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The Potential for Reducing CO_2 Emissions with Modern Energy Technology: An Illustrative Scenario for the Power Sector in China

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INTRODUCTION

Many policy makers believe that the pursuit of environmental goals will slow the rate of economic growth. Indeed, this notion is the basis of the philosophy that guided many developing countries at the time of the UN Conference on the Human Environment in 1972 in Stockholm: develop first; protect the environment later. Since that time, wide recognition of the high costs of environmental degradation has led to the emergence of a now predominant alternative view, well articulated in the 1987 report of the World Commission on Environment and Development,[13] that developmental and environmental goals must be pursued simultaneously—a perspective that will be the integrating theme of the UN Conference on Environment and Development to be held in Brazil in June 1992.

While it is becoming generally accepted that the societal benefits offered by environmental initiatives will often justify their costs, what is not well appreciated is the potential for using environmental concerns as a stimulus for introducing modern technology that offers broad economic as well as envi-

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ronmental benefits.[14] It is entirely possible that the adoption of artfully crafted environmental policies could speed up the rate of technological innovation and thus speed up the rate of economic development as well. This thesis will be illustrated here via a case study exploring the prospects for modern energy technologies that offer the promise of simultaneously dramatically reducing CO_2 emissions and local air pollution, while providing electrical services at competitive cost.

The case study developed here is a scenario for the power sector of China looking 50 years into the future. The scenario is constructed in such a way that total CO_2 emissions from the power sector are the same in 2039 as in 1989. As the scenario represents a radical departure from present plans, some assumptions may be unrealistic. The exercise is intended, however, not to forecast the future but to explore whether such a goal might be plausibly achievable at acceptable cost. To the extent that the assumptions are plausible and the indicated costs attractive, the analysis can suggest strategies that should be pursued further, both in China, and in the international community that is seeking a basis for cooperative approaches for coping with greenhouse warming and other environmental issues.

The scenario (see table 1, page 27, and figure 1 for details) combines the following elements:

- efficient electricity end-use
- hydroelectric power
- nuclear power
- efficient gas turbine technologies fired with natural gas
- use of coal-derived hydrogen in fuel cells
- biomass-integrated gasifier/gas turbine technologies.

While modern technology is emphasized, the scenario involves only systems that could be commercialized in the 1990s—no long-term technological possibilities are taken into account. In what follows each element of the scenario is discussed in turn.

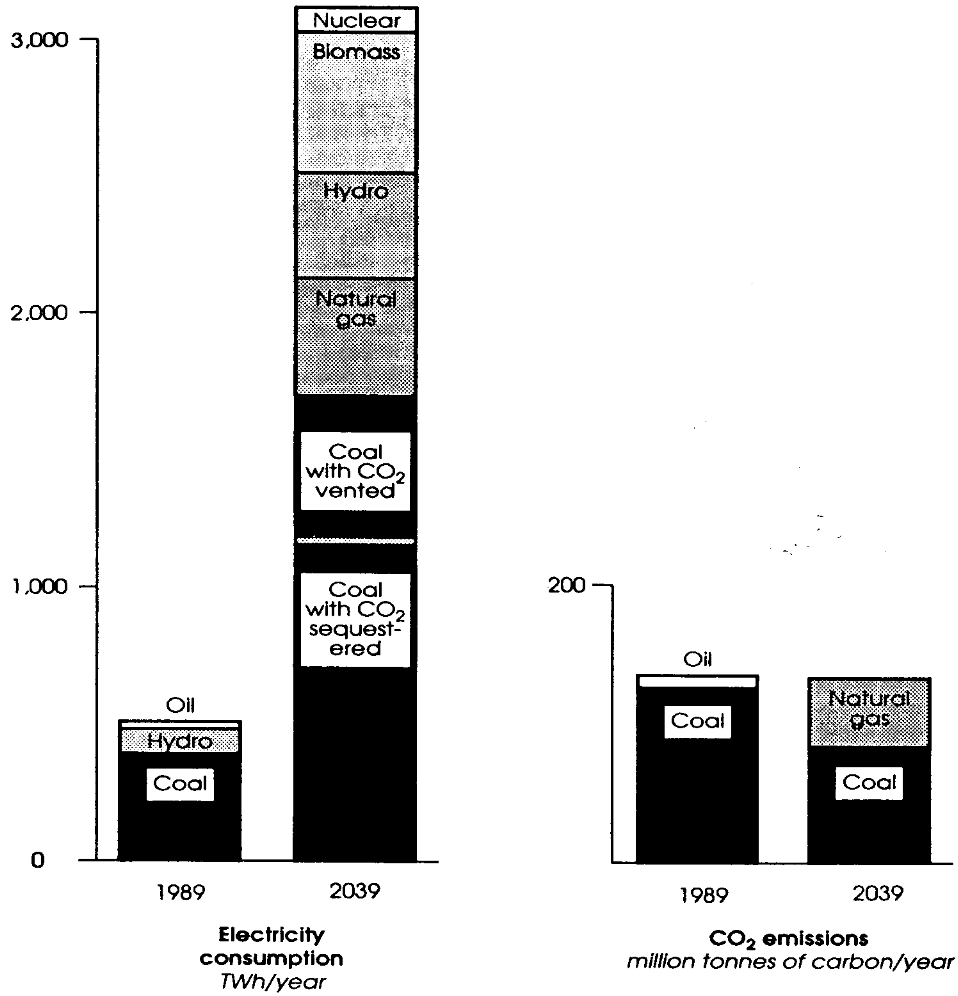


Figure 1: Low CO_2-emitting scenario for electricity consumption in China in 2039, compared to electricity consumption in 1989, along with the associated CO_2 emissions. (See table 1, page 27, for details.)

EFFICIENT ELECTRICITY END-USE

Emphasis on efficient use of energy warrants high priority in energy planning in developing countries.[5,15] This is recognized in China.[16]

It has been shown that with emphasis on efficient use of energy based on technology that is either commercially available or could be commercialized in just a few years, it would be feasible to achieve, for a hypothetical developing country, a living standard up to that of the Western Europe, Japan, Australia, and New Zealand region in the mid 1970s, with a final energy use rate of about 1 kilowatt per capita[5]—only slightly higher than in developing countries at present, on average. For comparison, final energy use in China in 1989 was as follows, in kilowatts per capita:*

Direct use of commercial fuel (from table 3, page 30)	0.631
Direct use of noncommercial (biomass) fuel[17]	0.268
Electricity consumption (from table 3, page 30)	0.050
Total	**0.949**

In addition to emphasis on efficient end-use technology, the energy-efficient "1 kilowatt" future requires a shift to modern energy carriers—away from noncommercial fuels (e.g., fuelwood) that are used inefficiently to liquid, gaseous, and processed solid fuels and electricity that can be used more efficiently. Specifically, energy is used at the following rate,[5] in kilowatts per capita:

Direct use of commercial fuels	0.839
Electricity consumption	0.210
Total	**1.049**

The electricity scenario constructed in this paper is based on this "1 kilowatt future." It is assumed that the electricity consumption levels for the scenario are realized in 50 years time, when China is projected to have a population of 1.7 billion,[6] up from 1.1 billion in 1989. Under these conditions, the average growth rate for electricity consumption would be 3.8 percent per year, 1989–2039.

This rate of growth can be compared to the growth rates for electricity demand in Centrally Planned Asia projected by the Response Strategies Working Group (RSWG) of the Intergovernmental Panel on Climate Change (IPCC).[18] The RSWG low economic growth scenarios (for gross domestic prod-

* These are continuous average rates of consumption—i.e., 1 gigajoule per year = 0.0317 kilowatts.

uct [GDP] growing at an average rate of 2.9 percent per year, 1985–2050) have average electricity demand growth rates of 2.1 to 2.6 percent per year to the year 2050. The RSWG high economic growth scenarios (for GDP growing at an average rate of 4.9 percent per year, 1985–2050) have average electricity demand growth rates of 3.8 to 4.5 percent per year to 2050—specifically 4.5 percent per year for the RSWG "business-as-usual" variant, which involves "moderate energy efficiency" improvements, and 3.8 to 4.0 percent per year for the variants that involve "high energy efficiency." Thus, the electricity demand scenario constructed here is consistent with the high economic growth, high energy efficiency scenarios constructed by the RSWG of the IPCC. Because there is a wide range of opportunities for providing energy services more cost effectively through investments in energy efficiency improvement compared to investments in the equivalent amount of energy supply expansion in developing and centrally planned economies,[15,16,19] the RSWG scenario variants emphasizing energy efficiency are likely to be less costly than the business-as-usual variants.

HYDROPOWER

Hydropower is attractive from the perspective of greenhouse warming. Moreover, potential hydropower resources in China are large—some 380 gigawatts of electrical capacity (GW_e).[1] At the 1989 average capacity factor of 39 percent[1] this much capacity could provide about 11 times as much hydroelectricity as was generated in China in 1989 (see table 4, page 31). However, hydro projects are increasingly coming under attack by environmentalists. In China the hydropower debates have focused for several decades on whether or not to go forward with the proposed Three Gorges Project, which could have a capacity of up to 18.7 GW_e. The fate of this project is still uncertain. For the purposes of the present analysis it is assumed that hydropower remains a controversial resource and that over the next 50 years hydropower is developed only to a level twice that being planned for the year 2000 (compare tables 1 and 4, pages 27 and 31)—a level that is only about one third of the potential. This means that after the year 2000, hydroelectric generation would grow at an average rate of just 1.3 percent per year (compared to a rate of 6.8 percent per year projected by the World Bank for the period 1989–1999 (see table 4, page 31). As a result, the hydropower share of total electricity would be reduced from 20 percent in 1989 to 13 percent in 2039.

NUCLEAR POWER

Like hydropower plants, nuclear power plants emit no greenhouse gases. While there is no nuclear power at present in China, some 3.9 GW_e of nuclear capacity is planned for the year 2000, at which time nuclear power would account for 2 percent of total electricity production (see table 4, page 31).

In many parts of the world the future of nuclear power is clouded by public antipathy arising mainly from concerns about the accidents at Three Mile Island and Chernobyl and about the hazards of radioactive waste disposal. These concerns are not yet very widespread in China, but this situation might change after the first plants are introduced.

Moreover, if nuclear power were developed worldwide on a scale sufficient to have a major impact on the problem of global warming, the nuclear weapons connection to nuclear power would come into sharp focus.[29] With large-scale development of nuclear power, concerns about availability of uranium resources would create interest in shifting from present nuclear power technology, which can make use of only about 1 percent of the energy content of uranium, to breeder reactors, which can make use of up to 50 percent of natural uranium by efficiently converting uranium-238 (which makes up 99.3 percent of natural uranium) into plutonium-239, which, like uranium-235, is a good reactor fuel. With breeder reactor technology, uranium resources would be adequate to support a large-scale global commitment to nuclear power for thousands of years.

