

Toward zero emissions from coal in China

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China depends for most of its energy on coal – a situation that is likely to persist in the light of the abundance of its coal resources, the paucity of its oil and gas resources, and the reluctance of the government to allow China to become overly dependent on energy imports. The challenge is to find ways to use coal without the enormous air pollution damage caused by current conversion technologies and with greatly reduced carbon dioxide (CO₂) emissions. A coal energy system for China is proposed that could ultimately be characterized by near-zero emissions of both air pollutants and greenhouse gases.

The key enabling technology is oxygen-blown (O₂-blown) gasification to generate synthesis gas from coal. This technology is used in commercially ready integrated gasification combined-cycle power plants that can provide electricity with air pollutant emissions as low as emission levels for natural gas combined-cycle plants. O₂-blown gasification is not yet used in China's energy sector, although the technology is well-established in China's chemical process industry.

The key enabling strategy, which would often lead to attractive energy costs without further technological advances, is "polygeneration" – the co-production from synthesis gas of at least electricity and one or more clean synthetic fuels (e.g., dimethyl ether (DME), Fischer-Tropsch (F-T) liquids, hydrogen (H₂)) and often also chemicals, town gas, and/or industrial process heat. The products of polygeneration could be used in the near term to serve a wide range of energy needs with extremely low levels of air pollutant emissions.

In such polygeneration configurations CO₂ can often be produced in relatively pure streams as a co-product as a result of processing to increase the synthetic fuel's hydrogen-to-carbon ratio. In the near term this CO₂ might be used profitably for enhanced oil recovery or enhanced recovery of methane from deep beds of unminable coal where resource recovery opportunities exist.

For the longer term the potential exists for evolving the coal energy system to the co-production primarily of electricity and H₂ for serving urban areas, with most of the carbon in the coal ending up as CO₂ that is sequestered in geological reservoirs such as in depleted oil and natural gas fields and deep saline aquifers at low incremental cost – even where there are no opportunities for using the CO₂ for enhanced resource recovery. The H₂ so produced would be used for fueling zero-polluting fuel-cell vehicles, for distributed cogeneration (combined heat and power) applications in stationary fuel cells, and for cooking and heating applications as well.

A third clean carbon-based synthetic fuel might also be needed for serving rural markets that would be difficult to serve with H₂, unless there are breakthroughs in H₂ storage technology. DME is a strong candidate for becoming the "third" clean energy carrier for China.

Evolving a coal-based energy system that would be characterized ultimately by near-zero emissions of air pollutants and greenhouse gases would probably involve shifting the center of gravity for central-station power generation to the chemical process industries that would ultimately be co-producing as their major products electricity, H₂, and (perhaps) DME. Ongoing structural reforms in the electric power sector that encourage greater competition in power generation would facilitate the realization of this vision for coal.

1. Introduction

As a result of energy market reforms, coal consumption has been declining in China. In 2000, coal consumption was reported to be 29 % less than in 1996, when coal accounted for 76 % of China's primary energy consumption [BP, 2001]^[1].

However, China is still one of the world's leading coal consumers. In 2000, coal accounted for 63 % of primary energy consumption in China – compared to a worldwide average of 25 %. As a percentage of primary energy in

2000 coal consumption was higher only in South Africa (76 %), but China consumed almost 6 times as much coal [BP, 2001]. In 2000 China's coal consumption was 20.3 EJ/year (22 % of the world total), and China was out-ranked in terms of absolute coal consumption only by the United States with 23.7 EJ/year.

Moreover, coal consumption in China is expected to grow significantly in the decades immediately ahead. The US Energy Information Administration projects that China's coal use will increase 2.4-fold, 1999-2020, to 48

EJ/year or 40 % of the world's total [EIA, 2001].

The expectation of substantial growth in coal use as a follow-up to the recent coal market correction reflects the relative scarcity of domestic oil and gas resources in relation to coal, and reluctance on the part of China to become overly dependent on energy imports.

Proved reserves of oil and natural gas in China amount, respectively, to 4.3 and 1.6 years of total primary energy consumption in 2000 [BP, 2001], compared to more than 100 years for coal^[2]. Median estimates made by the US Geological Survey of ultimately recoverable conventional oil and gas resources amount to 12 and 9 years of supply at the 2000 primary energy consumption rate, respectively [Masters et al., 1994], compared to more than 600 years for coal^[3]. Unconventional heavy oil resources might add another 3 years of primary energy supply [Rogner, 2000]. Coal bed methane (CBM) resources in China are substantial, although the fraction of these resources that might eventually be exploited is uncertain, and in any case the energy content of these resources amounts to less than proved reserves of coal^[4].

