft is the province of individual states; there are no binding international standards governing the adequacy of such protection, and levels of protection vary world-wide from excellent to grossly inadequate.) Even detection of diversion or theft is not completely assured, both because of limitations on the resources being provided to the IAEA and because of the intrinsic difficulty of the task of safeguarding nuclear materials, particularly when large quantities of weapons-usable nuclear material are being processed in bulk.

This difficulty has been recognised since the dawn of the nuclear era. Addressing the adequacy of international inspections for the purpose of preventing nuclear proliferation, the Acheson-Lillienthal Report that formed the basis of the Baruch Plan for international control of nuclear weapons (submitted to the UN by the United States in 1946) stated that “there is no prospect of security against atomic warfare in a system of international agreements to outlaw such weapons controlled only by a system which relies on inspection and similar police-like methods. The reasons supporting this conclusion are not merely technical but primarily the inseparable political, social, and organizational problems involved in enforcing agreements between nations, each free to develop atomic energy but only pledged not to use bombs...So long as intrinsically dangerous activities may be carried on by nations, rivalries are inevitable and fears are engendered that place so great a pressure on a systems of international enforcement by police methods that no degree of ingenuity or technical competence could possibly cope with them” (Lillienthal and others, 1946).

fuel cycle that leaves the plutonium mixed with fission products in spent fuel are the most prominent operational example of a relatively proliferation-and-diversion-resistant fuel cycle. An improved variant of this approach is advanced once-through reactor and fuel cycle technologies for which the quantities of weapons-usable materials available in spent fuel are reduced—thereby reducing incentives to mine spent fuel for weapons-usable materials. A completely different approach is to convert nuclear energy to electricity and hydrogen in large international energy parks at which weapons-usable materials are maintained under tight international control and to distribute these carriers to distant consumers. The next subsection discusses proliferation and diversion issues associated with nuclear fuel reprocessing and plutonium recycling for today’s civilian nuclear power technology.

Nuclear fuel reprocessing and plutonium recycling. Several countries have begun commercial-scale reprocessing to recover plutonium along with unused uranium from spent fuel (with

intentions to dispose of the separated radioactive wastes in geologic repositories at a future date) and to recycle plutonium in mixed-oxide uranium-plutonium (MOX) fuel for IWRs. These activities make the nuclear weapons proliferation risk a more serious concern than when IWRs fuelled with low-enriched uranium are operated on once-through fuel cycles.

Commercial IWR fuel-reprocessing systems have been established in France (at La Hague), Russia (Chelyabinsk-Ozersk), and the United Kingdom (Windscale-Sellafield).⁷⁴ These facilities are nodes of a global nuclear fuel management system in which spent fuel is sent from reactors to reprocessing plants, and the separated constituents (uranium, plutonium, radioactive wastes) are to be returned (eventually) to the fuel owners.⁷⁵ These three sites are reprocessing fuel from about 150 reactors operating in nine countries (Berkhout, 1998).

Reprocessing facilities now handle a fourth of the spent fuel discharged from power reactors. The rest is in interim storage,

either targeted for eventual geological disposal in canisters designed for direct disposal without reprocessing, or (for the majority of the material outside Canada and the United States) pending a decision on whether to go to geological storage or reprocessing. Today 20 tonnes of plutonium is being separated from spent fuel annually world-wide; by the end of 1995, 180 tonnes had been separated from civilian nuclear reactor spent fuel—18 percent of the total plutonium discharged from these reactors (Albright, Berkhout, and Walker, 1997). Some of the recovered plutonium and uranium mixed with fresh uranium (MOX fuel) is being used as fuel for LWRs. The challenge of managing the growing stockpile of separated civilian plutonium (the total quantity separated less the amount used as fuel in plutonium recycling, about 180 tonnes world-wide as of 2000) parallels the problem of managing the growing quantity of separated surplus military plutonium produced by dismantling excess nuclear weapons in the aftermath of the cold war, now approaching 100 tonnes in Russia and the United States combined (PCAST Panel on ICERD³, 1999).

Although it reduces uranium requirements for power generation, the reprocessing-recycling option does not compete in economic terms with once-through use of low-enriched uranium fuel in LWRs,⁷⁶ reflecting the fact that it has become clear that the world has large, low-cost reserves of uranium (chapter 5). Yet reprocessing and recycling activities continue for a number of reasons: sunk capital costs, government subsidies, long-term contracts signed when uranium seemed scarcer and costlier, reluctance to throw away the energy content of unrecycled plutonium and uranium, perceptions that reprocessed wastes are easier to manage than spent fuel, and lack of alternatives to reprocessing as a means of removing spent fuel from reactor sites in the short term (PCAST Panel on ICERD³, 1999).

Nuclear waste disposal

The radioactive by-products of fission must be isolated from the human environment to the extent that they can never return in concentrations that could cause significant harm. Spent fuel removed from a reactor is first stored for at least a few years in cooling pools at the reactor site. After the very short-lived fission products have decayed, the fuel can:

- Remain in the pools (if they have sufficient capacity).
- Be stored on-site in dry casks (which provide a safe and economic alternative for storage for several decades).
- Be transported to an away-from-reactor storage site (either pools or dry casks).
- Be transported to a reprocessing plant or a geologic disposal facility.

In many cases efforts to expand long-term storage capacity on-site or particularly to establish large away-from-reactor stores not associated with reprocessing or disposal sites have encountered public opposition, leaving some utilities in doubt as to where to put their spent fuel as their cooling ponds fill up.

Eventually, the spent fuel will either be reprocessed, and the high-level wastes sent to a long-term storage site, or it will be encapsulated in suitable canisters and sent directly to a long-term disposal site.

Safe ways of storing wastes for periods up to 1 million years may be required. For the first hundred years of the required isolation period, the radioactivity and heat of these wastes are dominated by fission products. After several hundred years, the major concerns are the very-long-lived transuranics (various isotopes of plutonium, neptunium, and Americium) and long-lived iodine and technetium fission products.

There is a consensus among states using nuclear energy that deep geologic disposal in mined repositories is the best currently available approach for disposal of nuclear wastes.⁷⁷ And most experts believe that geologic repositories can be designed to be safe (NEA, 1999). However, to date, no country has yet disposed of any spent fuel or high-level waste in such a repository.

Because wastes are concentrated, disposal cost is not a significant issue. In the United States, for example, utilities are charged only \$0.001 per kilowatt-hour for management and disposal of their spent fuel (2–3 percent of generation cost). Detailed calculations suggest that this will be fully adequate to finance that portion of the cost of the nuclear waste disposal programme attributable to civilian spent fuel (DOE, 1998). Costs would be higher for small countries if repositories were established there to accommodate only their own wastes.

Public and political opposition to waste disposal has delayed efforts to open targeted repositories in some countries. There have also been technical problems. But long-term waste disposal should not be an intractable problem from a technical perspective. Even if some wastes eventually leak from repositories, problems would be manageable because of the small storage space required.

For example, storage density limits for spent LWR fuel at Yucca Mountain, Nevada, are 41 square metres per megawatt-electric of nuclear generating capacity for a power plant operated for 30 years (Kadak, 1999). At this storage density, the area required for storing all radioactive waste generated during the 21st century for the global high-nuclear-growth scenario above is 270 square kilometres. Suppose that a waste-isolation land area 10 times as large is purchased at a cost of \$100,000 per hectare to be maintained in perpetuity with no human intrusion. The required land area is 0.003 percent of the continental land areas. The cost of the land would be \$0.0009 per kilowatt-hour generated (2 percent of generation cost) for a 10 percent discount rate, or \$0.00002 per kilowatt-hour (0.05 percent of generation cost) for a 0 percent discount rate, assuming in both cases that the land is paid for in 2000.

Because the areas required are modest, it is not necessary for every country to develop its own repository. Globally, only a small number of sites is needed. Restricting storage to a small number of favourable sites around the world would be attractive for various reasons (McCombie, 1999a, b; McCombie and others, 1999; Miller and others, 1999), including realisation of scale economies, the potential for optimising the prospects for achieving demonstrable safety, and various additional reasons discussed below.

Although coping with the radioactive waste problem seems manageable from a technical perspective, a technical fix by itself is

Effectively addressing nuclear concerns probably requires advanced technologies as well as improved institutional risk management strategies.

not a solution: A real solution has many non-technical features as well (see below).

Must spent fuel be reprocessed for radioactive waste disposal? At one time, it was thought by some that reprocessing is needed to safely dispose of radioactive wastes. However, the International Fuel Cycle Evaluation, carried out from 1977–79 to consider the commercial use of plutonium, concluded that spent fuel itself could be safely disposed of in a waste repository (STATS, 1996). This conclusion has been strengthened by subsequent intensive investigations of spent fuel disposal in several countries (for example, Finland, Sweden, and the United States).

Nevertheless, both public opposition to interim away-from-reactor storage sites and delays in opening long-term waste repositories are causing great difficulties for utilities, because storage pools at reactor sites are fast approaching capacity. In some countries (not the United States, which has abandoned civilian reactor fuel reprocessing), nuclear utilities have been forced into reprocessing as a de facto interim waste management strategy. But reprocessing does not solve the waste disposal problem—it merely buys time and transforms the spent fuel management problem into several other problems associated with plutonium disposition: management of high-, medium-, and low-level wastes at reprocessing plants; management of transuranic wastes at plutonium fuel fabrication plants; and, eventually, decommissioning wastes from these plants (plus residual spent-fuel disposal, if plutonium is not recycled indefinitely).