However, in addition to being a good reactor fuel, plutonium is also a material from which nuclear weapons can be made. While the deployment of plutonium-based nuclear power technologies in countries that already have nuclear weapons would not increase proliferation risks directly, the wide use of these technologies there would make them attractive to non-nuclear weapons countries as well. It is not likely that a stable world order can evolve when certain "sensitive technologies" are denied to some countries but allowed in others; a sustainable situation is likely to be possible only if the same rules apply to all countries. Accordingly, large-scale development of nuclear power will probably be feasible only if new diversion-resistant nuclear power technologies are developed[29] and if new international institutions are introduced to tightly control sensitive nuclear technologies.[29,30,31] Without such controls the proliferation of nuclear weapons from advanced nuclear power cycles is likely to become a major global problem.

It is highly uncertain at this time whether the risks of nuclear accidents and waste disposal can be made acceptable to the public, and whether it will be possible to achieve the level of international cooperation needed to reduce proliferation risks associated with large-scale nuclear power development to acceptable levels. Moreover, diversion-resistant nuclear technologies suitable for large-scale nuclear development are not being planned. Accordingly, it is assumed for the electricity scenario that nuclear power does not become a major electricity source over the next half century in China, and that by 2039 the level of nuclear power development is just four times the level planned for the year 2000 (a level comparable to that in France in the early 1980s). Nuclear power would then account for 2.6 percent of electricity generation (see table 1, page 27, and figure 1).

EFFICIENT GAS TURBINE TECHNOLOGIES FIRED WITH NATURAL GAS

Natural gas is the cleanest of the fossil fuels. It is the fossil fuel of choice in considering the greenhouse problem. Natural gas releases 40 percent less CO_2 than coal per unit of fuel burned (see table 2, page 29, note a). The greenhouse benefit will often exceed this because natural gas conversion technologies can be made more energy-efficient than coal conversion technologies.

Natural gas consumption and production in China in 1989 was only 0.6 exajoules—about 2 percent of total primary energy consumption (see table 3, page 30). Yet proved reserves are substantial—39.0 exajoules[4]—and, according to China's national oil and gas resources assessment completed in 1987, total natural gas resources on land and on the continental shelf of China are large—about 1,300 exajoules.[1] Thus, the long-term outlook for natural gas in China is auspicious.

Because of this favorable long-term outlook for natural gas, it is assumed in this paper that over the next 50 years natural gas consumption and production expand to a level of 13 exajoules per year. At this level, gas resources would last for a century. To support this level of production, proved reserves of natural gas would have to be expanded 3.3-fold over the next 50 years, to 130 exajoules, assuming a reserve/production ratio of 10, which is characteristic of a mature natural gas industry.

Natural gas–fired advanced gas turbine cycles are being used increasingly for power generation in many parts of the world. They offer the advantages of low unit capital cost, low pollutant emissions, and high efficiency.[20] Efficiencies have been increasing rapidly, and commercially available natural gas–fired gas turbine/steam turbine combined cycles available today can be at least 50 percent efficient (LHV* basis, see figure 2), compared to 35 percent for mod-

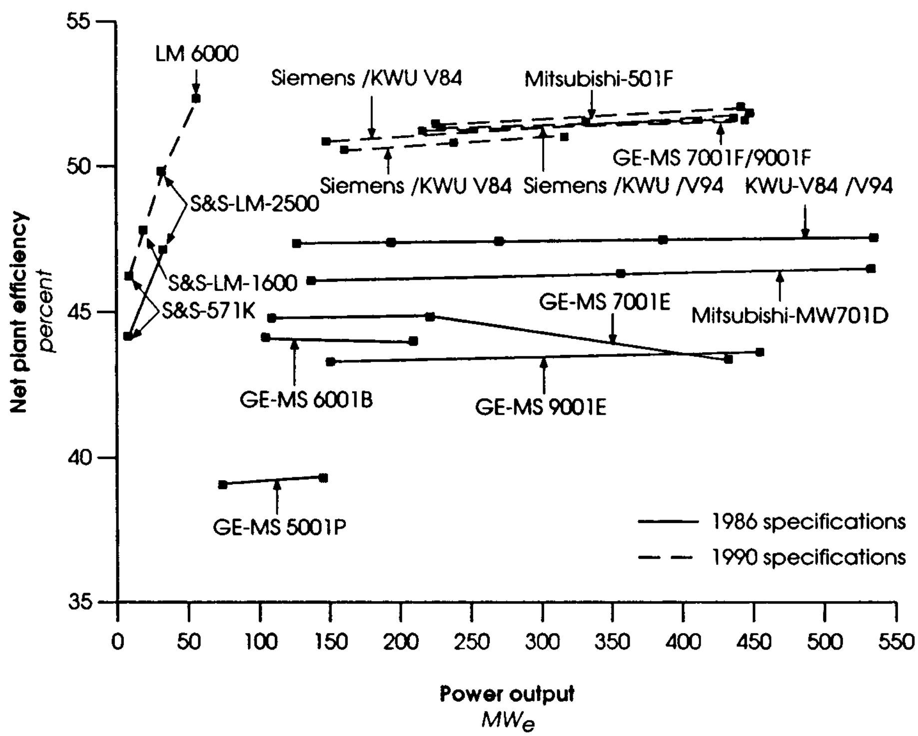


Figure 2: The pace of technological change for gas turbines is rapid, with the efficiencies of the most efficient gas turbine/steam turbine combined cycles now offered commercially being more efficient by almost 5 percentage points than the most efficient cycles offered commercially five years ago, as indicated by this graph.[28]

* The lower heating value of the fuel, which does not include the latent heat of condensation for water vapor in the combustion-product gas.

ern coal-fired steam-electric plants with environmental controls (compare tables 5 and 6, pages 32 and 33). Moreover, beyond the turn of the century advanced gas turbine power plants fired with natural gas are likely to reach efficiencies of the order of 60 percent, because of the prospect of continuing technological improvement (see figure 3).

Because of their high efficiency and low capital costs, combined cycles on the market today would be competitive with clean-burning coal-fired steam electric plants up to very high natural gas prices (compare tables 5 and 6, pages 32 and 33). These plants emit 60 percent less CO_2 than coal-fired steam-electric plants per kilowatt-hour of electricity generated (see table 2, page 29).

It is assumed that by 2039 one fourth of gas production in China will be committed to electricity production via gas turbine/steam turbine combined cycles, having an average efficiency of 50 percent. This implies that 50 years

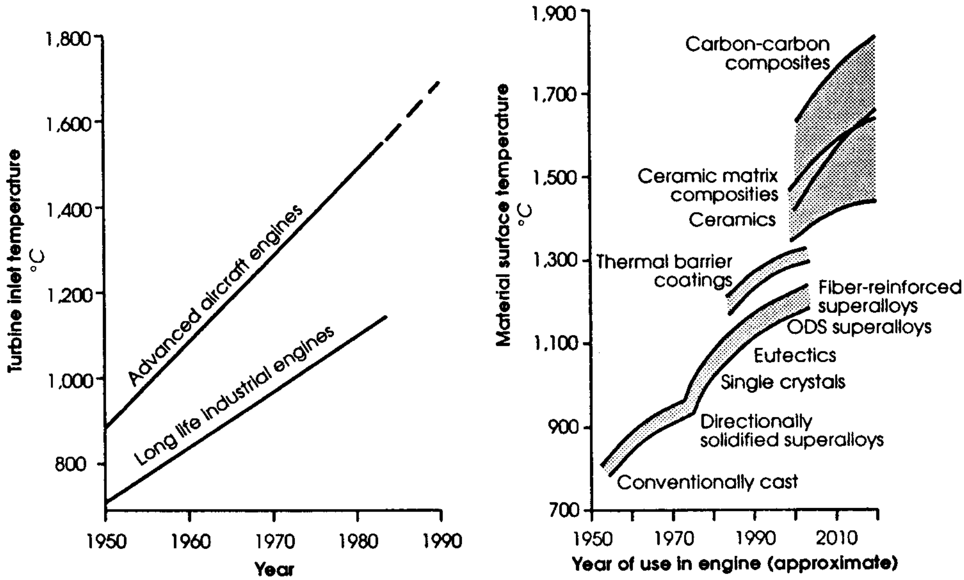


Figure 3: The trend in turbine inlet temperature for advanced aircraft jet engines (top left) and long-life industrial engines (bottom left)[43] and turbine blade material operating temperature (right).[44] Note that since the end of World War II, the turbine inlet temperature for advanced aircraft engines has increased at an average rate of 20 °C per year.

In the decades immediately ahead efficiencies of natural gas–fired gas turbine-based power cycles of up to 60 percent can be expected, as the result of expected improvements in turbine blade materials and blade cooling technologies, as well as the introduction of advanced thermodynamic cycles based on the gas turbine.

from now natural gas would provide about 10 percent more electricity than coal does now, while emitting 60 percent less CO_2 (see table 1, page 27, and figure 1).

Despite the favorable long-term outlook for natural gas and gas turbine power cycles, China has no major plans under way for expanding natural gas production in general or for power generation in particular. Natural gas is being considered primarily as a chemical feedstock for industry (e.g., for ammonia and petrochemicals production). It is also being considered as a fuel for cooking. Various "town gases" (natural gas, liquefied petroleum gas, and oil- and coal-derived synthetic gases) are being emphasized for cooking in urban areas, in part to offset the pollution problems caused by direct use of coal for cooking. The central government is planning to have the number of people supplied by town gas increase from 40 million in 1987 to 120 million in 2000. But the total amounts of gas involved are minuscule compared to total energy consumption (see table 3, page 30)—0.14 exajoules in 1987 and up to 0.42 exajoules in 2000, with natural gas accounting for only 0.04 exajoules in 1987 and 0.22 exajoules in 2000.[32] Up to the year 2000 no significant amount of natural gas–based power generation is being planned (see table 4, page 31).*

The transfer to China of Western technology for the production, transport, and use of natural gas could probably speed up the rate at which natural gas is developed in China and the diversification of its use to include power generation. A key question regarding the transfer of such technology is how the earnings from the associated investments could be repatriated, in light of the fact that the Chinese currency is not readily convertible. This transfer could be accomplished by barter. A barter arrangement that might be attractive in a greenhouse-constrained world would involve investors taking their earnings in energy-efficient consumer appliances that could be produced at competitive costs in China because of low labor costs.† Such barter arrangements could lead to reductions in CO_2 emissions both in China (through the accelerated

* It is noteworthy, however, that in 1990 two 50 megawatt (MW_e) steam-injected gas turbine power systems based on the General Electric LM-5000 were purchased for independent power production by the Shenzhen Huaneng Economic Development Corporation in Shenzhen, China. The steam-injected gas turbine is an aeroderivative turbine technology offering good performance at modest scale.[20]

development of natural gas resources), and in the rest of the world, where the bartered appliances would be used.