Coal use in China is accounted for by industrial boilers and furnaces (almost 1/2), power generation (almost 1/3), and heating and cooking in residential and commercial buildings – with power generation dominating coal demand growth at present. In the future coal may well be used to make transport fuels as well, because of rapid growth in transport energy requirements, limitations of domestic oil in meeting these needs, and concerns about growth of oil import dependency.

2. Coal, environment, and public health

Although coal is abundant and cheap, its use typically causes major environmental damage. A recent World Bank study [World Bank, 1997] assessing the costs of local/regional air pollution damage in China estimated total costs to be \$ 48 billion in 1995 (7 % of GDP), including impacts of acid deposition as well as health effects from air pollution. The study found that the dominant cost was associated with the health impacts of both indoor and outdoor air pollution.

Health damage, mainly to women and children, as a result of indoor air pollution in rural areas from cooking with coal and biomass fuels was valued in the study at about \$ 11 billion for 1995, and damage for urban residents was valued at \$ 32 billion (5 % of GDP). Moreover, the Bank projected that under “business-as-usual” conditions (with a 2.7-fold increase in coal consumption, 1995–2020) health damage to urban residents would increase to \$ 98 billion by 2020 at current income levels, or \$ 390 billion (13 % of GDP) with adjustment for expected growth in income. (The estimated health costs increase with income because the World Bank estimated costs on the basis of the principle of “willingness to pay” to avoid adverse health impacts.)

Pollution costs in China are high both because coal is the dominant fossil fuel and because there are relatively low levels of pollution control on coal conversion equipment. However, even in countries where relatively high

levels of polluting emission control are mandated and enforced, health damage costs from coal steam power plants can be high.

Recently, studies [Rabl and Spadaro, 2000; Krewitt et al., 1999] have been carried out for the Externe Programme of the European Commission aimed at quantifying the external social costs of air pollution. These studies found that external social costs are dominated by health impacts and that the costs of health impacts from fine-particle air pollution are especially high. Most fine-particle air pollution is caused by fossil-fuel burning – both direct emissions of fine particles and sulfate and nitrate particles formed in the atmosphere from gaseous emissions of SO₂ and NO_x.

Rabl and Spadaro [2000] have generated both median estimates of costs and geometric standard deviations; for aggregated morbidity and mortality, they found a geometric standard deviation of about 4, so that the 68 % confidence interval for costs is the range 1/4 to 4 times the median cost. Their economic calculations reflect recent epidemiological studies indicating that: (1) serious chronic health effects (especially life-shortening) are strongly correlated with fine particles (PM_{2.5} particles, with diameters less than 2.5 microns) in the air that can penetrate into the deep lungs, and (2) the dose-response functions for health impacts are approximately linear, with no evidence of a threshold [Pope et al., 1995; Wilson and Spengler, 1996].

Although causal factors for the adverse health effects are not well established and there is considerable uncertainty relating to the magnitudes of the health impacts from small-particle air pollution, the economic value of the health impacts is expected to be high in densely populated regions of high-income countries. Results of these environmental damage cost studies are summarized in Table 1 for alternative fossil-fuel power plants that might be built under typical European siting conditions. This table shows that new coal steam-electric plants equipped with best available control technologies (BACT) at typical European sites would have environmental damage costs that are about 2/3 the direct economic costs of producing this electricity (compare Tables 1 and 2). Although health damage costs would typically be much lower today for coal plants equipped with BACT in countries like China with low per capita incomes, incomes in China are rising rapidly, and damage costs will rise much more rapidly than GDP^[5], so such findings are relevant to thinking about China's future.

Climate change is another major environmental concern. Coal is problematic in this regard because it is the most carbon-intensive fossil fuel, because its conversion to useful energy is typically not especially efficient, and because China is so dependent on coal. Average (30%-efficient) coal power plants in China emit more than 3 times as much CO₂ as state-of-the-art natural gas combined-cycle plants. Only marginal gains are feasible by shifting to more efficient coal steam-electric plants: as shown in Table 1, new 37%-efficient coal steam-electric plants release 2.6 times as much CO₂ per kWh generated as combined-

Table 1. Emission rates for and estimated costs of environmental damage from air pollutant emissions of fossil-fuel power plants (valuation for typical European conditions)

Primary air pollutant	Emission rate (g/kWh)			Median estimate of environmental damage costs (€/kWh) ^[1]				Environmental damage costs relative to NGCC
	SO ₂	NO _x	PM ₁₀	SO ₂	NO _x	PM ₁₀	Total	Total
Average US coal steam-electric plant, 1997	6.10 ^[2]	3.47 ^[2]	0.16 ^[3]	6.36	5.56	0.28	12.2	82
New coal steam-electric plant with best available control technology ^[4]	0.46	0.87	0.15 ^[3]	0.48	1.40	0.24	2.12	14
Coal IGCC plant ^[5]	0.075	0.082	0.0025	0.080	0.132	0.004	0.216	1.5
NGCC plant ^[6]	-	0.092	-	-	0.148	-	0.148	1.0