Should long-lived wastes be separated and transmuted? The challenge of storing the very-long-lived components of radioactive wastes has led to various separations and transmutation (S&T) proposals for separating out the hazardous, long-lived components and transmuting them by neutron bombardment to form nuclides that would be either stable or radioactive with much shorter half-lives. The Committee on Separations Technology and Transmutation Systems (STATS) was formed by the U.S. National Research Council at the request of the U.S. Department of Energy to evaluate alternative S&T options for addressing such issues and assess their implications for nuclear waste management.

The STATS committee investigated several alternative reactor and particle accelerator systems. It found that, although S&T might be technically feasible for some of the options studied, the need for permanent long-term storage would remain. Many decades to centuries would be required to reduce the radioactivity to the low levels specified by S&T proponents as their objective, and disposal costs would increase substantially (STATS, 1996).⁷⁸ Moreover, it is unlikely that the modest reduction in waste-disposal risk for the long term (which is already very small) would outweigh the high costs and increased near-term accident and proliferation risks that would be associated with S&T (Fetter, 1999). The most active programmes in this area are those of France, Japan, Russia, Sweden, and the United States.

Towards geological disposal. As noted, the focus world-wide for

long-term disposal is on geologic repositories. All concepts rely on multiple barriers provided by the storage canisters, the backfill material used to surround the canisters in the storage rock, and the rock itself. Test results suggest that corrosion-resistant containers may be able to keep nearly all the waste contained for thousands of years.

There have been setbacks, though not always for scientific and technical reasons; public and political opposition has sometimes slowed technical progress. In the United States, public acceptability considerations led Congress to choose the Yucca Mountain site in sparsely populated Nevada, even though technically it may not be an especially good site (Fetter, 1999).⁷⁹

Advances in waste disposal science and technology have been rapid in Sweden, where the decision to phase out nuclear power facilitated a societal consensus on a waste disposal programme (Gillena, 1994). Swedish researchers are developing a scheme to put spent fuel in copper-clad steel canisters to be embedded in bentonite clay in a granite monolith 600 metres underground at a site near the sea; they anticipate a million-year canister lifetime for the site's reducing conditions (Whipple, 1996). Should the storage canisters eventually leak, surrounding backfill material and rock would inhibit movement of leaked wastes to the surface.

The widely shared judgement of the technical community that long-term storage can be made safe is based on careful assessments of safety and environmental impacts that take into account both waste characteristics and the properties of all barriers involved. Several extensive safety assessments have been carried out in OECD countries. Potential radiation exposures have been calculated to be close to zero for periods of 100,000 years for all scenarios and sites considered; for longer periods, the risks are so small as to impose very small additional externality costs, even if there is no discounting for these uncertain remote future events.⁸⁰

Technical uncertainties need further study.⁸¹ But none is likely to be a show-stopper. Moreover, there is time to resolve technical issues because, from a technical perspective, there is no urgency to move wastes from interim to permanent long-term storage sites. In fact, delay for a period of 50 years would not only buy time to improve scientific understanding of long-term storage issues and storage technology, but would also facilitate waste disposal by reducing required heat removal rates as a result of radioactive decay of fission products. Delaying long-term waste disposal would probably require establishing secure storage sites (which might be the same as the long-term disposal sites) for spent fuel for part of this cooling off period; but, as recent experience has shown, this will not be easily accomplished in the political arena.

Will spent fuel repositories become plutonium mines? A final technical waste disposal issue relates to the concern that, if radioactive wastes are stored as spent fuel rather than reprocessed wastes, repositories might one day be mined as sources of low-cost plutonium for nuclear weapons. The Committee on International Security and

Arms Control of the U.S. National Academy of Sciences has identified general proliferation hazards associated with spent fuel management, including the issue of mining waste repositories for plutonium recovery, as an area warranting continued research “at the conceptual level” (CISAC, 1994).

Peterson (1996) has argued that, after a hundred years or so, the costs of clandestine tunnelling into spent fuel repositories to recover plutonium would be less than the costs for conventional dedicated facilities to acquire plutonium. In examining this issue, Lyman and Feiveson (1998) found that the range of conditions under which repository mining would look attractive relative to other means of acquiring plutonium is narrow. Although safeguards would be needed in perpetuity, the measures needed to deter mining need not involve expensive and intrusive inspections but could focus on containment and surveillance procedures, including remote monitoring by satellites. And the safeguard management challenge would be greatly facilitated if there were only a small number of repositories around the world.

Perspective on radioactive waste disposal. The most important unresolved issues relating to radioactive waste disposal are political rather than technical. Providing adequate disposal capacity for nuclear wastes has been and is likely to continue to be fraught with political controversy.

The world would be better off if secure, internationally managed, interim, away-from-reactor storage sites could be set up for spent fuel, even for periods of 50 years before activating any permanent repository. If such interim storage capacity were to become available, fewer and fewer utilities would be willing to pay the extra near-term costs of reprocessing, and the reprocessing industry would slowly be competed out of business. Yet the world is not moving in this direction. As noted by Häckel (1997):

The historical record of the past decades is littered with the acronyms of defunct proposals for an internationalised back end fuel cycle... Not only have these not materialised; it appears that at the back end of the fuel cycle internationalisation is actually on the retreat... Stalemate and procrastination seem to be a general phenomenon of fuel cycle policy everywhere.

O'Neill (1998) identifies several factors as inhibiting the development of an international spent fuel management regime or regimes: widespread political and public opposition to siting of storage facilities (which would be heightened in a country faced with the prospect of becoming the world's nuclear dumping ground) and to transport radioactive substances within countries and across borders; differences in national interests and practices (for example, it is unlikely that most states with existing reprocessing capacity will give it up); sovereignty concerns; compliance, information gathering, and dissemination issues (states need assurances that if they comply, others will too, with appropriate verification provisions); and the long time horizons involved (for example, even interim storage sites would have to outlast not only political lives but the actual lifetimes of most political leaders).

O'Neill offers no easy answers to this stalemate but suggests an evolutionary strategy focussing initially on regional rather than global

arrangements, because states in a geographic region are more likely to share common norms (although, of course, animosities can also be intense at the regional level). And although both interim and permanent disposal face political opposition, there are probably fewer obstacles to the former.

Advanced nuclear generating options for the immediate future

In what follows, near-term advanced nuclear generating technology options are described, focussing on advanced LWR and fuel cycle technologies, and the pebble bed modular reactor. No attempt is made to be comprehensive; rather, the intent is to use these examples to illustrate what advanced technologies offer to address the challenges posed by current nuclear technologies.

Advanced light water reactors

Can LWR technology improvements help in addressing the challenges facing current technologies? Simpler plant designs and shorter plant construction periods would help bring down costs. Improved safety designs could help restore public confidence in nuclear power. And more proliferation-resistant designs would reduce proliferation and diversion risks.

Evolutionary advanced light water reactors. In recent years the main nuclear reactor vendors have developed modified LWRs that offer both improved safety and lower cost than LWRs now in use (NRC, 1992; CISAC, 1995; Kupitz and Cleveland, 1999).⁸² These modified LWRs build on more than 40 years of experience with LWR technology to provide technological improvements in standardised designs, for which there can be a high degree of confidence that performance and cost targets will be met. All of the modified LWRs use active but simplified safety systems, and some have some passive safety features.

One reactor in this category is the Westinghouse AP600, a 600-megawatt-electric pressurised water reactor (PWR). The design is simpler than existing PWRs; and it is modular, with about half the capacity of most existing PWRs—which allows some components to be factory-built and assembled faster on-site at lower cost than for plants that are entirely field-constructed. The AP600 is expected to be safer than existing PWRs, able to be constructed in 3 years, and cost about 15 percent less than existing PWRs of the same capacity (NPDP, 1998). In late 1999 the AP600 received design certification from the U.S. Nuclear Regulation Commission.

Also in this category are the ABB/Combustion Engineering System 80+ and the GE Advanced Boiling Water Reactor (ABWR); both received design certification from the U.S. Nuclear Regulatory Commission in 1997. The System 80+ is a large (1,350-megawatt-electric) unit, for which the estimated core damage frequency is 2.7 times 10^{-6} , two orders of magnitude lower than for its predecessor. The ABWR has as a design objective a core damage frequency of less than 10^{-6} and a target capital cost that is 20 percent less than for BWRs previously built in Japan (NPDP, 1998). Two ABWRs are now operating in Japan. Two more are under construction in Japan and

There seem to be reasonably good prospects for making reactors demonstrably safe while simultaneously reducing costs.

also in Taiwan (China).

In Europe a Framatome-Siemens joint venture and a group of 'nuclear' German utilities have developed the European pressurised water reactor (EPR), a 1,750-megawatt-electric system designed to specifications endorsed by utilities in Europe—with hoped-for economies of scale at this large unit size. The EPR is being offered on the international market.

Shifting light water reactors to a denatured uranium-thorium fuel cycle. If the advanced LWRs described above were operated on low-enriched uranium in once-through fuel cycles, they would be as proliferation and diversion resistant as existing LWRs, with fission products in spent fuel deterring plutonium removal by would-be proliferators and diverters. But because plutonium inventories build up quickly (200 kilograms a gigawatt-electric per year)—posing a significant proliferation hazard if the plutonium is separated by reprocessing, and conceivably making spent fuel at reactors or in off-site storage potential targets for proliferation and diversion—attention has been given recently to LWRs operated on a denatured uranium-thorium once-through fuel cycle that is more proliferation-diversion-resistant even than current LWRs operated on a once-through fuel cycle (Gasparin, Reichert, and Radkowsky, 1997; Herring and MacDonald, 1998).