USE OF COAL-DERIVED HYDROGEN IN FUEL CELLS

As China has enormous coal resources, efforts should be made to identify ways of using coal that would be consistent with a greenhouse-constrained world. One promising approach, which is strongly linked to natural gas development, involves producing a hydrogen-rich fuel gas from coal at an overall conversion efficiency of 73 percent (LHV basis), with sequestering of the recovered CO_2 in depleted or near-depleted gas wells.* [3]

The first step in the process involves using commercially ready oxygen-blown coal gasification technology (Shell, Dow, or Texaco gasifiers) to produce syngas—a mixture of CO and H_2. The syngas can then be passed through a water-gas shift reactor (well-established technology), where most of the heating value of the CO is shifted to hydrogen by reacting the CO with steam:

$$CO + H_2O_{(g)} \rightarrow CO_2 + H_2.$$

Both gasification and the shift reaction take place at high pressure (24 atmospheres). The product gas is mostly hydrogen and CO_2; about 92 percent of the

† While visiting department stores in China in July 1991, the author discovered that a wide range of compact fluorescent lightbulbs are produced in China and sold at prices in yuan that are roughly the same as the prices in dollars for comparable bulbs sold in the US. Compact fluorescent lightbulbs are energy-efficient bulbs that can be screwed into ordinary incandescent bulb sockets. They require only about one fourth as much electricity as incandescents that provide the same light output. If the observed prices are approximately true market prices, these Chinese bulbs would be highly competitive in Western markets, since the official exchange rate is more than 5 yuan per dollar.

* The prospects for permanent sequestration of recovered CO_2 in exhausted gas wells needs further investigation. However, preliminary analyses indicate this would be a viable strategy. According to an analysis by the Shell International Petroleum Company of the potential for sequestration in depleted natural gas fields in the Netherlands[21]: "...we consider the injection into gas fields a safe and secure way to dispose of carbon dioxide, as long as the initial reservoir pressure is not exceeded. In this way, caprock integrity can be guaranteed. Escape of carbon dioxide to the atmosphere through leaking wells is unlikely if the wells are properly abandoned at the end of the project."

heating value of the gas is accounted for by hydrogen. Because it is highly concentrated, the CO_2 is readily removed using commercially available physical absorption processes (for example, Selexol); in practice about 88 percent of the carbon in the original coal can be recovered this way. The recovered CO_2 can then be compressed to high pressure, transported to depleted or near-depleted natural gas wells (or other secure sequestering sites) and injected into the wells for permanent sequestering. Finally, the resulting hydrogen-rich fuel gas can be purified (to 99–99.999 percent purity), if desired, at low incremental cost, using commercially available pressure-swing adsorption technology. About 85 percent of the hydrogen (with $0.85 \cdot 92 = 78$ percent of the heating value of the fuel gas) can be recovered this way in the stream of purified hydrogen. The remaining hydrogen ends up with the residual gas stream, which accounts for 22 percent of the heating value of the fuel gas. The purified hydrogen and residual fuel gas might be consumed in fuel cells and combined cycle power plants, respectively.

Preliminary calculations exploring the economics of and potential for this technology in China are presented in tables 7–9 on pages 34–37. The economics are illustrated for a hypothetical scenario whereby hydrogen produced from minemouth coal in Shanxi Province in northern China would be transported by pipeline 1,600 kilometers to markets in the northeast of China.

Overall, costs would be lowest if hydrogen were used not in conventional fossil fuel systems but with technologies that can exploit the unique properties of hydrogen. The optimal technology for utilizing hydrogen is probably the fuel cell, which can convert hydrogen directly into electricity without first burning it to make heat—thus avoiding the "Carnot" thermodynamic trap. The fuel cell is a modular technology that can be deployed in dispersed cogeneration applications, providing both electricity and heat, either for industrial process heating or district heating. Hydrogen fuel cells are also extraordinarily clean power generators, with water vapor as the only chemical product of operation.

While in the future a variety of fuel cells will be available with electrical efficiencies of 60–70 percent and the capacity for providing by-product heat at very high temperatures (e.g., 1,000 °C for the solid oxide fuel cell), the present electricity scenario exercise is restricted to what can be achieved with phosphoric acid fuel cells—a first-generation fuel cell that is now becoming commercially available and is characterized by more modest efficiencies and much lower operating temperatures.

Most commercial activity for this technology is taking place in Japan, where a 4.5 megawatt (MW_e) unit went on line in 1983 and a 11 MW_e commercial demonstration plant was built in 1990, both at the Goi station of Tokyo Electric Power Company, located in Ichahara City on the north shore of Tokyo Bay. Plans in Japan call for installing up to 1,900 MW_e of dispersed fuel cell units (with unit capacities ranging from 200 kilowatts [kW_e] to 10 MW_e) before the turn of the century.[33] Worldwide, management consultants at Arthur D. Little International are projecting a fuel cell market of 4,000 MW_e per year by the year 2000, most of which would be based on phosphoric acid fuel cells.[34]

It is likely that modest-scale hydrogen-fueled phosphoric acid fuel cells would be able to convert about 50 percent of the hydrogen fuel energy to electricity, plus another 30 percent to useful heat (see figure 4 and table 9, page 37). The heat cogenerated this way would obviate the need to burn extra coal to provide this heat in a separate boiler installation. As a result, if the separated CO_2 (accounting for 88 percent of the carbon in the coal) is sequestered, the net emissions of CO_2 per kilowatt-hour of electricity produced this way would actually be slightly negative (see table 2, page 29).

Heat is generated in phosphoric acid fuel cells at a temperature of about 200 °C. While this heat would be too low in quality for many industrial process operations, it is ideal for district heating systems, which usually involve the centralized generation of heat and its distribution as hot water to dispersed users in residential and commercial buildings.

Thus, phosphoric acid fuel cells would seem to be well suited for district heating applications in cities of northern China, where large-scale district heating projects are under development. The central government has set an ambitious target for district heating—to cover 20–25 percent of the residential heating area in the official heating zone (in the north of China) by the year 2000.[32] As in the case of town gas, these district heating projects are motivated in large part by concerns about the air pollution associated with direct coal-fired space heating in buildings. Replacing distributed coal heaters with centralized heat production in coal-fired cogeneration plants greatly facilitates pollution control. The district heating infrastructure now being built up in Chinese cities facilitates a shift to fuel cells, which might in time come to

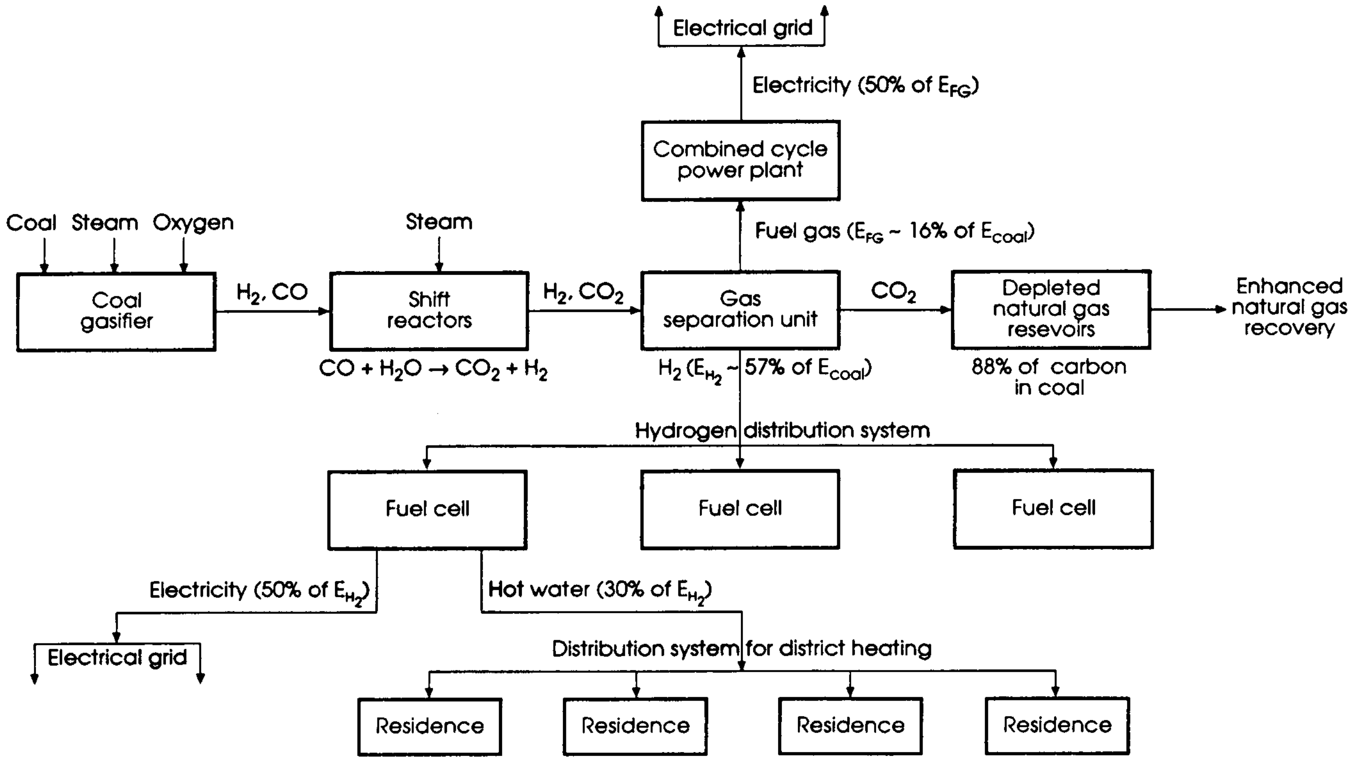


Figure 4: Here coal-derived hydrogen is used to cogenerate electricity and heat for buildings (space heat and domestic hot water) with phosphoric acid fuel cells. The hydrogen is produced from coal via oxygen-blown coal gasification. The output of the coal gasifier is a syngas, consisting mainly of hydrogen and carbon monoxide. The carbon monoxide then reacts with steam to produce hydrogen and carbon dioxide in water-gas shift reactors. Carbon dioxide and purified hydrogen are then separated from the gaseous mixture that exits the shift reactors. The purified hydrogen is transported by pipeline to distributed fuel cells that are linked to a district heating network. The separated CO_2 is compressed and sent via pipeline to natural gas fields, where it is sequestered in depleted natural gas reservoirs. Enhanced natural gas production made possible with CO_2 injection might pay in part for the cost of sequestration. The residual fuel gas (mainly hydrogen and carbon monoxide) generated at the gas separation unit is burned locally to produce electricity in gas turbine/steam turbine combined cycle power plants.

replace coal-fired steam-turbine cogeneration systems as the heat sources.

The electricity cogenerated with fuel cells could probably not compete with electricity from polluting, central-station coal plants. However, if the alternative were instead electricity produced from central-station power plants with tight controls on emissions of sulfur dioxide (SO_2) and particulates, such as those that are operative in the United States, it appears that these fuel cells might be able to compete. The high efficiencies of such power plants in the production of both electricity and heat, along with their expected lower capital costs, and the elimination of electrical transmission and distribution costs and losses (because the electricity can be generated at the point of demand) make the prospects good that electricity from phosphoric acid fuel cells fueled with hydrogen would be competitive with electricity from coal-fired steam-electric plants with emission controls—even if the hydrogen fuel had to be transported as much as 1,600 kilometers from the place where it was produced, and whether all or only half the heat cogenerated in the fuel cells could be recovered for useful purposes (compare tables 5 and 9, pages 32 and 37).*

It might be feasible to pay for part of the extra costs of sequestering CO_2 by enhanced recovery of natural gas that would arise from repressurization of the gas reservoir.† While there would often be some contamination of the recovered natural gas with the reinjected CO_2, such gas would still be a good fuel for power generation in local combined cycle plants,‡ even though it would not be suited for long-distance pipeline transport at high contamination levels.