Notes

1. Environmental damage costs from power plant air pollutant emissions are assumed to be 1/4 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 damage 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 (geometric mean) estimates of damage costs (in \$/kg) were \$ 10.44, \$ 16.00, and \$ 17.00, respectively. The probability distribution of damage costs is lognormal, with a geometric standard deviation of 4, so that there is a 68 % probability that the actual cost is in the range 1/4 to 4 times the median estimate.
2. Average emission rates in 1997 for US coal plants, whose average efficiency was 34.7 %
3. In 1990, PM₁₀ emissions from US electric utility coal power plants amounted to 245,000 t [Spengler and Wilson, 1996], when these plants consumed 18.0 EJ of coal [EIA, 1998], so that the PM₁₀ emission rate was 13.61 g/GJ – the assumed emission rate for all steam-electric cases in this table.
4. It is assumed: that the new coal steam-electric plant is 37.3 % efficient; that the sulfur content of the coal is 477 g/GJ (1.08 % sulfur by weight), the average for US coal power plants in 1997 [EIA, 1998]; that SO₂ emissions are reduced 95 %, a commercially feasible rate; that the NO_x emission rate is 90 g/GJ – achievable with advanced low-NO_x burners that will be commercially available shortly.
5. It is assumed: that the coal integrated gasifier combined-cycle (IGCC) plant is 46.5 % efficient, based on use of steam-cooled gas turbines (see Table 2a); that the emission rates equal the measured values for the Buggenum coal IGCC plant (Netherlands): 10.6 and 0.3 g/GJ of coal, for NO_x and particulates, respectively, as well as 99 % sulfur recovery (data presented by Co van Liere, KEMA, at the Gasification Technologies Conference in San Francisco, 17-20 October 1999); and that the sulfur content of coal is 477 g/GJ.
6. It is assumed: that the natural gas combined-cycle (NGCC) plant is 60.0 % efficient, based on use of steam-cooled gas turbines (see Table 2a); that the NO_x emission rate is 9 ppmv (dry volume basis, at 15 % O₂), corresponding to an emission rate of 0.092 g/kWh.

cycle plants (see Table 2).

The US Energy Information Administration [EIA, 2001] projects that between 1999 and 2020, China's CO₂ emissions will increase from 71 % to 150 % of those for Western Europe and from 44 % to 82 % of those for the United States. Yet, on a per capita basis, China's CO₂ emissions in 2020 would be just 2/5 of those for Western Europe and less than 1/5 of those for the United States. Still, if China is to remain heavily dependent on coal for energy, ways must be found to provide useful energy from coal with greatly reduced CO₂ emissions at affordable costs, if the long-term goal of achieving "stabilization of the greenhouse gas concentration in the atmosphere at a level that would prevent dangerous anthropogenic interference with the climate", as set forth in Article 2 of the Framework Convention on Climate Change, is to be realized.

3. A syngas-based energy system for coal in China?

In this paper an energy system for China based on coal is proposed that could evolve so that ultimately this system would be characterized by near-zero emissions of both air pollutants and greenhouse gases. The key enabling technology is O₂-blown gasification – a technology perhaps most widely known as a component of coal integrated gasifier combined-cycle (IGCC) power plants. The coal IGCC is a commercially ready technology, although no IGCC plant has been built in China. However,

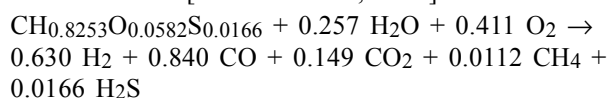
O₂-blown gasification technology is well established in China's chemical process industry: China has in operation, under construction, or on order, 25-30 modern O₂-blown gasifiers; many are for gasifying coal and mostly for ammonia (NH₃) manufacture. Interest in modern O₂-blown gasification technology in China's chemical process industry arises in large part because nitrogen fertilizer demand is growing and much of existing coal-based NH₃ production involves small, inefficient, and polluting plants, many of which are targeted for replacement by larger, cleaner, and more cost-competitive plants.