Although it would not differ markedly from current LWR technology with regard to capital cost and safety, the LWR operated on a denatured uranium-thorium once-through fuel cycle would produce less transuranic wastes than current LWRs. Most important, it would have proliferation and diversion resistant features relating to both plutonium and uranium. Only a fifth as much plutonium would be generated in spent fuel as in an LWR fuelled with low-enriched uranium. Moreover, the plutonium would contain a significant amount of Pu-238, which generates heat that makes weapon manufacture more difficult. In this cycle the U-233 is bred from thorium denatured by the U-238, at enrichment levels such that this uranium cannot be used to make weapons without further enrichment; moreover, the uranium contains gamma-emitting daughters of U-232, which makes weapon manufacture more difficult.⁸³

The technology is not diversion-proof. Reliable nuclear weapons could be made by many nations from both plutonium and uranium that could be recovered from spent fuel by relatively straightforward chemical means.⁸⁴ In the hands of terrorists or an unsophisticated country, the recovered plutonium could be used to make weapons with yields of 1 or 2 kilotons. These reservations notwithstanding, this system would be more proliferation-resistant than a conventional LWR operated on slightly enriched uranium, because incentives for recovering weapons-usable material from spent fuel would be less.

Yet discussion of the specifics of this particular technology shows that setting goals for proliferation and diversion resistance will not be easily accomplished. This is because trade-offs must be taken into account in considering the weapons potential of the plutonium and uranium materials involved.

The pebble bed modular reactor.

For decades, a different approach to nuclear fission based on moderating the reactor with graphite and cooling it with helium (rather than using water for both purposes in LWRs) has been under development in several countries. These high-temperature gas-cooled reactors (HTGRs) typically involve large numbers of tiny uranium fuel pellets encased in layers of carbon, silica, or both (designed to contain the fission products from the reaction). These pellets are generally pressed into larger fuel elements, which are either encased in solid graphite blocks or circulate through the reactor core in a so-called pebble bed system.⁸⁵

Modern HTGRs are designed to be passively safe, offering the potential to avoid many of the complex, expensive safety systems used in LWRs. Moreover, HTGR concepts are being explored that would have lifetime cores—that is, they would be installed, switched on, and the operators would not have to do anything about fuelling or de-fuelling for the life of the reactor. In combination, it is hoped that such features could lead to lower costs and improved safety. In what follows, design and performance issues for the pebble bed modular reactor (PBMR) are discussed to illustrate the possibilities that might be offered by HTGR technology.

The key to enhanced safety for the PBMR is a design that ensures that the highest temperature in the reactor core—under any conceivable operating or accident condition—never exceeds the 1,600 degrees Celsius operating limit of the fuel. This requirement limits the thermal output for a single module to 250 megawatts-thermal and the electrical output to 100 megawatts-electric—a factor of 10 smaller than for a typical LWR. The viability of the technology depends, among other things, on being routinely able to produce high-quality fuel particles and pebbles. There have been problems in the past in particle design and manufacturing, leading to release of radioactivity from the particles (NRC, 1992). In addition, the direct helium gas turbine cycle required with the PBMR is undemonstrated for a nuclear plant and requires substantial engineering (CISAC, 1995).

The spent fuel of the PBMR would be high-burn-up material in many tiny spheres, making it a comparatively unattractive source from which to recover weapons-usable material. Moreover, the PBMR and other HTGR variants could be operated on a denatured uranium-thorium once-through fuel cycle that would have the same proliferation and diversion resistance features as an LWR operated on this fuel cycle (Feiveson, von Hippel, and Williams, 1979).

The PBMR's extraordinarily low power density⁸⁶ (a key safety feature) and modest scale will tend to drive up its specific cost (dollars per kilowatt-electric). But developers hope that these diseconomies will be offset at least partially by cost-saving opportunities—including design simplicity and system modularity that facilitate standardisation and realisation of mass production economies with a high fraction of the construction taking place in factories. Use of a closed-cycle helium gas turbine instead of a steam turbine for energy conversion assists in this objective, because this turbine's specific cost is lower

and less scale-sensitive than the LWR's steam turbine.

Eskom, the South African utility attempting to develop the technology (Nicholls, 1998), is targeting a capital cost of \$1,000 per kilowatt-electric under mass production conditions for a power plant made up of a block of 10 100 MW_e modules. This is far less than the costs of \$1,700–3,100 per kilowatt-electric that characterise today's LWRs (Paffenbarger and Bertel, 1998). Despite the good prospects for cost cutting as a result of the PBMR's attractive features (such as passive safety, modularity, and the relative scale insensitivity of the helium turbine's capital cost), this is an aggressive cost target, considering the high capital cost for the reactor itself that is inherent in its low power density—which requires, for example, very large and costly reactor vessels that can withstand high operating pressures. An MIT group investigating the PBMR estimates a capital cost about twice that estimated by Eskom (NPPDP, 1998). Earlier independent estimates of the capital cost of other HTGR systems, such as the General Atomics system developed in the United States, tended to be consistently higher than the costs of LWRs, because of the low power density of the HTGR concept (NRC, 1992).

The technology is at too early a developmental stage to ascertain which of these estimates is closer to what can be expected in a commercial product. If the MIT estimate turns out to be close to the mark, the cost of electricity from this plant (table 8.15) would be about the same as for an coal integrated gasifier–solid oxide fuel cell–steam turbine power plant with CO₂ separation and sequestration (see table 8.9). If the cost turns out to be closer to the Eskom estimate, the direct economic balance would tip in favour of the PBMR. In such circumstances, other factors such as public attitudes towards waste disposal could be important determinants in the race between nuclear and fossil technologies to near-zero emissions.

In contrast to the approach being taken for advanced LWR development—an activity that is well advanced; involves making only incremental, evolutionary changes relative to existing LWRs; and can build on a well-established industrial base—industrial activity relating to HTGRs is embryonic. No HTGR has yet been economically competitive. Nevertheless, the concept illustrates reasonable prospects for achieving at least the goal of demonstrable safety.

Nuclear energy for the long term

Uranium resource constraints might someday become important determinants of nuclear technology development. For the global high-nuclear-growth scenario discussed above, cumulative uranium requirements to 2050 with current technology are 3 million tonnes—less than reasonably assured resources recoverable at less than \$130 a kilogram, so that resource constraints are not important in this period. But cumulative uranium requirements to 2100 for this scenario are close to the estimated 20 million tonnes of conventional uranium resources (including 12 million of speculative resources; chapter 5).

Thus, sometime after 2050, technology that can address the resource constraint challenge might have to become available under high-nuclear-growth conditions. Can advanced technologies address

this potential constraint while simultaneously satisfying cost, safety, and proliferation and diversion concerns? In light of prospective long research and development gestation times and the need to make rational near-term research and development resource allocation decisions regarding post-2050 deployment options, it is important for this report to address this question. Five options are considered: conventional plutonium fast breeder reactors; alternative breeder concepts; extracting uranium from seawater; large-scale, internationalised nuclear energy parks; and thermonuclear fusion.

Conventional plutonium fast breeder reactors

Until the mid-1970s, it was thought that uranium was scarce. Therefore, it was expected that the LWR would be a stop-gap technology to provide start-up fuel for the fast breeder reactor (FBR), which by 1990 would overtake the LWR as the technology of choice for new plants (Lidsky and Miller, 1998).⁸⁷

The LWR makes use of only 0.5 percent of the fission energy stored in natural uranium—primarily that in the fissile (chain-reacting) isotope U-235, which accounts for only 0.7 percent of natural uranium. The FBR would alleviate this constraint by transmuting a large fraction of the abundant fertile isotope U-238 through neutron capture into fissile isotopes of plutonium—making it possible to extract 50–100 times as much energy from a kilogram of uranium as the LWR. Among FBR options, particular attention was given to the liquid-metal (sodium) cooled fast breeder reactor (LMFBR), which offered the potential of being an effective fuel factory that could produce excess plutonium—adequate not only to sustain itself but also to serve as seed stock for a rapidly growing fleet of similar reactors.

The LWR-FBR vision has not materialised, and the prospects that

TABLE 8.15. TWO ESTIMATES OF THE ELECTRICITY GENERATION COST FOR THE PEBBLE BED MODULAR REACTOR (DOLLARS PER THOUSAND KILOWATT-HOURS)

Cost component	Estimate based on Eskom parameters ^a	Estimate based on MIT parameters ^b
Capital ^c	16.4	34.2
Operation and maintenance ^d	4.1	4.1+0.6 ^e
Fuel	3.8	3.8
Total	24.3	42.7

Note: Estimates are for a 1,000 megawatt-electric plant made up of 10 100-megawatt-electric modules.

a. Data are from Nicholls, 1998. b. Data are from Kadak, 1999. c. For an annual capital charge rate of 11.5 percent and an 80 percent capacity factor. The unit capital cost estimated by Eskom and MIT analysts are \$1,000 and \$2,090 per kilowatt-electric, respectively. d. The staffing requirement for the plant is estimated to be 80 persons by Eskom (Nicholls, 1998) and 150 persons by MIT analysts (Andy Kadak, private communication, 8 September 1999). e. The \$0.6 per thousand kilowatt-hours component of the cost is for decommissioning (Kadak, 1999).

it ever will are not bright. Although a few countries have FBR development programmes (China, France, India, Japan, Russia), these programmes are in virtual stasis. Most countries have abandoned once-ambitious programmes as a result of unpromising economics and a much brighter global outlook for uranium supplies (chapter 5) than when FBR programmes were originally put in place.⁸⁸ By the late 1970s it had become clear that FBR unit capital costs (dollars per kilowatt) would be much higher than for LWRs and that costs for fabricating MOX LWR fuel and FBR fuel would be far higher than previously projected. Life-cycle cost comparisons made at that time showed that the FBR could not compete with the LWR at then-projected uranium prices (Feiveson, von Hippel, and Williams, 1979). And now, with expectations that relatively low-cost uranium resources are far more abundant than was thought 20 years ago, it appears that the need for an FBR or alternative uranium-saving technology will not materialise before 2050, and possibly long after that (STATS, 1996).