In addition, a new process for making synthesis gas (syngas) from methane might make natural gas contaminated with CO_2 much more interesting economically. (Synthesis gas, a mixture of CO and H_2, is a feedstock used in the production of a wide variety of chemicals and fuels, including methanol,

* District heating systems could provide for both space heating and domestic water heating needs. As space heating requirements are highly seasonal, not all the cogenerated heat can be used in many instances.

† Enhanced oil recovery via CO_2 injection is well-established technology. In the United States, there are over 3,500 kilometers of CO_2 pipelines associated with enhanced oil recovery operations, including one 800 kilometer pipeline operated by Shell Pipeline Corporation and one 650 kilometer pipeline operated by ARCO Pipeline that carry CO_2 from natural CO_2 reservoirs in Colorado to oil fields in Texas, and one 350 kilometer pipeline operated by Amoco Pipeline that carries CO_2 from New Mexico to Texas.[42]

hydrogen, and ammonia.) The usual way of producing syngas from methane is to reform it with steam in the presence of an appropriate catalyst. A new process devised by a group at Oxford University involves reforming methane with CO_2 instead. Previous attempts to make syngas this way have failed or have resulted in the formation of carbon that "cokes up" the reactor, making frequent cleaning necessary. The new approach involves using an existing catalyst in a new way that avoids carbon formation. Two British companies, British Gas and Air Products, are carrying out trials to test the feasibility of the process.[35] This possibility warrants close investigation.

For the present analysis, however, no credit is taken for enhanced natural gas recovery. Piping CO_2 300 kilometers for sequestration in abandoned gas wells would increase the cost of electricity by 11 percent (see table 9, page 37).

If it should turn out that no credits can be taken against the cost of CO_2 sequestration for enhanced natural gas recovery, then, alternatively, it would be desirable to find ways by which the global community could share in paying for these costs, since the benefits of reduced CO_2 emissions would be shared globally. The cost of sequestering the separated CO_2 in abandoned gas wells located some 300 kilometers from the hydrogen production site is estimated to be about \$33 per tonne of carbon*—an amount that is quite modest compared to many estimates of the cost of reducing CO_2 emissions.[22,23] When less costly options for reducing emissions elsewhere in the world have been exhausted, it would be more economically efficient for the world community to invest in this

‡ The amount of extra natural gas that might be produced this way is uncertain and reservoir-dependent.[21] However, each 1 percent increase in the amount of natural gas recovered from the reservoir via CO_2 injection would have an energy value of 0.017 gigajoules per gigajoule of hydrogen-rich gas produced from coal. If this natural gas were used at the wellhead in combined cycle plants for power generation, the electricity would be competitive with electricity from coal plants even if the natural gas price were as high as \$4.5 per gigajoule (see tables 5 and 6, pages 32 and 33). Thus, the added natural gas production would be worth \$0.07 per gigajoule of produced hydrogen-rich gas, for each 1 percent increase in natural gas recovery. For comparison, the cost of CO_2 injection is about \$1 per gigajoule of produced hydrogen-rich gas (see table 7, page 34).

Substantial levels of contamination could be tolerated in the recovered gas. If the recovered gas were one third CO_2, the total percentage of injected CO_2 that would be released to the atmosphere would be less than 5 percent. Moreover, if this contaminated gas were used for power generation in a combined cycle plant, the CO_2 emissions would be 37 percent less per kilowatt-hour than for a modern coal steam-electric plant (see table 2, page 29).

scheme for reducing emissions rather than to invest in more costly options elsewhere.

How much fuel cell and associated combined cycle electricity could be produced from the produced hydrogen and residual fuel gas with sequestering of the separated CO_2? This cannot be answered with a high degree of confidence without detailed study. But to give an indication of the potential, it is assumed here that the sequestration rate is equal to the gas field capacity freed up each year as a result of extracting natural gas. If the gas reservoirs were repressurized to their original pressure with the injected CO_2, the amount of carbon that could be stored as CO_2 would be about 1.4 times the amount of carbon originally in the reservoir as natural gas.[3] For a natural gas production rate of 13 exajoules per year, the amount of electricity that could be produced by fuel cells and associated combined cycles would be about three times that provided by coal-fired steam-electric plants in 1989 (see table 1, page 27, and figure 1).

Upon reaching the sequestering capacity of gas wells, the total CO_2 emissions from natural gas–fired combined cycles and fuel cells and combined cycles fueled with coal-derived gases would be only 15 percent of the emissions in 1989 (see table 1, page 27). Thus, if all presently operating fossil fuel–fired steam-electric plants were retired by 2039, this coal-derived gas strategy could be further expanded with venting to the atmosphere of the separated CO_2, without violating the CO_2 emissions constraint of this scenario. (Note that, even with venting, the electricity produced with this fuel cell/combined cycle strategy would result in 30 percent less emissions per kilowatt-hour than that from new low-polluting coal-fired steam-electric plants [see table 2, page 29].) Overall, 4–5 times as much electricity from coal as in 1989 could be provided with these strategies (sequestering plus venting variants), without violating the CO_2 emissions limit of this scenario (see table 1, page 27, and figure 1).

While the construction of this coal-based hydrogen strategy was motivated by concerns about greenhouse warming, China might well want to adopt the key technologies involved for reasons that have nothing to do with this prob-

* From table 7, page 34, it is seen that the cost of sequestration is $1.00 per gigajoule of hydrogen-rich fuel gas or 0.728·$1.00 = $0.73 per gigajoule of the coal from which it is derived. Since 88 percent of the 25.5 kilograms of carbon contained in a gigajoule of coal would be sequestered as CO_2, the cost of sequestration would be:

$$(\$0.73/\text{GJ})\cdot(1{,}000\ \text{kg/t})/(0.88\cdot 25.5\ \text{kg carbon/GJ}) = \$33\ \text{per tonne of carbon.}$$

lem.

One key technology required is oxygen-blown coal gasification. As noted above, China is already promoting town gas for cooking, in part as a strategy for coping with urban air pollution. Gases derived from coal already account for 22 percent of town gas and this percentage is expected to rise to 28 percent by 2000.[32] While no investments have yet been made in modern, pressurized, oxygen-blown coal gasifiers, investments are being made in some cities in atmospheric pressure gasifiers (e.g., two-stage gasifiers) that produce a gas of much lower quality. While oxygen-blown gasifiers are more capital-intensive, a recent World Bank analysis points out that, on a lifecycle cost basis, the gas from a pressurized, oxygen-blown gasifier would cost about one fourth less than coal gas produced in a two-stage gasifier, while providing substantial safety, environmental, and other operational advantages.[32]

Large-scale development of natural gas is also needed for this scenario to provide the CO_2 sequestering capacity. However, even if there were no greenhouse warming problem it would be worthwhile to greatly expand the natural gas sector, in light of a wide range of economic and local environmental benefits.[36]

Other key elements of this strategy are CO_2 sequestering in natural gas fields (and the prospect of associated enhanced natural gas recovery) and the use of hydrogen-fueled phosphoric acid fuel cells. While these are the more exotic elements of the proposed strategy, China could gain familiarity with these concepts quite easily, as incremental investments associated with ongoing activities. For example, some of the hydrogen produced at a large natural gas-to-ammonia production facility might be used in fuel cell demonstration projects (e.g., employing 200 kW_e fuel cell units). Moreover, as such plants are often located near natural gas fields, some of the CO_2 generated at the ammonia plant might be recovered and injected into these gas reservoirs, allowing for closer study of the issues associated with injection.

BIOMASS-BASED POWER GENERATION

Biomass is a natural resource that is widely available in developing countries. Biomass production is inherently labor-intensive—which is important for countries that are capital-poor and labor-rich. It could also potentially provide the energy basis for rural industrialization. Moreover, if the biomass is grown sustainably, there is no net release of CO_2 and hence no contribution to the global greenhouse problem.

Biomass accounts for about 26 percent of primary energy use in China.[17] As in most developing countries, biomass is used inefficiently in China, predominantly as a noncommercial fuel in applications such as cooking. Often the biomass is not provided sustainably. According to the Chinese Ministry of Energy, the burning of fuelwood in China is carried out at a rate that is 2.6 times the sustainable rate, causing great ecological damage.[1] In most developing countries, biomass tends to be regarded as "the poor man's oil"—an energy source to move away from as development proceeds.

Biomass can be grown sustainably if biomass producers have sufficient incentive. This can be accomplished only if the biomass is not used as at present but is instead converted efficiently and competitively to high quality energy carriers (gaseous and liquid fuels and electricity) using modern conversion technologies. For such technologies biomass would command much higher market prices than at present.

At the present low world oil price the most promising method for using biomass involves making electricity. One way to produce electricity from biomass involves using steam-electric power plants. A biomass power industry based on the use of this technology was launched in the US in the 1980s. In the US installed generating capacity for biomass power plants expanded from about 250 MW_e in 1980 to nearly 9,000 MW_e by 1990.[25] This technology is economically competitive today in areas where biomass prices are low. In the US the cost of biomass in the form of residues from existing agricultural or forest product industries is often low enough for the production of competitively priced electricity with this technology, though biomass grown on dedicated plantations in the US is usually too costly. However, biomass grown on plantations in some parts of China may well be cheap enough to generate electricity in steam-electric plants competitively with coal-based power generation.[37]

With the use of advanced technology electricity could probably be produced competitively from biomass even at biomass prices that are higher than coal prices. A promising approach that will probably be commercialized in the 1990s* involves gasifying the biomass thermochemically in an air/steam environment and using the gas onsite to provide electricity in aeroderivative gas turbine-based power cycles (see figure 5). Such cycles offer the potential for achieving high efficiency and low unit capital costs at the modest scales (typically tens of MW_e) needed for biomass operations.

This prospect arises as a near-term possibility, in large part because of advances that have been made in marrying coal to the gas turbine through the use of coal gasifiers that are closely coupled to the gas turbine power plant. Some of these advances can be adapted to biomass at low incremental development cost.[10,24,25] In fact, the biomass versions of the integrated gasifier/gas turbine (IG/GT) technologies are likely to be commercialized more quickly than the coal versions, both because biomass is more reactive than coal and thus easier to gasify, and because biomass generally contains negligible sulfur. The efficient and cost-effective removal of sulfur is the major obstacle to making coal-integrated gasifier/gas turbine (CIG/GT) technology a strong competitor to coal steam-electric power utilizing flue-gas desulfurization. Biomass-integrated gasifier/gas turbine (BIG/GT) power systems are likely to be competitive with hydro, nuclear, or coal-based power generation under a wide range of conditions. A comparison of the busbar costs shown in tables 5 and 10, pages 32 and 38, indicates that BIG/GT should be able to compete with coal for biomass prices in the range \$2.4 to \$4.0 per gigajoule. While biomass delivered to BIG/GT units from plantations in the US would cost about \$3 per gigajoule with today's biomass plantation technology,[38] biomass prices seem to be much lower in China,[37,39] probably because biomass production is inherently labor-intensive, and labor is much cheaper in China than in the US. Moreover, because of the modular nature of BIG/GT technology, less new capacity would be needed to support the electrical load with this technology than with traditional large-scale technology.