Alternative breeder concepts

If uranium scarcity concerns should one day force a shift to breeder reactors, it would be desirable to have technologies that are simultaneously demonstrably safe and cost competitive and much more proliferation and diversion resistant than conventional liquid-sodium-cooled plutonium fast breeder reactors, which involve reprocessing spent fuel and recycling recovered plutonium in fresh reactor fuel.⁸⁹

One set of such technologies is metal-cooled fast reactors, for which plutonium is never separated from fission products. One variant of the concept under investigation is a metal-cooled fast reactor using lead or a lead-bismuth eutectic instead of sodium as the liquid metal coolant (Filin and others, 1999; Hill and others, 1999; Lopatkin and Orlov, 1999; Orlov and others, 1999; Zrodnikov and others, 1999), building on Russian work carried out on lead-bismuth-cooled reactors for submarine applications.⁹⁰ Spent fuel reprocessing technology for these reactors would be designed to extract most fission products for waste disposal but leave 1–10 percent of the fission products plus plutonium and most transuranics in the reprocessed fuel that is returned to the reactor. The radiation hazard from residual fission products and transuranics would deter would-be proliferators and diverters.

Some natural or U-235-depleted uranium would be added to reprocessed fuel as source material to generate more plutonium in the reactor; the reactor would be designed to produce from uranium as much plutonium as it consumes.⁹¹ A high level of burn-up of transuranics and long-lived fission products in the spent fuel could be achieved with repeated recycling and appropriate reprocessing technology—without the need for separate burners for transuranics and long-lived fission-products. Moreover, reprocessing plants might be co-sited with reactors, to eliminate proliferation and diversion risks associated with the transport of spent and reprocessed fuel. A modest-scale (100-megawatt-electric) version with a lifetime (15-year) sealed core has been proposed for developing country applications (Hill and others, 1999).⁹²

Although this liquid metal reactor technology would deal effectively with the uranium supply constraint challenge and be more proliferation and diversion resistant than conventional plutonium breeder reactors, the reactors would have very large plutonium inventories—for example, 8–9 tonnes for a large 1,200-megawatt-electric design (Filin and others, 1999) and 2.5 tonnes for a small 100-megawatt-electric unit with a lifetime reactor core (Hill and others, 1999).⁹³ Although the system would be designed so that plutonium would never be fully separated from spent fuel, such systems would provide their operators with extensive knowledge of, experience with, and facilities for chemical processing of intensely radioactive spent fuel, which could provide the basis for moving quickly to separating plutonium for a weapons programme should a decision be made to do so.

Moreover, for safeguards, either new measurement technologies would have to be developed to allow accurate material accounting for the intensely radioactive material involved in these fuel cycles, or almost complete reliance would have to be placed on containment and surveillance measures rather than material accounting. Hence, although such systems would certainly have higher inherent proliferation resistance than traditional reprocessing and recycling approaches involving fully separated, weapons-usable plutonium, the overall proliferation risks that might result from widespread deployment of these technologies across the globe are likely to be the focus of considerable debate in the technical community, should large-scale deployment ever seem a realistic possibility.⁹⁴

Other alternative breeder concepts include molten salt thermal breeder reactors that would integrate continuous reprocessing for removal of fission products with reactor operations (Tinturier, Estève, and Mouney, 1999) and various particle-accelerator-based reactor concepts. Each seems to have one or more attractive features relative to conventional breeder reactor concepts, but all are technologies whose relative merits regarding cost, safety, proliferation-diversion risk, and waste disposal are the subject of intense debate in the technical community (NRC, 1992; CISAC, 1995).

Extracting uranium from seawater

If low-cost uranium resources are much more abundant than indicated by conventional uranium resource estimates (chapter 5), even high nuclear growth to 2100 and beyond could be realised with proliferation and diversion resistant once-through fuel cycles. The recovery of uranium from seawater is one promising option for extending uranium resources; preliminary estimates of recovery costs are \$100–300 per kilogram (chapter 5). Although the high estimated recovery cost is more than 10 times the current uranium price, it would contribute just \$0.004 per kilowatt-hour to the cost of electricity for an HTGR operated on a once-through denatured uranium-thorium fuel cycle⁹⁵—equivalent to the fuel cost for an oil-fired power plant burning oil priced at \$2.50 a barrel!

Recovery of 15 percent of the uranium in seawater could support the year 2100 nuclear capacity level (6,500 gigawatts-electric) in the high-growth scenario (discussed above) for 1,000 years using such once-through reactor-fuel-cycle technologies. The key unresolved question is whether production of uranium from seawater could be

The essence of the potential nuclear weapons link to fission power is that this technology provides the possibility of obtaining access to nuclear explosive materials.

carried out at acceptable cost at scales large enough to support a significant fraction of the world's nuclear capacity.

Large-scale, internationalised nuclear energy parks

If development of advanced proliferation- and diversion-resistant nuclear energy systems proves to be an elusive goal and the world opts for large-scale use of reprocessing and recycling technologies with substantial proliferation and diversion vulnerabilities, it might become necessary to cluster all the sensitive facilities—enrichment plants, reactors, reprocessing plants, fuel fabrication plants—in large, heavily guarded nuclear parks under international control to reduce the proliferation and diversion risks of nuclear fission. Electricity produced in such parks could be made available even to remote users through direct-current transmission lines. In addition, with reactors operated at suitably high temperatures (for example, high-temperature, gas-cooled reactors), hydrogen might also be produced as an energy carrier for world-wide energy commerce—initially perhaps by steam-reforming natural gas and ultimately with advanced thermal cycles that would use nuclear heat to extract hydrogen from water (Marchetti, 1976; Miyamoto and others, 1999; Scott and Hafele, 1990; Wade and Hill, 1999).

There is no doubt that this is technically feasible and would reduce proliferation and diversion dangers substantially. Much more questionable, however, is whether it is politically realistic to expect all the world's countries to place major components of their electricity supplies under international control—and to agree on the administrative arrangements for doing so.

Thermonuclear fusion

Another nuclear energy option for the very long term is thermonuclear fusion, based on exploiting the energy recovered in fusing light elements (for example, deuterium and tritium) rather than fissioning uranium or plutonium. The resources upon which fusion would depend—lithium and deuterium in seawater—are virtually inexhaustible.

How fusion compares with fission with regard to reactor safety, radioactive waste management, and proliferation and diversion risks depends on how the technology is developed. But relative to today's LWRs, it offers considerable promise, for three reasons (PCAST Fusion Review Panel, 1995). First, with regard to safety, population exposures to radiation from worst-case accidents are 100 times smaller than those from worst-case fission accidents. Second, with respect to radioactive waste hazards, those from fusion (on the basis of the most meaningful of indices combining volume, radiotoxicity, and longevity) can be expected to be at least 100 times and perhaps 10,000 or more times smaller than those from fission. Third, with regard to nuclear weaponry, electricity supply systems based on fusion would be less likely than fission systems to contribute to nuclear weapons capabilities acquisition by sub-national groups and, if designed appropriately, could be easier to safeguard against clandestine fissile material production by governments.

Despite these advantages, it is still unclear whether fusion will eventually become a commercial energy technology. Even if technical goals can be realised, fusion is not expected to become an option for commercial energy applications before 2050 (PCAST Fusion Review Panel, 1995).

The outlook for addressing the challenges

Can the challenges related to nuclear power—cost, safety, proliferation and diversion, and waste management—all be adequately addressed with advanced technologies to make it widely acceptable? This question cannot be fully answered at this time—in part because consensus has not been reached on goals for technological innovation, and in part because the answer does not depend only on technical considerations.

Clarification of goals is needed to facilitate the development of a focussed nuclear energy innovation effort. The market, ideally with external costs internalised, will determine the competitiveness of future nuclear technologies, so that cost goals for the technology will have to be adjusted over time to respond to the changing competition. Although this uncertainty is common to all technologies, the intrinsic high investment cost required to bring new nuclear technologies to market makes this a continuing difficult challenge for nuclear power. Among externality concerns, consensus might converge on a goal of demonstrable safety (Lidsky, 1991).

However, goals relating to proliferation and diversion resistance and waste management require considerable clarification. There is a strong technical case that LWRs operated on once-through fuel cycles are more proliferation and diversion resistant than today's reprocess-recycle technologies, but beyond that there is little agreement in the technical community as to the relative merits of alternative advanced concepts. For waste management, goals need to be better defined, not only to include various non-technical considerations but also to ensure that proliferation and diversion resistance goals are not compromised.

There seem to be reasonably good prospects for making reactors demonstrably safe while simultaneously also reducing cost—although this must be demonstrated, through appropriate research, development, and dissemination. This leaves proliferation and diversion and waste management—issues that also involve cost considerations. How much more proliferation and diversion resistant advanced nuclear technologies can be made relative to LWRs operated on once-through fuel cycles is unclear—as is the potential for maintaining even this degree of resistance in the future, when uranium might be much scarcer than it is today. But at least for the immediately future, there are no economic obstacles to making reactors at least as resistant to proliferation and diversion as LWRs operated on once-through fuel cycles.

A promising option for sustaining the proliferation and diversion

Although coping with the radioactive waste problem seems manageable from a technical perspective, a technical fix by itself is not a solution.

resistance of reactors operated on once-through fuel cycles seems to be extraction of uranium from seawater. Because the technology probably will not be needed at least until sometime after 2050, there is no urgency to develop the technology.

However, a critical near-term need is assessment of the feasibility of the concept at large scale to provide a more informed basis for prioritising research and development on alternative nuclear technologies for the long term.

Waste management is probably a technically soluble problem, but it is unclear whether promising technical fixes can be made broadly acceptable to the public. S&T technologies for burning transuranics and long-lived fission products will probably get considerable research and development support as an option for addressing the waste disposal challenge—in large part because many people have little confidence in human capabilities to adequately manage waste risks for the long periods required (O'Neill, 1998)—even though S&T technologies are probably not necessary to adequately protect the public in the very long term. In a world where overall research and development investment funds are limited, such investments could limit funds available for other needed nuclear research and development activities.

In summary, for nuclear energy to qualify as a sustainable energy option, concerns regarding safety, waste disposal, and proliferation and diversion must be addressed in ways that enable nuclear energy to compete on an economic basis. Effectively addressing these concerns to enable a large expansion of nuclear power probably requires advanced technologies, as well as improved institutional risk management strategies.

Although it is possible to envision sets of nuclear technologies and management strategies that might fulfil the requirements for sustainability, decisions on future nuclear power will be made largely at the political level rather than on narrow technical and economic grounds. Gaining broad public support for nuclear power is not simply a matter of better educating the public on the issues, which is what many in the nuclear industry believe is needed most. The industry should also seek to better understand public concerns.⁹⁶ The industry must recognise that a stable political consensus on nuclear goals and strategies is needed to bring about a nuclear-intensive energy future. The industry should also consider opening up the nuclear decision-making process to diverse interest groups, so that a well-informed public could ensure that its concerns are addressed every step of the way (Bunn, 1999).

During the next 20 years there might be enough nuclear plant orders (mainly in Asia) and business opportunities associated with maintaining existing plants to keep the nuclear industry from collapsing. But taking into account expected plant retirements, this period will probably be characterised by little if any net nuclear power expansion world-wide. The industry might consider this de facto moratorium on net expansion as a window of opportunity for confidence-building, through which it could seek to convince the

public and investors that concerns about cost, safety, proliferation and diversion, and waste disposal can be dealt with effectively.

The number one priority on the confidence-building agenda is to reach a broad consensus on waste disposal policy. To get this consensus requires that industry engage effectively all stakeholder groups, including those ideologically opposed to nuclear power. Whether the needed deal-making is feasible or not is unknowable at this time, but not implausible. For example, as a strategy to deal with its strongest critics, industry leaders might consider becoming vocal supporters of public-sector-supported renewable energy and energy efficiency programmes in exchange for broad support for sensible nuclear waste management strategies and policies—in effect, giving the renewable and energy efficiency communities the opportunity (during the moratorium) to show whether they can deliver on what they hope for.⁹⁷

If the energy innovation effort in the near term emphasises improved energy efficiency, renewables, and decarbonised fossil energy strategies,⁹⁸ the world community should know by 2020 or before much better than now if nuclear power will be needed on a large scale to meet sustainable energy goals. With broad support for a sensible waste management strategy, the nuclear industry would be far better positioned to take off again at that time than if it were to continue dealing with its critics in a more confrontational manner.

In parallel with such confidence-building, the industry might consider strategies to prioritise the nuclear energy innovation effort. The first steps might include exploratory research and development (which is quite inexpensive relative to building large-scale demonstration projects) aimed at better clarifying the options.⁹⁹ These steps could be followed by efforts to reach consensus within the technical community regarding priorities, so that the industry would be well prepared to move ahead if the world community eventually decides that large-scale nuclear power is needed to meet sustainable energy goals. ■

Notes

1. Major reviewers for this chapter were Harry Audus (United Kingdom), Tim Brennand (United Kingdom), Ramon Espino (United States), Richard Garwin (United States), Chris Hendriks (Netherlands), Olav Kaarstad (Norway), Larry Lidsky (United States), Marvin Miller (United States), Larry Papay (United States), Jefferson Tester (United States), and Maarten van der Burgt (Netherlands).

2. Because methane is a powerful greenhouse gas (chapter 3), getting climate change benefits from shifting to natural gas requires minimising gas leakage from the entire gas system.

3. The Convention on Climate Change seeks to “achieve stabilisation of the greenhouse gas concentration in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate system. Such a level should be achieved within a time frame sufficient to allow economic systems to adapt naturally to climate change, to ensure that food production is not threatened, and to enable economic development to proceed in a sustainable manner” (UNFCCC, 1992).

4. For example, the World Bank (World Bank, 1997) has estimated that in 1995 air pollution damages in China cost \$48 billion, or 7 percent of GDP; see chapter 3.
5. In a study carried out under the auspices of the European Commission's ExternE Programme, Krewitt and others (1999) estimated that for the European Union (EU-15) the total cost of environmental damages arising from air pollutant emissions of fossil fuel power plants in 1990 was \$70 billion, or more than \$0.06 per kilowatt-hour of electricity generated; 97 percent of this cost is related to health—mostly fine-particle air pollution.
6. Uncontrolled emissions increase roughly in proportion to oil plus coal consumption, which in turn grows roughly in proportion to GDP. Assuming, as economists often do, that the willingness to pay to avoid health damages from air pollution increases as (GDP/P) , it follows that the cost of health damages from uncontrolled emissions increases roughly as $P \cdot (GDP/P)^2$, where P = population.
7. The cost estimates presented in tables 8.1 and 8.2, like the estimates in Krewitt and others (1999), were developed under the ExternE Programme of the European Commission.
8. This gap exists for a variety of reasons—for example, regulated emission levels are for well-maintained cars, and regulations tend to be for driving cycles that often do not adequately reflect the way people actually drive cars (Ross, Goodwin, and Watkins, 1995).
9. To illustrate the challenge of addressing air quality goals as economies evolve, consider a simple model of a hypothetical average developing country that grows from its 1990 state, in which per capita GDP $(GDP/P) = \$2,300$ (1990 dollars, purchasing power parity basis—the average for all developing countries in 1990) and there are no air pollutant emission controls in place, to a future state where per capita GDP is 7.2 times higher $(GDP/P = \$16,400)$, the average for countries belonging to the Organisation for Economic Co-operation and Development, or OECD, in 1990—a level that could be realised in 100 years with a sustained 2 percent per year GDP/P growth rate). Suppose also that in this period per capita consumption of coal plus oil also increases 7.3 times, from the actual average level in 1990 for developing countries to the 1990 level for OECD countries, and that without controls pollutant emissions increase in proportion to coal plus oil consumption levels. Without pollution controls and taking into account an expected doubling of population in this period, health damage costs would increase about 100 times $(2 \times 7.2 \times 7.3)$; assuming, as most economists do, that the willingness to pay to avoid pollution damages increases in proportion to per capita GDP. Thus end-of-pipe controls that reduce emissions by 99 percent would be required to keep damage costs in dollar terms to a level no greater than in 1990.
10. For example, the U.S. Department of Energy's Vision 21 Program (Clean Energy Plants for the 21st Century) seeks—in addition to achieving near-zero pollution emissions with advanced technology—reduced CO_2 emissions through both efficiency improvements and development of the capability to reduce CO_2 emissions to zero or near zero by means of CO_2 capture and sequestration. A complementary new DOE programme is carbon sequestration—a research and development effort aimed at developing carbon sequestration technologies to the point of deployment, so that these sequestration technologies will be ready to be deployed (if and when needed).
11. Efficiencies have been rising continually in conjunction with increasing turbine inlet temperatures, which have been rising at an average rate of 13 degrees Celsius a year for the past 30 years (Chiesa and others, 1993), as a result of more heat-resistant materials being used for turbine blades and improved turbine blade cooling technologies.
12. On a lower heating value (LHV) basis, the efficiencies of the Frame 7F and Frame 7H are 56 and 60 percent, respectively.
13. Some regulations require controlling NO_x emissions to less than 10 parts per million, dry volume basis (at 15 percent O_2)—relative to typical uncontrolled emissions for natural-gas-fired systems of 125 parts per million.
14. In a typical gas turbine, two-thirds of the output of the turbine is needed to drive the compressor.
15. Spray intercooling has been applied to an existing gas turbine (without major modification) in a commercial product (McNeely, 1998). But this unit involves only 1–3 percent of the maximum feasible water injection rate.
16. The electricity generating potential through combined heat and power in a particular industry is the heat load times the characteristic output ratio of electricity to heat for the cogenerating technology.
17. These large syngas projects that involve electricity as a product or coproduct are part of a recent global inventory of syngas projected compiled by Simbeck and Johnson (1999) that involves 161 real and planned commercial-scale projects with a combined syngas production capacity of 60,880 megawatts-thermal. Many of these are polygeneration projects that involve the coproduction of various combinations of products—for example, electricity, steam for process, chemicals, town gas; and many of the projects are in the petroleum refining and chemical industries. About 44 percent of the productive capacity is based on coal; much of the rest is based on the use of low-cost petroleum refinery residues.
18. As an IGCC-based power industry grows, the benefit of by-product sulphur sales per kilowatt-hour will eventually decline when the sulphur supplies exceed demand, so that sulphur prices will fall.
19. For the cogeneration systems described in tables 8.7 and 8.8, condensing and extraction turbines rather than back-pressure turbines are needed; otherwise the ratio of electricity to heat production would be less than 1 to 1. (In condensing and extraction systems, some of the steam is bled from the turbine at the pressure appropriate for the process, and the rest of the steam is used to produce more power and then condensed; for the steam that is condensed, there is no cogeneration fuel-saving benefit.) The fraction of the steam that must be condensed is much greater in the steam turbine case than in the IGCC case, because of the much lower electricity-heat output ratios for steam turbines relative to combined cycles (see figure 8.1).
20. At present, gases exiting the gasifier at temperatures of 1,000 degrees Celsius or more are cooled to about 100 degrees Celsius to facilitate cleaning the gas of particulates and sulphur and nitrogen compounds. Then the cleaned gas is heated up to the turbine inlet temperature of 1,300 degrees Celsius or more.
21. Most of the rest will be used for standby service.
22. Because the temperature of the turbine exhaust is higher than that of the air exiting the compressor, the turbine exhaust heat is often recovered to preheat the air exiting the compressor before it is delivered to the combustor, so that moderate efficiencies are achievable despite the low pressure ratio.
23. Less than 0.24 grams per kilowatt-hour (9 parts per million by volume at 15 percent O_2) for the 28-kilowatt-electric Capstone Model 330 using a non-catalytic staged combustion system.
24. Ballard is a joint venture involving Ballard Power Systems, General Public Utilities International, and GEC Alsthom. Plug Power is a joint venture involving Mechanical Technologies, Inc., Detroit Edison, and General Electric.
25. An operating temperature in the range 700–800 degrees Celsius enables an efficiency increase of about 10 percent without compromising fuel flexibility and the process advantages offered by SOFCs operated at 1,000 degrees Celsius. A reduced operating temperature also leads to greater choice of electrode materials and reductions in system cost and complexity (Goldstein, 1992).
26. Oxygen would be needed for coal gasification, in any case.
27. Shell intends to use the technology in conjunction with its own oil and gas operations—including use of the separated CO_2 for enhanced oil recovery (SIEP, 1998).
28. To be effective in sequestering CO_2 , aquifers need not be leak free. Lindeberg (1997) modelled CO_2 sequestration for injection during a 25-year period into aquifers for which there is an open boundary or fracture 8,000 metres from the injection well and showed that, if such aquifers