While BIG/GT technology has a high technology "core" (the gas turbine is derived from the modern jet engine) that might have to be imported in most

* A 6 MW_e pilot plant is being built in the south of Sweden under a joint venture involving Ahlstrom, a Finnish gasifier manufacturer, and Sydkraft, a private electric utility located in southern Sweden. This pilot plant is expected to be operational by mid 1993. In addition, a commercial demonstration project on a scale of about 20 MW_e is being planned for a site in the northeast of Brazil. The latter is being organized as a joint venture involving both Brazilian and foreign companies and is being supported by the Global Environment Facility of the World Bank, the United Nations Development Programme, and the United Nations Environment Programme.[25]

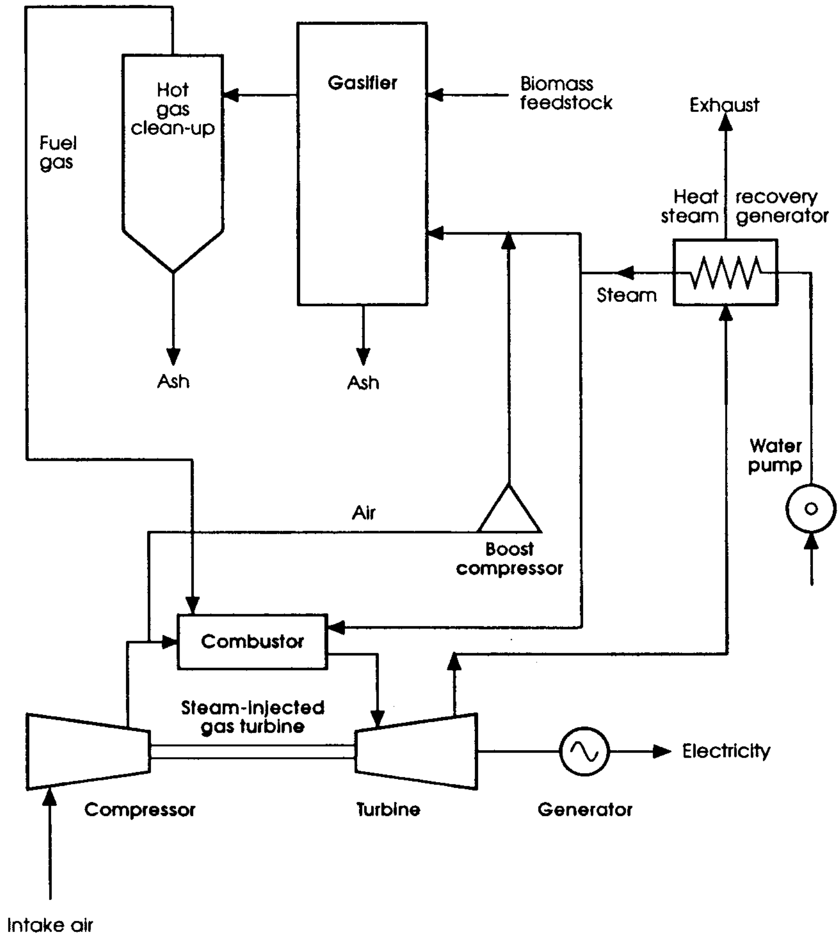


Figure 5: A first generation biomass-integrated gasifier/gas turbine (BIG/GT) power system may well involve coupling a fixed-bed gasifier (suitable for gasifying densified biomass feedstocks such as wood chips) to a steam-injected gas turbine (STIG).[25]

developing countries, most of the value added contained in a BIG/GT system is associated with relatively low technology components for which rapidly industrializing countries like China either already have a manufacturing capability or could develop one in a short period of time. And an aeroderivative gas turbine core could be serviced at centralized lease-pool maintenance facilities, so that sophisticated onsite maintenance would not be needed.[25]

A key issue is whether biomass can be produced in sufficient quantities to have a major impact on the overall energy picture. To address this issue, first-generation BIG/GT technology (see table 10, page 38) is assumed to be deployed in China on a scale such that it provides all the electricity needed in 2039, in excess of what has already been targeted above for provision by hydropower, nuclear power, natural gas, and coal-derived gases in this scenario. Under these conditions, as indicated in table 1, page 27, and figure 1, BIG/GT technology would provide about one sixth of total electricity in 2039. If the needed biomass were provided by plantations with an average productivity of 10 dry tonnes per hectare per year, some 26 million hectares of biomass plantations would be required.

There are two major uncertainties in this biomass scenario. The first is whether there will be enough land that is suitable for plantations. The second is whether yields of the order of 10 dry tonnes per hectare per year could be realized sustainably.

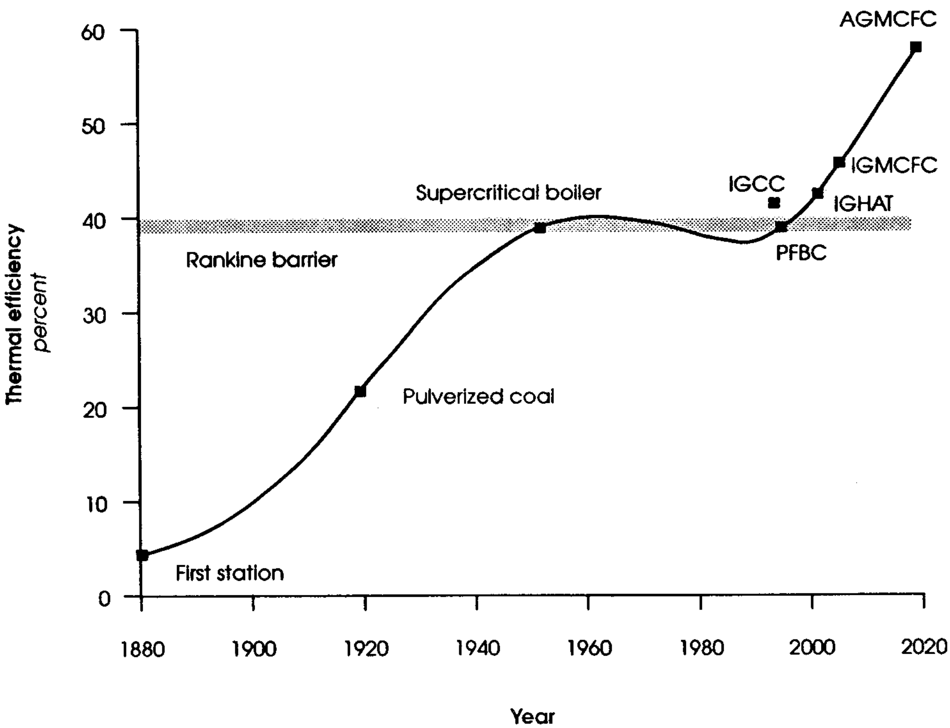
Various land area requirements are listed in table 11, page 39. The 26 million hectares required is a large land area compared to the 5.7 million hectares that is now used for fuelwood plantations. But China is pursuing a reforestation effort that has already led to a 25 percent increase in the amount of forest-covered land over the mid 1960s level and has established a goal of increasing its forest cover by 52 million hectares by 2000 (compared to the mid 1980s) and by an additional 93 million hectares over the longer term.[11] The targeted land area for plantations that would support BIG/GT units is thus half of the land area targeted for reforestation in 2000 and less than one fifth of the land area targeted for reforestation in the long term. Thus, the amount of land needed for electricity production in the long term does not seem unreasonable.

Productivities of the order of 10 dry tonnes per hectare per year and more have been demonstrated experimentally in biomass plantation development efforts in various parts of the world. But, at the present, there is not enough commercial experience to make a judgment as to the feasibility of achieving such average yields on a land area of 26 million hectares in China. However, biomass plantation technology is at an early stage of development, and experience with various food crops cultivated on a large scale suggests that such average yields could be practical in the near term.[38] Moreover, if modern conversion technologies like BIG/GT are used, it will usually be feasible to pay biomass producers high prices as an incentive to generate high yields. This is possible because the high efficiency and low unit capital cost of the technology gives the biomass feedstock a high value.

Thus, while the biomass scenario described here is ambitious, it is not obviously implausible. In light of the greenhouse and other benefits it offers, the BIG/GT option warrants further scrutiny.

While ultimately land and water availability constraints will limit the expansion of biomass production for energy purposes, over time these constraints could be managed both through technological improvements in biomass productivity and conversion technology. Average biomass productivities more than twice those assumed here are targeted for US biomass plantations in the period beyond the turn of the century.[40] The expected continuing improvements in gas turbine technology will lead to efficiencies higher than the 42 percent value assumed for this scenario. Moreover, beyond the turn of the century, electricity could also be provided at even higher efficiencies with fuel cell power systems. The Electric Power Research Institute projects[26] that by the year 2020 coal-integrated gasifier/molten carbonate fuel cells could be providing electricity at efficiencies approaching 60 percent (see figure 6). As in the case of gas turbine technology, much of this technology could be adapted to biomass, with comparable performance. Such possibilities were not taken into account in constructing the scenario.

An evolutionary approach could be taken to the generation of electricity from biomass. Initially, a biomass power industry could be launched in those parts of China where biomass power generation costs are low compared to coal-based power generation, using steam-turbine power-generating units originally designed and produced in China for coal but modified for use with biomass. With this conversion technology a variety of biomass feedstocks could be tested to determine the most promising biomass production strategies in various regions. BIG/GT technology could be introduced subsequently, and its development on a large scale could be undertaken when the domestic manufacturing capability is established.



PFBC: Pressurized fluidized-bed combustion
IGCC: Integrated gasification–combined cycle
IGHAT: Integrated gasification–humid air turbine
IGMCFC: Integrated gasification–molten carbonate fuel cell
AGMCFC: Advanced gasification–molten carbonate fuel cell

Figure 6: *Evolution of the Efficiency of Coal-fired Power Plants*: The efficiency of steam-based (Rankine cycle) power plants increased steadily for 80 years, nearing theoretical limits in the 1960s. Since then, efficiency has decreased somewhat because of the need to use energy to remove pollutants formed during combustion. Breaking the Rankine barrier of practical limitations on efficiency will require innovative approaches based on chemical energy conversion, such as goal gasification, and electricity generation by means of advanced combustion turbines and fuel cell technologies.[26]

CONCLUSION

The electricity scenario presented here suggests that an expansion of the power sector in China consistent with achieving a high living standard could be brought about over the next half century in ways that offer major environmental benefits, including low CO_2 emissions, at competitive cost. While this "decoupling" of pollutant emissions from electricity demand growth requires the introduction of modern energy systems, the scenario described here could be achieved with technologies that are likely to become widely available in the 1990s. With other technologies that are likely to become available after the turn of the century, including such promising renewable technologies as wind power, solar thermal electric power, and photovoltaic power,[27] this decoupling could be achieved even more readily.