have high permeability, some of the injected CO₂ would eventually escape. Assuming all CO₂ associated with future fossil fuel consumption (7,000 GtC) as projected in the IPCC's IS92a scenario (IPCC, 1995) is injected into such aquifers, Lindeberg estimated for the worst (leakiest) case that a fifth of the injected CO₂ would eventually leak out but would do so slowly over many centuries at climatically inconsequential rates—with leakage peaking in 3100 at 2 GtC per year; in contrast, if the same amount of CO₂ were released to the atmosphere during fossil fuel combustion, emissions would increase until they peak at 30 GtC a year in about 2150 and subsequently decline as fossil fuel resources are depleted.

29. All cases include costs to pressurise CO₂ to 135 bar plus a CO₂ disposal cost of \$18 per tonne of carbon (equivalent to \$5 per tonne of CO₂).

30. The calculation presented is an updated calculation for this decarbonisation of fuel gas strategy originally advanced by Blok, Hendriks, and Turkenburg (1989) and van der Burgt, Cantle, and Boutkan (1992); also see Chiesa and Consonni (1998).

31. This is for disposal near the CO₂ separation site or for disposal with some credit for enhanced resource recovery. If the separated CO₂ had to be transported 500 kilometres to a remote aquifer for disposal, with no credit for enhanced resource recovery, the avoided cost would increase about another \$10 per tonne of carbon (Williams, 1999b).

32. The system described in table 8.10 (based on Simbeck, 1999c) involves an autothermal reformer that uses steam and O₂ for reforming natural gas. Audus, Kaarstad, and Singer (1999) describe a system that instead uses steam and air for reforming, thereby avoiding the cost for air separation; their estimate of the CO₂ recovery cost penalty is less than two-thirds of the estimate in table 8.10. Simbeck (1999c) also estimates costs for autothermal reforming with steam and air but finds the cost to be higher than for reforming with steam and O₂, because savings from avoiding the cost of an air separation unit are more than offset by higher costs for downstream components that arise because the fuel gas is diluted with nitrogen from air.

33. For the advanced technology (2012) cases considered by Herzog (1999a), the lower heating value (LHV) efficiencies with CO₂ recovery and disposal are 55.6 percent for the NGCC case and 42.4 percent for the coal IGCC case, compared to 50.8 percent and 37.2 percent for the corresponding cases presented in table 8.10. The corresponding busbar costs in the Herzog analysis with 2020 U.S. fuel prices are \$0.045 per kilowatt-hour for the NGCC case and \$0.044 per kilowatt-hour for the coal IGCC case. (To put the Herzog analysis on the same basis as the present analysis, Herzog's annual capital charge rate was changed from 15 to 11.5 percent, the capacity factor was increased from 75 to 80 percent, and a CO₂ transport-and-disposal cost—not taken into account by Herzog—of \$5 per tonne of CO₂ was included.)

34. A litre of water contaminated with MeOH would contain a fatal dose if it were 2–7 percent MeOH by weight.

35. The cetane number is a measure of a fuel's ability to auto-ignite. A high cetane number is desirable for candidate fuels for compression-ignition engines because it shortens ignition delay, lowering premixed burning and resultant NO_x emissions and noise. High octane fuels have low cetane numbers, and fuels with high cetane numbers have low octane ratings.

36. This plant commenced operations in 1993 but was shut down in late 1997 by an explosion at the air separation plant (from the build-up of small particles taken in from the air—apparently as a result of the prolonged haze that had blanketed the entire South Asian region in late 1997). The plant is scheduled to reopen in 2000, after repairs are completed.

37. These increased emissions of especially small particles appear to arise as a result of controlling soot particle emissions—which dominate the mass of particulate emissions—using current technology. Removing soot particles thereby removes nucleating agents on which these tiny particles would otherwise condense or adsorb; these very small particles seem to come from ash in the lubricating oil (Abdul-Khalek and others, 1998).

38. The calculations presented in tables 8.11 and 8.12 are based on well-established cost estimates and cost-scaling exponents for each of

the many components of these systems. However, it is assumed in these calculations that each component (for example, the coal gasifier) can be built in a single train to the required capacity. The maximum sizes of single-train components that are commercially available today are less than the capacities associated with many of the components for the polygeneration systems presented in these tables. To the extent that multiple trains instead of single trains would have to be used for practical systems, the cost savings would be less than indicated in tables 8.11 and 8.12. But these tables illustrate the value of evolving towards systems based on large single-train systems and thus represent good targets for development.

39. Air Products and Eastman Chemicals tested liquid-phase MeOH production technology in a process development unit at LaPorte, Texas, which was designed to produce 6,900 litres per day and which operated for 7,400 hours. Following this, a commercial-scale plant (designed to produce 288,000 litres per day) went into operation in January 1997, at Kingport, Tennessee, under the U.S. Department of Energy's Clean Coal Technology Program, to demonstrate the technology during a period of 4 years of expected plant operation.

40. In China more than 20 Texaco gasifiers are operating, under construction, or on order for the production of chemical fertiliser, MeOH, town gas, or oxochemicals. In addition, 6 Shell gasifiers and at least 1 Lurgi gasifier are being used to produce ammonia (NH₃) from coal.

41. Water or steam injection would probably not be pursued for gas turbine and steam turbine combined cycles because these options would reduce efficiency. However, the technique would be appropriate for low-capital-cost systems that use steam or water injection for efficiency augmentation—such as intercooled steam-injected gas turbines (Williams and Larson, 1989) or, for water injection, Tophat® cycles (van Lier, 1998).

42. Consider H₂ manufacture from coal—a process that begins with O₂-blown coal gasification, which is also the first step in processing coal for IGCC plants. Just as pollutant emissions from coal IGCC plants are almost as low as from NGCC plants (see table 8.1), pollutant emissions from H₂ production plants are expected to be very low. Pollutant emissions per unit of coal consumed would tend to be lower than for IGCC plants, because gases exiting the gasifier must be cleaned to a higher degree to protect catalysts in downstream processing equipment from damage by contaminants such as sulphur. Catalyst protection requirements are often more stringent than regulatory requirements for air pollutant emissions.

43. For example, it is estimated that at a future (optimistic but plausible) photovoltaic electricity price of \$0.027 per kilowatt-hour, the cost of photovoltaic-derived H₂ would be \$17 per gigajoule (IPCC, 1996a). For comparison, the cost of making H₂ from natural gas and coal today, including the cost of storing the separated CO₂ underground, is \$6 per gigajoule for natural gas and \$11 per gigajoule for coal (Kaarstad and Audus, 1997). With advanced fossil-energy conversion technologies that are likely to be available by the time a photovoltaic electricity price of \$0.027 per kilowatt-hour is reached, fossil-energy-derived H₂ costs with CO₂ sequestration would be less (Williams, 1999b). (Even credit for the by-product O₂ generated in electrolytic processes would not help much; such a credit would amount to only about \$0.60 per gigajoule of electrolytic H₂ (\$20 per tonne of O₂) assuming an installed cost of \$21.60 per tonne of O₂ per day for an air liquefaction plant).

44. An H₂ fuel cell car would typically be three times more fuel-efficient than a conventional gasoline internal combustion engine car of comparable performance. This efficiency gain arises because, while the efficiency of an internal combustion engine declines with decreasing load (so that the efficiency of driving a car, averaged over all driving conditions, is a modest 15 percent), the efficiency of a fuel cell increases as the load decreases (so that the efficiency at average part-load conditions is a high 50 percent).