The electricity strategy described here may well be economically attractive if the principal practical alternative to the strategy were coal-fired, steam-electric generating technology with *tight controls on emissions of SO_2 and particulates*. Compared to coal plants without pollution controls, the technologies described here are more costly. This underscores the importance of taking a holistic approach to energy planning—identifying and pursuing strategies that will simultaneously satisfy development and a range of environmental objectives, including control of local air pollutants as well as of greenhouse gas emissions.

Despite the auspicious technological and economical prospects for an energy future such as that outlined here, this future could not be realized under "business as usual" conditions. It would require new concerted efforts at both the national and international levels. Policymakers generally should try to find ways to shape environmental policies so as to speed up the rate of technological innovation and thereby promote economic growth. A major challenge for the international community is to find ways for countries to work together to bring about an energy future consistent with sustainable development.

ACKNOWLEDGEMENTS

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Table 1: Low CO_2-emitting scenario for electricity consumption in China

	Electricity consumption TWh_e/year		CO_2 emissions Mt C/year	
	1989[a]	**2039[b]**	**1989**	**2039**
Hydroelectricity	98.1	403[c]	0.0	0.0
Natural gas	–	413[d]	0.0	49.5
Oil	15.3	–	4.2	–
Coal				
Steam-electric plants	369.2	–	128.8	–
Coal gasification with CO_2 sequestered	–	–	–	–29.8[f]
Hydrogen-fueled fuel cells	–	960[e]		
Combined cycles	–	187[e]		
Coal gasification with CO_2 vented			–	113.3[g]
Hydrogen-fueled fuel cells	–	446[h]		
Combined cycles	–	106[h]		
Nuclear	–	80[i]		
Biomass-integrated gasifier/gas turbines	–	495[j]		0.0
Total	**482.5**	**3,090[k]**	133	133

a. From table 4, assuming 15 percent transmission and distribution losses.

b. Assuming 10 percent transmission and distribution losses.

c. Assumed to be double the level of hydroelectricity projected for 2000 by the World Bank (table 4). The exploitable hydropower resources in China are 380 GW_e[1], which, at the 1989 average capacity factor of 39 percent,[1] could provide about three times as much hydroelectricity as this.

d. According to China's national oil and gas resources assessment completed in 1987, total natural gas resources on land and on the continental shelf of China are 33.3 trillion normal m^3 (Nm^3)[1], or about 1,300 exajoules. It is assumed that natural gas production is expanded to a level by 2039 at which gas resources would last 100 years—some 13 exajoules per year. To support this level of production, proved gas reserves would have to increase from the 1989 level of 39.0 exajoules (1 trillion Nm^3) (4) to 130 exajoules, assuming a reserve/production ratio of 10. It is assumed that 25 percent of natural gas production (3.3 exajoules per year) in 2039 is used for electricity generation in gas turbine/steam turbine combined cycles with an efficiency of 50 percent (LHV basis). Thus, gas-based electricity generation would amount to:

$$(3.3 \text{ exajoules})/((0.0036 \text{ exajoules}/TWh_e)/0.50) = 458\ TWh_e.$$

e. It is assumed that coal gasification with CO_2 sequestering is carried out at a level such that the amount of CO_2 recovered each year is equal to what can be sequestered in the natural gas reservoir space that is depleted each year. If the natural gas reservoirs are repressurized to the original reservoir pressure (assumed to be 300 bar), then the amount of carbon that can be sequestered as CO_2 is 1.4 times the amount of carbon originally removed as natural gas.[3] Thus, for a natural gas production rate of 13 exajoules per year, the amount of carbon that can be sequestered is:

$$1.4 \cdot (15 \text{ Mt C/exajoule}) \cdot (13 \text{ exajoules/year}) = 273 \text{ Mt C/year}.$$

Since the amount of CO_2 that must be sequestered per unit of electricity consumed is (table 2, notes a and f)

$$0.88 \cdot (25.5 \text{ Mt C/exajoule})/(94.2\ TWh_e/\text{exajoule}) = 0.238 \text{ Mt C}/TWh_e,$$

the amount of potential electricity consumption from coal with CO_2 sequestering in this scenario is:

$$273/0.238 = 1{,}147\ TWh_e/year,$$

of which 960 TWh_e per year would be provided by fuel cells.

f. The net CO_2 emission rate with sequestering is −0.026 Mt C/TWh_e (table 2), so that CO_2 emissions for this technology in 2039 would be:

$$(-\,0.026\ Mt\ C/TWh_e)\cdot(1{,}147\ TWh_e) = -29.8\ Mt\ C.$$

g. This is the maximum rate of CO_2 emissions from coal gasification systems without CO_2 sequestering that would ensure that total CO_2 emissions from the power sector would not exceed the emissions level of 1989.

h. The amount of electricity that could be produced from fuel cells and combined cycles without sequestering the separated CO_2 is (table 2):

$$(113.3\ Mt\ C)/(0.205\ Mt\ C/TWh_e) = 552\ TWh_e/year,$$

of which 446 TWh per year would be provided by fuel cells.

i. Assumed to be four times the level projected for the year 2000 (table 4).

j. It is assumed that electricity requirements not provided by other sources are provided by biomass-integrated gasifier/gas turbine technologies, for which net CO_2 emissions would be zero, if the biomass were grown sustainably.

k. It has been shown[5] that if cost-effective opportunities for efficient end-use of energy are exploited, it would be feasible to provide a Western European living standard (circa 1975) with only about 20 percent more final energy than is consumed at present in developing countries, though there would have to be a major shift to modern energy carriers; in particular electricity use per capita would have to be about 1,840 kWh_e per year (compared to 439 kWh_e per year in 1989), so that for a Chinese population of 1.68 billion (the population in 2039 if population were to grow at the 2020–2025 rate of 0.63 percent per year from the level of 1.54 billion in 2025, as projected by the World Bank[6]), total electricity consumption would be 3,090 TWh_e.

Table 2: CO_2 emissions for alternative power-generating technologies

	Emissions rate[a] *Mt C/TWh$_e$ delivered*
Typical existing coal plants[b]	0.349
Modern, low-sulfur coal-burning 200 MW$_e$ steam-electric plant with flue gas desulfurization[c]	0.288
Natural gas–fired combined cycles[d]	0.120
Cogenerating phosphoric acid fuel cells fueled with hydrogen from coal plus combined cycle power plants fired with the residual fuel gas from coal, with sequestering of the recovered CO_2[e,f]	– 0.026
Cogenerating phosphoric acid fuel cells fueled with hydrogen from coal plus combined cycle power plants fired with the residual fuel gas from coal, with release of the recovered CO_2 to the atmosphere [e,g]	0.205
Biomass integrated gasifier/gas turbine power plants operated in the power-only mode[h]	0.0

a. Here CO_2 emission rates are assumed to be 25.5 million tonnes (Mt) of carbon (C) per exajoule for coal and 15.0 Mt C per exajoule for natural gas (LHV basis). Transmission and distribution (T&D) losses for the existing power system are assumed to be 15 percent. For central station power systems in the year 2039, it is assumed that T&D losses are 10 percent. T&D losses are assumed to be zero for cogeneration systems.

b. In 1989 the heat rate for power generation (LHV basis) was 11.63 MJ/kWh$_e$ (31.0 percent efficient), see table 3.[1]

c. For a heat rate of 10.18 MJ/kWh$_e$ (35.4 percent efficient), see table 5.

d. For a heat rate of 7.2 MJ/kWh$_e$ (50 percent efficient), see table 6.

e. A hydrogen-rich fuel gas can be produced from coal using commercially ready oxygen-blown coal gasifiers plus other conversion technologies that are commercially available.[3] For each exajoule of coal input, the produced gas consists of 0.57 exajoules of 99.99 percent pure hydrogen that is piped 1,600 kilometers to remote markets for use in fuel cells (that convert 50 percent (30 percent) of the hydrogen fuel energy to electricity (steam)) plus 0.16 exajoules of a residual fuel gas that is used to produce electricity at an efficiency of 50 percent in combined cycle power plants, see tables 6,7, 8, and 9.

f. If the CO_2 separated from the hydrogen and residual fuel gas is piped to and sequestered in depleted natural gas wells, the CO_2 emissions per exajoule of coal input are reduced by 88 percent. Operation of the system requires electricity from the fuel gas–fired combined cycle plants in the amount 2.26 TWh$_e$ to help run the hydrogen-rich fuel gas plants plus 2.82 TWh$_e$ to run the compressors for the hydrogen pipelines, per exajoule of coal input. The residual fuel gas required to produce this electricity amounts to 0.037 exajoules per exajoule of coal input—some 23 percent of the residual fuel gas supply. Thus, the net electricity production per exajoule of coal is 79.0 TWh$_e$ from fuel cells and 16.9 TWh$_e$ from combined cycles burning fuel gas. The net delivered electricity from this system is thus $79.0 + 0.9 \cdot 16.9 = 94.2$ TWh$_e$ per exajoule of coal. The CO_2 emissions per TWh$_e$ of delivered electricity are thus:

$$0.12 \cdot (25.5 \text{ Mt C/exajoule})/(94.2 \text{ TWh}_e\text{/exajoule}) = 0.032 \text{ Mt C/TWh}_e.$$

From this should be subtracted the CO_2 emissions-reduction credit associated with steam cogenerated by the fuel cells. Each TWh$_e$ of electricity produced by fuel cells is associated with 0.6 TWh = 0.00216 exajoules of steam for heating applications. It is assumed that this steam displaces steam that would otherwise have to be produced from coal at 80 percent efficiency. The CO_2 emissions reduction associated with this cogenerated steam per TWh_e of electricity produced by the system is thus:

$$(79.0/94.2)\cdot(25.5 \text{ Mt C/exajoule})\cdot(0.00216 \text{ exajoules}/0.8) = 0.058 \text{ Mt C/TWh}_e.$$

The net CO_2 emissions, per TWh_e delivered by the system, are thus:

$$0.032 - 0.058 = -0.026 \text{ Mt C/TWh}_e.$$

g. If the separated CO_2 is released to the atmosphere, emissions per TWh_e of delivered electricity are reduced relative to conventional central station power generation, due to improvements in the overall system efficiency. In this case the heat recovered from the gasifier can be used to produce 1.66 TWh_e of electricity per exajoule of coal input more than what is required to run the hydrogen-rich fuel gas production facility. Thus, the net electricity needed from the output of the combined cycle plants to run the H_2 compressors for the pipelines is:

$$2.82 - 1.66 = 1.16 \text{ TWh}_e \text{ per exajoule of coal,}$$

requiring 0.0084 exajoules of fuel gas—some 5 percent of the fuel supply for the combined cycle plants. Thus, the net electricity production per exajoule of coal is 79.0 TWh_e from fuel cells and 20.9 TWh_e from the combined cycle plants. The net delivered electricity from this system is thus $79.0 + 0.9\cdot20.9 = 97.8$ TWh_e per exajoule of coal. The CO_2 emissions per TWh_e (delivered) are thus:

$$(25.5 \text{ Mt C/exajoule})/(97.8 \text{ TWh}_e\text{/exajoule}) = 0.261 \text{ Mt C/TWh}_e.$$

From this should be subtracted the CO_2 emissions-reduction credit associated with steam cogenerated by the fuel cells:

$$(79.0/97.8)\cdot(25.5 \text{ Mt C/exajoule})\cdot(0.00216 \text{ exajoules}/0.8) = 0.056 \text{ Mt C/TWh}_e.$$

Net CO_2 emissions, per TWh_e delivered by the system, are thus:

$$0.261 - 0.056 = 0.205 \text{ Mt C/TWh}_e.$$

h. If the biomass is produced sustainably there is no net buildup in CO_2 in the atmosphere, because the CO_2 released in combustion is offset by the CO_2 taken up during photosynthetic production of the biomass.

Table 3: Primary commercial energy use in China in 1989 (EJ/year)

	Total[a]	Power generation[b]
Oil	4.89	0.21
Gas	0.60	–
Coal	21.53	5.05
Hydro	1.34	1.34
Nuclear	–	–
Total	**28.40**	**6.60**

a. Ministry of Energy, People's Republic of China.[1]

b. For power generation by source, as estimated by the World Bank (table 4), and for an average heat rate of 11.63 MJ per kWh_e, as estimated by the Ministry of Energy, People's Republic of China.[1]

Table 4: World Bank projection of future electric power in China[a]

	1989		1999
Installed capacity		*GW_e*	
Hydro	34.8		70.4
Oil-steam	9.0		9.0
Gas	0.0		0.0
Coal	72.4		136.7
Nuclear	0.0		3.9
Total	**116.2**		**220.0**
Electricity generation		*TWh_e/year*	
Hydro	115.4		223.7
Oil-steam	18.0		18.0
Gas	0.0		0.0
Coal	434.3		826.4
Nuclear	0.0		22.0
Total	**567.7**		**1,100.1**
Capital expenditures, 1989–1999		*billion $*	
Generation			
Local		58.7	
Foreign		44.3	
Subtotal		*103.0*	
Transmission			
Local		7.4	
Foreign		3.1	
Subtotal		*10.5*	
Distribution			
Local		19.6	
Foreign		8.4	
Subtotal		*28.0*	
General			
Local		12.5	
Foreign		2.0	
Subtotal		*14.5*	
Total			
Local		98.2	
Foreign		57.9	
Total		**156.0**	

a. World Bank (2).

Table 5: Cost of electricity in northeast China from low-polluting, steam-electric plants[a] fueled with coal from Shanxi Province (cents/kWh_e)

	With high-sulfur coal		With low-sulfur coal	
	200 MW_e	300 MW_e	200 MW_e	300 MW_e
Capital[b,c]	3.33	2.89	2.91	2.53
O&M[a,c]	1.27	1.02	0.95	0.76
Fuel[d,e]	1.61	1.58	1.58	1.55
Busbar cost	**6.21**	**5.49**	**5.44**	**4.84**
Delivered cost[f]				
Generation	6.90	6.10	6.04	5.38
T&D[g]	0.82	0.82	0.82	0.82
Total	**7.72**	**6.92**	**6.86**	**6.20**

a. Coal plant characteristics are for US conditions, with fabric filters for ash recovery and flue gas desulfurization for sulfur removal and with cost and performance as estimated by the Electric Power Research Institute (7).

b. The high-sulfur coal plants (capable of burning Illinois #6 (4 percent sulfur) bituminous coal) are subcritical steam-electric units with wet limestone flue gas desulfurization (FGD). The installed cost is $1,742 per kW_e for a 200 MW_e plant and $1,496 per kW_e for a 300 MW_e plant. The low-sulfur coal plants (capable of burning Western (0.62 percent sulfur) bituminous coal) are subcritical steam-electric units with spray dryer FGD. The installed cost is $1,511 per kilowatt for a 200 MW_e plant and $1,298 per kW_e for a 300 MW_e plant. To these costs are added a capital charge of $102 per kW_e, the generation share of the "general" capital requirements for power generation (see table 4).

c. Assuming a 30 year plant life, a 10 percent discount rate, an insurance rate of 0.5 percent of the initial capital cost per year (capital charge rate = 0.111), and a 70 percent capacity factor.

d. For high-sulfur coal plants the average heat rate is 10.37 MJ per kWh_e at 200 MW_e and 10.21 MJ/kWh_e at 300 MW_e; for low-sulfur coal plants the average heat rate is 10.18 MJ/kWh_e at 200 MW_e and 10.01 MJ/kWh_e at 300 MW_e.

e. According to a 1985 World Bank study (8), the long-run marginal cost of coal in Shanxi Province is 36–44 yuan per tonne. Adding 25 yuan per tonne for transport to the Northeast brings the delivered cost to 61–69 yuan per tonne (early 1984 prices), or 2.44–2.76 yuan per GJ for coal with a heating value of 6 gigacalories = 25 GJ per tonne. The early 1984 official exchange rate was 1 yuan = 0.5 US$, which becomes 0.593 1989 US$. Thus, the cost of coal delivered to the northeast is $1.45–$1.65 per GJ. Here the cost is assumed to be $1.55 per GJ.

f. Assuming 10 percent transmission and distribution losses.

g. The marginal unit capital cost for transmission and distribution (T&D) (including the T&D share of general capital requirements) is $409 per kW_e of installed generating capacity (see table 4). Operation and maintenance costs for T&D are neglected here.

Table 6: Cost of electricity from gas-fired gas turbine/steam turbine combined cycle power plants[a] (cents/kWh_e)

	General	with fuel gas from coal[b]
Capital[a,c]	1.14	1.14
O&M	0.44	0.44
Fuel	$0.72 \cdot P_g$[d]	3.96
Busbar cost	**$1.58 + 0.72 \cdot P_g$**	**5.54**
Delivered cost[e]		
Generation	$1.76 + 0.80 \cdot P_g$	6.16
T&D[f]	0.82	0.82
Total	**$2.58 + 0.80 \cdot P_g$**	**6.98**

a. According to the Electric Power Research Institute[7] the installed capital cost for a 210 MW_e, 50 percent-efficient, combined cycle plant is $531 per kW_e and the operation and maintenance cost (at 70 percent capacity factor) is 0.44 cents per kWh_e.

b. Here it is envisaged that combined cycle plants located at the syngas plants described in table 7 are fueled with the residual fuel gas (costing $5.50 per GJ, including the cost of sequestering CO_2) left after purifying the hydrogen.

c. To the installed capital cost is added an additional capital charge of $102 per kW_e, the generation share of the "general" capital requirements for the utility (see table 4). Assuming a 30 year plant life, a 10 percent discount rate, an insurance rate of 0.5 percent of the initial capital cost per year (capital charge rate = 0.111), and a 70 percent capacity factor.

d. Here P_g is the price of gas, in $ per GJ.

e. Assuming 10 percent transmission and distribution (T&D) losses.

f. The marginal unit capital cost for T&D (including the T&D share of general capital requirements) is $409 per kW_e of installed generating capacity (see table 4). Operation and maintenance costs for T&D are neglected here.

Table 7: Cost estimate for producing hydrogen-rich syngas or hydrogen from coal, using oxygen-blown coal gasification technology[a]

	with sequestering[b]	without sequestering[c]
Capital cost	*million $*	
Basic plant[d]	678	678
Shift reactors[e]	25	25
Carbon dioxide recovery unit[f]	45	45
Carbon dioxide compressor[g]	46	-
300 kilometer carbon dioxide pipeline[h]	117	-
Carbon dioxide injection system[i]	17	-
Total	**927**	**748**
Annualized cost	*million $/year*	
Capital[j]	103.0	83.1
Coal feedstock[k]	44.2	44.2
Purchased electricity[l]	6.7	- 4.9
O&M for basic plant	24.5	24.5
Additional O&M	4.2	4.2
Additional chemicals and catalysts	1.1	1.1
O&M for CO_2 transport and injection	2.8	-
Total	**186.5**	**152.2**
Cost of hydrogen-rich syngas	*$/GJ*	
	5.51	4.51
Cost for purified hydrogen[m]	*$/GJ*	
Fuel gas feedstock	5.51	4.51
Capital	0.23	0.23
Maintenance	0.08	0.08
Total cost of pure hydrogen	**5.82**	**4.82**

a. For a plant that produces from coal a hydrogen-rich gas (87.5 percent H_2, 6.5 percent CO, 1.2 percent CO_2, 3.8 percent N_2, and 1.1 percent Ar) at an output capacity of 1,175 megawatts (LHV basis—92 percent of the heating value is accounted for by hydrogen). Assuming the plant is operated at capacity for 8,000 hours per year, the annual output would be 33.84 million gigajoules per year.[3]

b. In this case the CO_2 removed from the syngas is compressed to 60 bar and transported via pipeline 300 kilometers to abandoned gas wells were it is injected and sequestered.

c. In this case the CO_2 removed from the syngas is vented to the atmosphere.

d. The point of departure for this analysis is a 710 MW_e coal-integrated gasifier/combined cycle (CIG/CC) power plant. The installed cost for this CIG/CC plant would be $1,043 million, based on a unit cost of $1,467 per kW_e, as estimated by the Electric Power Research Institute.[7] The power-generating unit for this CIG/CC consists of a 480 MW_e gas turbine unit plus a 322 MW_e steam turbine bottoming cycle, with 92 MW_e required for internal power needs. The gasifier involved is a Shell oxygen-blown gasifier operated at 24 bar that produces a syngas from coal. The costs include the cost of the oxygen plant and the cost of syngas cleanup. When this basic plant is converted to the production of a hydrogen-rich syngas, the combined cycle, not needed, is replaced by a 112 MW_e steam turbine that would be driven by heat from the gasifier. Elimination of the combined cycle capacity leads to a 35 percent net cost reduction, from $1,043 million to $678 million (corresponding to an avoided cost of $530 per kW_e for the 690 MW_e combined cycle not needed).

e. Two shift reactors are operated in series—the first at 400 °C, the second at 220 °C. After the second shift reactor, 90 percent of the carbon monoxide from the gasifier would be converted to CO_2. Catalysts would be used to obtain sufficiently fast reactions. The energy content of the fuel gas is reduced 9 percent in this step on a LHV basis (but remains virtually unchanged on a HHV basis, because the latent heat of the water vapor is taken into account with the HHV measure).

f. The CO_2 is removed from the shifted gas (at a concentration of 37 percent in the gas, at 24 bar pressure) by passing it countercurrent through a flow of a Selexol, a physical absorber (a 95 percent solution in water of dimethyl ether or polyethylene glycol), in which the CO_2 will dissolve. By this process 98–99 percent of the CO_2 is removed from the shifted gas. The absorbed CO_2 is then released in isolation from the now hydrogen-rich fuel gas and the Selexol is thereby regenerated. Some 18 kWh_e of electricity is required per tonne of CO_2 for operation of the Selexol unit.