45. Some indicators of the level of industrial effort to develop fuel cell vehicles: by the end of 1999 the four largest Japanese manufacturers had spent \$546 million on fuel cell development. Honda has announced plans to spend up to \$500 million on fuel cell research and development during the next five years. DaimlerChrysler has spent \$300 million on fuel cells and expects that it will have spent \$1.4 billion by 2004, when it starts producing engines for fuel cell vehicles.

46. For F-T liquids production, syngas with an H₂ to CO ratio of 2 is needed. Because steam reforming instead gives a ratio of 3 (CH₄ + H₂O → CO + 3H₂), syngas is typically made through partial oxidation (CH₄ + 1/2 O₂ → CO + 2H₂), which gives the right ratio but requires an expensive air separation plant. When some CH₄ is instead used to produce H₂, the CO₂ by-product can be used for doing some CO₂ reforming (CH₄ + CO₂ → 2CO + 2H₂), along with steam reforming, to get the right overall ratio, thereby avoiding the need for an air separation plant.

47. The process of making H₂ from syngas (mainly CO and H₂) involves reacting the CO with steam (in water-gas shift reactors) to produce H₂ and CO₂. With current technology, this is followed by the use of capital- and energy-intensive equipment to separate the H₂ and CO₂.

48. As indicated in chapter 5, global methane clathrate hydrate occurrences have an energy content of 780,000 exajoules (table 5.7) and a carbon content of 12,000 GtC (table 5.8). If half of this resource could ultimately be recovered and burned along with 5,000 GtC of fossil energy reserves and resources (table 5.8), and if half the released CO₂ stayed in the atmosphere, the atmospheric CO₂ level would be eight times higher than at present.

49. The announced efficiency is on an LHV basis, and the design is for once-through processes using cold seawater under wintertime conditions for northern Europe and does not include energy penalties for pollution control. Correcting to the norm of 40 millibar (29 degrees Celsius) of the International Standards Organization for once-through cooling with steam condensation, accounting for fuel consumption requirements for air pollution control equipment that would lead to low levels of SO₂ and NO_x emissions, and converting to a higher heating value basis (the norm for this report), the efficiency would be about 43 percent (see entry in the first row of table 8.9).

50. Because cogeneration systems involving condensing heat transfer are less costly than those requiring steam cooling, reheat steam cycles (which deliver superheated steam) are typically not attractive (Kovacic, 1996).

51. The air separation plant contributes \$150 per kilowatt-electric to the capital cost of an IGCC plant and requires 12 percent of gross power output for operations (Simbeck, 1999a).

52. Advanced clean-up technologies being pursued operate at 500–600 degrees Celsius, well below the temperatures of gases exiting the gasifiers—so that the process is described as warm rather than hot.

53. The U.S. Department of Energy–supported demonstration project aimed at proving warm gas clean-up for IGCCs with air-blown gasification (a 100-megawatt-electric Pinon Pine IGCC Power Project in Nevada that was put into service in early 1997) had sustained operating runs of less than 13 hours as of June 1999 (Motter, 1999).

54. But air-blown gasifiers are well-suited for biomass IGCCs (Simbeck and Karp, 1995; Williams and Larson, 1993); low sulphur and nitrogen contents of typical feedstocks make biomass a good candidate for warm-gas cleanup. In addition, scale economies make air separation costly at the relatively small scales of most biomass power applications.

55. Heating up the extra mass of N₂ in combustion leads to lower peak flame temperatures for air-blown units.

56. In fluidised-bed combustion, fuel is burned in a bed of fuel and other materials that behaves like a fluid, as a result of a gas passing upwards through the bed fast enough to support fuel and other particles but not so fast as to transport particles out of the bed. Typically 2–3 percent of the weight of the bed material is coal.

57. Second-generation technology, which is entering the pilot and demonstration phases, will employ a coal pyrolyser to produce, from some of the coal input, fuel gas that is burned in a gas turbine combustor so as to increase the turbine inlet temperature of the gases delivered to the gas turbine.

58. Still another source of greenhouse gas emissions arises because all carbon in the limestone added to an AFBC unit for sulphur removal (limestone is typically added at two or more times the rate theoretically required for sulphur removal) is released as CO₂ at levels that could be

significant for high-sulphur coals. The problem is less for PFBC units, which can be designed to suppress CO₂ emissions from the quantities of limestone present in the bed at levels in excess of the theoretical amounts needed for sulphur removal. In both cases these extra CO₂ emissions are not significant in practice because the use of high-sulphur coals is not practical for fluidised-bed combustion units.

59. The need for H₂ arises from the H-C ratio of 2 for today's hydrocarbon fuels, relative to 0.8 for coal.

60. In 1996, more than 75 percent in France and Lithuania, and more than 50 percent in Belgium and Sweden.

61. The reference scenario of the Energy Information Administration (EIA) of the U.S. Department of Energy is that nuclear capacity will be 311 gigawatts-electric in 2020; the low-growth and high-growth EIA scenarios for 2020 project 179 and 442 gigawatts-electric of nuclear capacity, respectively (EIA, 1999a). The most recent forecast of the International Atomic Energy Agency (IAEA) is that nuclear capacity in 2020 will be 305–582 gigawatts-electric, with its share in total power generation falling by then to 10–14 percent (IAEA, 1999).

62. There is a considerable range in nuclear forecasts for individual countries. For Japan in 2010, the EIA (1999) projects 39.6–54.8 gigawatts-electric, with a reference value of 47.5 gigawatts-electric—relative to 43.9 in 1997. In contrast, the official (Ministry of Trade and Industry) projection for Japan in 2010 is 70 gigawatts-electric (Matsuoka and Hiranuma, 1998); others project 55–60 gigawatts-electric or less (Hard, 1997; Hagen, 1998). For China in 2010, the EIA (1999a) projects 8.7–11.5 gigawatts-electric, with a reference value of 11.5 gigawatts-electric—up from 2.2 in 1997. The Chinese National Nuclear Corporation has projected a total installed capacity of 20 gigawatts-electric by 2010; however, this might not be achieved, as a result of both overall excess electric generating capacity and the high costs of nuclear expansion.

63. The Rabl and Spadaro damage cost estimates include consideration of severe reactor accidents, for which they assumed a reactor core melt probability of 10⁻⁵ per year with a release of 1 percent of the radioactivity in the core in an accident—corresponding to the reference accident scenario used by French national safety authorities. According to the authors, the calculations assume “a mature and stable political system, with strict verification of compliance with all regulations.”

64. This scenario involves net new nuclear generating capacity being added at an average rate of 62 gigawatts-electric per year during the next 100 years, and, if nuclear plants last 40 years, a corresponding average rate of nuclear plant construction (including replacement capacity) of 115 gigawatts-electric per year. For comparison, the nuclear capacity in the most nuclear-intensive IASA-WEC scenario (A3) is 6,000 gigawatts-electric in 2100 (chapter 9).

65. Assuming 50 percent efficient coal plants and 60 percent efficient natural gas plants.

66. Cumulative CO₂ emissions for the IPCC's IS92a scenario are 1,500 GtC, 1990–2100; or 1,420 GtC, 2000–2100 (IPCC, 1995).

67. This gloom-hope perspective on the prospects for nuclear power is widely shared by governments. In the text agreed to by government delegations at the final plenary session for Working Group II of the IPCC's second assessment report, it is stated that “nuclear energy could replace baseload fossil fuel electricity generation in many parts of the world if generally acceptable responses can be found to concerns such as reactor safety, radioactive waste transport and disposal, and nuclear proliferation” (IPCC, 1996b). Similarly, the Energy Research and Development Panel of U.S. President Clinton's Committee of Advisors on Science and Technology concluded: “Several problems cloud fission's potential as an acceptable power source today and into the future: disposal of radioactive waste; concern about nuclear weapons proliferation; concern about safe operation of plants; and noncompetitive economics... Given the projected growth in global energy demand... and the need to stabilize and then reduce GHG emissions, it is important to establish fission energy as an acceptable and viable option, if at all possible... Therefore, R&D is needed to solve the problems” (PCAST Energy Research and Development Panel, 1997).

68. Assuming a 10 percent discount rate, the value assumed in assessing all technologies in chapter 8. For a 5 percent discount rate, this report projected costs of \$1,400–2,800 per kilowatt-electric (Paffenbarger and Bertel, 1998).

69. The high cost and complexity of the LWR are related in part to its high power density—ironically the reason it was originally chosen for submarine use!

70. For example, the former chairman of the Atomic Energy Board of India was warned that the safety status of nuclear energy installations in India is far below international standards, and that in the absence of an independent regulatory body this has serious implications for public safety (Gopalakrishnan, 1999).

71. Nuclear-explosive materials are those that can sustain a fission chain reaction based on fast neutrons, which is the requirement for making a nuclear bomb. The two principal nuclear-explosive materials are mixtures of uranium isotopes that contain more than 20 percent of the fissile isotopes U-233 and U-235; and all mixtures of plutonium isotopes, except those containing a high proportion of Pu-238 (see CISAC, 1995).

72. The importance of complementing institutional measures with technological strategies was underscored recently by Evgeniy Adamov, the Russian minister of atomic energy, who has expressed the view that the risk of diversion of nuclear material is one of the key problems of the non-proliferation regime, and therefore, “no matter how efficient the inspection and safety regime in different countries may be, it is necessary to pass on to a different kind of technological cycle in nuclear energy that has built into it a mechanism to prevent the development of weapons-grade materials” (press conference transcript, 25 November 1998).

73. On the institutional side, continuing efforts are under way to strengthen the international safeguard system, export controls over key technologies, and security systems designed to prevent the theft of weapons-usable nuclear materials. Much more remains to be done in each of these areas, however—particularly because the collapse of the Soviet Union has greatly weakened controls over technologies, information, and materials in the former Soviet states. In the case of the international safeguards regime, the IAEA is critically in need of more resources, having been on a near-zero-real-growth budget even while taking on substantial new responsibilities, and the IAEA also requires strong political support to effectively implement the new safeguard measures agreed to in recent years. R&D is also needed to improve safeguard technologies, including those designed to detect clandestine nuclear activities from kilometres away and those to account more accurately for plutonium in spent fuel and in bulk processing (as occurs during reprocessing and plutonium fuel fabrication), as well as highly enriched uranium in bulk processing. For a detailed discussion of institutional strategies for reducing proliferation risks associated with nuclear power, see Walker (1999).

74. In addition, India has a small pilot reprocessing plant at Tarapur and has recently put into operation a second reprocessing plant at Kalpakkam. And Japan has a small reprocessing plant at Tokai Mura (currently shut down). Under the Carter administration, the United States abandoned plans for fuel reprocessing and plutonium recycling as a result of both nuclear proliferation concerns and poor prospective economics. Since 1990 the Russian reprocessing plant has been running at a modest fraction of its rated capacity; some of its non-Russian clients have shifted from a spent fuel reprocessing strategy to a direct spent fuel disposal strategy, and Russian reactor operators are failing to pay their bills (Berkhout, 1998).

75. For the Russian Federation’s reprocessing plants, the situation is somewhat more complex. There does not appear to be a requirement for plutonium return. Older contracts do not appear to require return of high-level wastes; high-level waste return appears to be required by at least some interpretations of Russian law, but the law is being ignored.

76. At today’s low uranium market price of \$25 per kilogram (equivalent to an oil price of less than \$0.30 per barrel), the purchase of uranium contributes to the cost of nuclear electricity less than \$0.0005 per kilowatt-hour. A 1994 study estimated that the levelised fuel cost for the once-through LWR fuel cycle is 14 percent less than for the reprocessing cycle (NEA, 1994). A more recent analysis found reprocessing and plutonium

recycling to be much less attractive economically and estimated that uranium prices would have to increase by six times before reprocessing and recycling would be economic (Fetter, Bunn, and Holdren, 1999).

77. A variety of other possibilities have been considered over the years and might still be pursued someday as alternatives to repositories, including disposal in the seabed, in miles-deep drilled boreholes, in space, and the like.

78. This cost assessment is consistent with a Framatome assessment that a particle-accelerator-based system that would transmute minor transuranics and long-lived fission products would not be competitive in electricity generation with LWRs (Valée, 1999).

79. For example, it has been recently discovered that water moves through the mountain much faster than had been thought, and thermal inclusions have been identified that may (or may not) suggest upwellings of water in the not very distant past.

80. During a period of 500,000 to 1 million years, the most exposed community 30 kilometres from Yucca Mountain (if that site becomes a U.S. nuclear waste repository) may have exposure from groundwater that is comparable to background radiation. However, only a tiny fraction of the population would be so exposed.

81. For example, recent measurements challenge the widely held technical view that the greatest long-term waste disposal hazards arise not from transuranics but from long-lived fission products. The relative lack of concern about transuranics arises from the belief that even if storage canisters eventually lose their integrity, the transuranics will not dissolve readily in reservoir groundwater because they are quite insoluble relative to long-lived fission products under both oxidising and reducing conditions. Thus, except where there would be human intrusion into the repository, the main doses to humans after long periods would be from the long-lived fission products Tc-99 and I-129, which are soluble and thus can move through groundwater pathways (STATS Committee, 1996). But recently, trace plutonium contamination was discovered in sub-surface waters in Nevada that can be unambiguously identified as having come from a nuclear weapons test 30 years earlier at the Nevada test site 1.3 kilometres from the point where the plutonium contamination was found. This measurement (Kersting, 1999) and related tracer experiments (McCarthy, Sanford, and Stafford, 1998) suggest that sub-micron-scale colloidal particles are the carriers of plutonium through groundwater. In addition, it has recently been shown that water, even at ambient temperatures, can further oxidise PuO₂ into forms for which more than 25 percent of the Pu ions exist in states that are far more soluble (Haschke, Allen, and Morales, 2000). Although these findings do not prove that such mechanisms will provide significant exposure pathways from nuclear weapons test sites or radioactive waste disposal sites, they do show that concerns about long-term waste disposal are made up of technical as well as political elements (Honeyman, 1999; Madic, 2000).

82. Vendors of heavy water reactors are also developing evolutionary advanced designs, with features similar to those being incorporated into evolutionary advanced light water reactor designs.

83. U-233, like U-233 and Pu-239, is a fissile material from which nuclear weapons can be readily made.

84. Relatively pure U-233 might be obtained by extracting chemically from spent fuel the Pa-233 precursor of U-233 before the Pa-233 (with a 27-day half-life) has a chance to decay (Glaser, 1998). Glaser (1998) also points out that if a would-be had access to relatively modest-scale uranium enrichment capacity, weapons-grade uranium could be produced from both the U-233 and the U-235 in the denatured fuel, because most of the separative work required to produce weapons-grade uranium from natural uranium has already been carried out.

85. The type of HTGR involving fixed graphite blocks has been the focus of considerable effort in several countries (including construction and operation of prototype reactors with varying degrees of success); an international consortium including France, Japan, the Russian Federation, and the United States is developing a next-generation modular design of such a system, with the idea of possibly constructing a prototype in the Russian federation. The pebble bed variant of the HTGR has been

the focus of development in several countries (including construction and operation of an early prototype in Germany some years ago), and a pebble bed modular reactor is now the focus of an embryonic international effort led by Eskom, the electric utility of South Africa, with participation from German experts and MIT, among others.

86. Less than 4.5 megawatts per cubic metre, relative to 100 megawatts per cubic metre for an LWR.

87. The nuclear LWR-FBR nuclear vision was epitomised by the US Atomic Energy Commissions' 1973 projection that by 2000 the United States would get half its electric power from 400 FBRs and 600 LWRs.

88. The United States abandoned the 300-megawatt-electric Clinch River Breeder Reactor demonstration project in 1983, after spending \$7 billion, and cancelled the follow-on Integral Fast Reactor in 1994. The United Kingdom completed an FBR prototype in 1974 but shut it down in 1994, after abandoning plans for construction of a follow-up full-scale demonstration project. France completed the 300-megawatt-electric Phenix prototype FBR in 1973 and \$5 billion full-sized, 1,200-megawatt-electric Super Phenix in 1985. Although the Phenix has been relatively trouble free, the Super Phenix has been shut down for long periods as a result of sodium leaks and related safety issues, and the French government recently announced that the Super Phenix will be dismantled. Germany completed an FBR programme; a sodium coolant accident at the Monju prototype FBR in 1995 has put the Japanese FBR programme largely on hold, although some variant of the plutonium FBR remains a major objective of Japanese nuclear energy policy (Hori and others, 1999). The Russian Federation operates the world's only remaining commercial-scale breeder (the BN-600 at Beloyarsk) and has the world's only remaining plans for near-term construction of additional commercial breeders (the BN-800), but construction of these has been stopped for many years for lack of funds. The BN-350 breeder reactor in Kazakhstan was recently closed, with no plans for replacement.

89. Consider implications for plutonium management if the world nuclear industry evolves according to the high-nuclear-growth scenario given above, with 6,500 gigawatts-electric of installed nuclear capacity in 2100. Suppose also that, by that time, uranium resource constraints will have led to a decision to introduce conventional plutonium recycling. Each one-gigawatt-electric power plant under such circumstances would discharge in its spent fuel 10^3 kilograms of plutonium each year that would be recovered via reprocessing and used in fresh fuel. The amount of plutonium circulating in global commerce would be 6.5 million kilograms per year. The amount of plutonium needed to make a nuclear weapon is less than 10 kilograms. Because of the daunting institutional challenges associated with preventing significant quantities of this plutonium from being diverted to weapons purposes, it would be desirable to have available more proliferation- and diversion-resistant nuclear technologies that would not be so difficult to manage institutionally.

90. Two ground-based reactor test facilities were constructed, and eight nuclear submarines powered with lead-bismuth-cooled reactors were built (Crodnikov and others, 1999).

91. In contrast to conventional plutonium breeders, for which plutonium production targets are greater than plutonium consumption rates.

92. The reactor for the proposed system would be compact (with a core volume of 6.8 cubic metres). The reactor core would be sealed so that individual fuel assemblies could not be removed. The entire sealed core could be delivered as a unit to the power plant site and returned to the factory at the end of its useful life.

93. High security would have to be provided to deter theft of sealed reactor cores during transport to (as well as from) deployment sites.

94. It would take 10–15 years to develop and build an experimental reactor and 20 years before a demonstration unit could be put into operation (Orlov and others, 1999). Thus, even with a dedicated effort, deployment could not take place for decades.

95. Assuming a 1970s-vintage version of this technology, for which the uranium fuelling requirements (with a tails assay of 0.1 percent U-235 at the uranium enrichment plant) are estimated to be 13.5 times 10^{-6} kilograms per kilowatt-hour, which is 64 percent of the uranium fuelling required for an LWR (Feiveson, von Hippel, and Williams, 1979).

96. To this end, Bunn (1999) sees the need for independent research by social and political scientists on the roots of public attitudes on nuclear technology.

97. Such a strategy was suggested by Lidsky and Cohn (1993).

98. In contrast to the situation for the renewables and energy efficiency communities, those seeking expanded roles for fossil fuels in a greenhouse-gas-constrained world probably do not need political support from the nuclear industry to get a fair chance to prove whether or not decarbonised fossil energy strategies are viable.

99. This strategy was also suggested by Lidsky and Cohn (1993).

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