g. The CO_2 is compressed to 60 bar for pipeline transport to the gas wells. The electricity requirements are 55.6 kWh_e per tonne of CO_2, for a four-stage intercooled CO_2 compressor.

h. The pipeline capital cost is estimated to be $800 per kilometer per tonne of CO_2 per hour for a CO_2 transmission rate of 487 tonnes per hour.

i. The capital costs are $12 million for a compressor at the wellhead (requiring 1.0 kWh_e per tonne of injected CO_2) and $5 million for new gas well linings.

j. For a 10 percent discount rate, a 30 year plant life, and an insurance charge of 0.5 percent per year, so that the total capital charge rate is 0.111.

k. For a coal-to-hydrogen-rich fuel gas conversion efficiency of 72.8 percent (LHV basis), the coal input rate is 46.48 million gigajoules per year. The cost of coal at the minemouth in Shanxi Province is assumed to be $0.95 per GJ (see table 5, note e).

l. With sequestering of the removed CO_2, the internal electricity requirements amount to 127 MW_e— 92 MW_e for the basic plant operations, 9 MW_e for Selexol pumping, and 26 MW_e for compression of the CO_2 to 60 bar for transfer to the CO_2 pipeline. Some 112 MW_e can be provided by the steam turbine driven by the steam produced in the gasifier. The remaining 15 MW_e of required electricity is assumed to be purchased from the residual fuel gas-fired combined cycle plant for 5.54 cents per kWh_e (see table 6). If the removed CO_2 is instead released to the atmosphere, some 11 MW_e of electricity more than that needed would be generated at the syngas plant. It is assumed that this excess electricity is sold for 5.54 cents per kWh_e.

m. Some 85 percent of the hydrogen can be recovered from the fuel gas as 99.99 percent pure hydrogen using pressure swing adsorption (PSA) technology. The other 15 percent of the hydrogen stays with the residual fuel gas (51.0 percent H_2, 25.3 percent CO, 4.7 percent CO_2, 14.8 percent N_2, and 4.3 percent Ar). Four PSA units costing $14 million each are required here. Maintenance costs amount to 4 percent of the capital cost per year. It is assumed here that the purified hydrogen is transported via pipeline (table 8) to remote markets (table 9) and that the residual fuel gas is burned locally in combined cycle plants (table 6).

Table 8: The estimated cost of long-distance transmission, storage, and distribution of hydrogen (\$/GJ)[a]

Compressor	
Capital[b]	0.044
Operation and maintenance[c]	0.036
Electricity[d]	0.275
Subtotal	*0.355*
Transmission pipeline	
Capital[e]	0.535
Operation and maintenance[f]	0.048
Subtotal	*0.583*
Storage[g]	0.159
Local distribution[h]	0.500
Total transmission and distribution cost	**1.60**

a. For a 1,609 kilometer (1,000 mile) hydrogen pipeline with a capacity of 13.5 gigawatts (LHV basis) and an annual delivery rate of 0.39 exajoules/year (for operation at capacity for 8,000 hours/year)—corresponding to the output of 15 hydrogen-producing plants like those described in table 7. At the pipeline inlet the hydrogen is compressed from 24 to 68 bar (1,000 psia). The hydrogen pressure at the pipeline exit is assumed to be 20 bar, so that the diameter of the pipeline is 1.6 meters.[9]

b. The required compressor capacity is 205 megawatts. The capital cost for the compressor is assumed to be \$680 per kilowatt.[9] For a 10 percent discount rate, a 20 year plant life, and an insurance rate of 0.5 percent of the capital cost per year, the capital charge rate is 0.1225.

c. Assumed to be 10 percent of the initial capital cost per year.[9]

d. For an 85 percent–efficient, two-stage, intercooled compressor, the electricity requirements are 4.96 kWh_e per GJ of hydrogen (1.8 percent of the energy content of the transported hydrogen. The price for the purchased electricity is assumed to be 5.54 cents per kWh_e (see table 6).

e. A 1.6-meter hydrogen pipeline is estimated to cost \$1,168 per meter.[9] Thus, the cost for a 1,609 kilometer pipeline is \$1,879 million. Assuming a 10 percent discount rate, a 30 year pipeline life, an insurance rate of 0.5 percent of the capital cost per year, the total capital charge rate is 0.111.

f. Assumed to be 1 percent of the initial capital cost per year.[9]

g. Storage capacity amounting to one fourth of daily pipeline throughput is assumed to be installed at the end of the transmission line. This capacity would allow for diurnal variations in hydrogen demand—with the average demand in daytime three times the average demand at night. Rock cavern storage is assumed, with the cavern pressure varying from 17 to 26 bar over the storage cycle.[41] For the entire pipeline it is assumed that there are 15 caverns, each able to store 160 tonnes (19,000 gigajoules) of hydrogen. The annualized costs (in \$$10^6$ per year) for all 15 storage units are as follows:

Storage construction, operation, and maintenance	54.6
Cushion gas (2.7 times the gas storage capacity)	0.6
Capital and O&M cost for storage compressor	3.4
Electricity for storage compressor	3.5
Total	**62.1**

h. See reference 9.

Table 9: Busbar electricity cost with phosphoric acid fuel cells operated on hydrogen derived from coal (cents/kWh_e)[a,b]

	with sequestering	without sequestering
Capital[a,b,c]	2.10	2.10
Fuel[d]	5.34	4.62
O&M	0.57	0.57
Steam credit	− 0.66	− 0.66
Total	**7.35**	**6.63**
Total with half steam credit[e]	**7.68**	**6.96**

a. First-generation phosphoric acid fuel cells (first commercial service is expected in 1993[7]) are described by the Electric Power Research Institute[7] to be 43 percent efficient (LHV basis) when operated with a fuel reformer on light distillate fuel oil, with an installed cost of $1,478 per kW_e and an O&M cost (at 60 percent capacity factor) of 0.86 cents per kWh_e (exclusive of the credit for the cogenerated by-product steam, which is valued at 0.73 cents per kilogram) for a 10 MW_e cogenerating unit. Much better performance and lower costs can be expected for fuel cells that operate on hydrogen directly, without the need for a fuel reformer.

b. Since there is presently little commercial interest in fuel cells operated on pure hydrogen, cost and performance data are not well established for hydrogen phosphoric acid fuel cells. However, rough estimates based on considerations of the penalties associated with methane reformers suggest the following: the electrical efficiency would be 50 percent, 30 percent of the fuel energy input can be recovered as steam for process (2.16 MJ per kWh_e, or 0.91 kilograms steam per kWh_e), the installed capital cost is $1,000 per kW_e, and the O&M cost is one third less than for a fuel cell operated on light distillate fuel oil. The hydrogen fuel is assumed to be delivered by a 1,609 kilometer (1,000 mile) pipeline to a site in the northeast of China, from a hydrogen production center in Shanxi Province (see table 8).

c. Assuming a 30 year plant life, a 10 percent discount rate, an insurance rate of 0.5 percent of the initial capital cost per year (capital charge rate = 0.111), and a 60 percent capacity factor. (This capacity factor corresponds to average operation at full capacity in the daytime, one third of capacity at night, and a 90 percent availability.)

d. The delivered hydrogen cost is $7.42 per GJ if the costs of sequestering CO_2 are included and $6.42 per GJ if the sequestering costs are not included (see tables 7 and 8).

e. While the domestic hot water provided by the fuel cells could be used all year round, the space heating demand would be limited to winter. In summer much of the available heat could not be used.

Table 10: Electricity cost for 37 MW_e biomass-integrated gasifier/combined cycle plant[a] (cents/kWh_e)

	Demonstration plant	Commercial plants
Capital[b]	3.17	2.44
O&M[c]	0.41	0.35
Fuel[d]	$0.857 \cdot P_b$	$0.857 \cdot P_b$
Busbar cost	**$3.58 + 0.857 \cdot P_b$**	**$2.79 + 0.857 \cdot P_b$**
Delivered cost[e]		
Generation	$3.98 + 0.952 \cdot P_b$	$3.10 + 0.952 \cdot P_b$
T&D[f]	0.82	0.82
Total	**$4.80 + 0.952 \cdot P_b$**	**$3.92 + 0.952 \cdot P_b$**

a. This biomass-integrated gasifier/gas turbine (BIG/GT) system, designed at the Shell International Petroleum Company.[10] It consists of an Ahlstrom circulating fluidized bed gasifier coupled to a gas turbine/steam turbine combined cycle based on the Rolls Royce RB211 gas turbine.

b. Shell analysts estimated that the installed capital cost would be \$1,600–\$1,700 per kW_e for a demonstration plant and \$1,200–\$1,300 per kW_e for commercial plants. Here the capital cost is assumed to be \$1,650 per kW_e for a demo and \$1,250 per kW_e for commercial plants. To these costs are added a capital charge of \$102 per kW, the generation share of the "general" capital requirements for power generation (see table 4). Here a 30 year plant life, a 10 percent discount rate, an insurance rate of 0.5 percent of the initial capital cost per year (capital charge rate = 0.111), and a 70 percent capacity factor are assumed.

c. The O&M cost estimates are from figure 8, p.10, in reference 10.

d. Here P_b is the delivered biomass fuel price—including the costs of chipping, transport from the production site, and storage.

e. Assuming 10 percent transmission and distribution losses.

f. The marginal unit capital cost for transmission and distribution (including the T&D share of general capital requirements) is \$409 per kW_e of installed generating capacity (see table 4). O&M costs for T&D are neglected here.

Table 11: Land-use implications of the electricity scenario for China presented in table 1

	million ha	
Plantation area required for biomass electricity production scenario[a]	26	
Area in fuelwood plantations as of 1989[b]	5.7	
China's goal for increased forest cover by 2000 (increment over the 1983–85 level)[c]	52	
China's long-term goal for increased forest cover (increment over the 1983–85 level)	145	
Land use patterns in China, 1983–85[d]	*million ha*	*Percent change over 1964–1966*
Cropland	100.9	− 3.4
Permanent pasture	285.7	0.0
Forests and woodland	134.5	+ 24.7
Other	411.5	− 5.3
Total	**932.6**	

a. In the scenario presented in table 1, some 495/0.9 = 550 TWh_e per year of electricity would be produced in 2025 from biomass in 42 percent–efficient biomass-integrated gasifier/gas turbine power plants (see table 10). Thus, some 4.7 exajoules per year or 262 million dry tonnes per year of biomass fuel would be required, assuming a heating value of 18 gigajoules per dry tonne for biomass. Here an average plantation productivity of 10 dry tonnes per ha per year is assumed.

b. Ministry of Energy, People's Republic of China.[1]

c. In the early 1980s China announced its goal to raise its forest cover to 20 percent of its land area by the year 2000, with an eventual goal of 30 percent.[11]

d. Table 16.1 in reference 12.

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