In the next section, the technology of syngas manufacture is described. This is followed by a discussion of how syngas-based energy systems make it possible to provide energy from coal with extraordinarily low levels of gaseous air pollutant emissions and quite manageable liquid and solid waste disposal problems. The following section discusses how coal-derived syngas can provide clean energy for essentially all sectors of the energy economy. Then polygeneration is proposed for energy production as a strategy for reducing costs of this clean energy to attractive levels without having to wait for major technological advances. The following section shows that a syngas-based energy strategy for coal offers a low-cost approach to climate change mitigation if advanced H₂ production technologies and end-use technologies such as fuel cells enable H₂ to become a major energy carrier complementing electricity in the energy economy in a

greenhouse gas emissions-constrained world – because of the favorable outlook for H₂ energy strategies based on coal and the good prospects for sequestering CO₂ in geological formations at low incremental cost under these conditions. The penultimate section discusses why this syngas-based energy strategy for coal is overwhelmingly preferable to alternative strategies for coal conversion based on advanced conversion technologies in an environmentally-constrained world. Finally, national and international collaborative strategies and policies for fostering this approach to coal utilization in China are discussed.

4. Syngas manufacture

Gasification makes it possible to make use of most of the energy in coal in a convenient gaseous form that has a wide range of potential applications, as will be shown. In coal gasification, coal is reacted with water and an oxidant – air or O₂. In gasification the oxidant is used for partial oxidation rather than complete combustion. As will be clear below, there are great benefits to be exploited if coal is gasified not with air^[6] but with O₂ recovered from air in an air liquefaction plant – typically at 95 % purity^[7]. The product of O₂-blown coal gasification is synthesis gas (henceforth called “syngas”) – a gaseous mixture made up mainly of H₂ and carbon monoxide (CO). For example, when high-sulfur Appalachian bituminous coal^[8] is gasified in the Destec gasifier (an entrained-flow gasifier^[9] operated at a pressure of 25 bar and having a syngas exit temperature of 1040°C), the overall process^[10] can be summarized as [Simbeck et al., 1993]:



The amount of O₂ required for gasification is 1/3 of that required for complete coal combustion (where the major products are water (H₂O) and CO₂^[11] instead of H₂ and CO). Here the heating value^[12] of the produced syngas is 82.5 % of the heating value of the coal from which it is derived. Notably, this so-called “cold gas efficiency” is a *net* efficiency for gasification. Although making the needed O₂ from air is a very electricity-intensive process^[13], this electricity and other energy requirements of the gasification process can be fully provided without burning extra coal, by generating high-pressure steam from heat that is recoverable in the gasification process^[14].

5. Controlling environmental damage with a syngas-based coal energy system

Coal contains many noxious contaminants. Some end up as trace constituents of the syngas generated in gasification – suspended small particles (fly ash), sulfur- and nitrogen-containing gaseous compounds, as well as chlorides and other trace compounds. The rest are recovered in ash removed from the bottom of the gasifier.

Despite the nastiness of the chemical cocktail that is coal, syngas-based coal energy systems can be made as clean as natural gas energy systems without incurring large clean-up cost penalties – as will be shown by con-

sidering management issues relating to gaseous and water effluents and solid wastes.

5.1. Controlling gaseous effluents

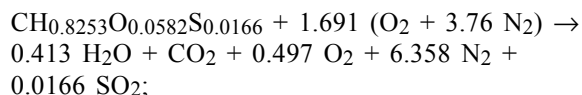
Removing trace gas contaminants from syngas is typically far easier than removing pollutants from stack gases. Consider first fly ash. Entrained-flow gasifiers operate at temperatures higher than the ash fusion temperature. Most of this ash is recovered as a molten slag that flows out of the gasifier through a taphole at the bottom of the gasifier; slagging coal gasification processes produce little or no fly ash. In contrast, fly ash makes up about 80 % of the ash in pulverized coal boilers [Simbeck et al., 1993]. This distinction gives slagging gasification processes a distinct advantage, because fly ash is more difficult to handle, use, and dispose of than slag. Nevertheless, some fly ash containing some unconverted carbon is produced in gasification. In the Destec gasifier, fly ash is recovered in sintered metal filters after some cooling of the syngas exiting the gasifier. This fly ash is recycled back to the gasifier for recovery of the previously unconverted carbon and eventually removed as slag. Any residual particles that escape filtration are recovered in a wet scrubber. Some other gasifiers use cyclones and/or scrubbers for particulate removal.

The scrubber also removes from the syngas chlorides (which could otherwise corrode downstream conversion equipment), NH₃ and hydrogen cyanide (HCN) (trace nitrogen-bearing contaminants that would otherwise form NO_x when the coal syngas is burned), and other potentially harmful trace components [Simbeck et al., 1993].

The sulfur in the coal ends up in the syngas mainly in the form of hydrogen sulfide (H₂S), along with some carbonyl sulfide (COS). Higher levels of sulfur removal are practically achievable when sulfur in these forms is recovered from syngas than is feasible with either flue-gas desulfurization (FGD) or fluidized-bed combustion (FBC) strategies, and the resulting solid waste disposal challenges are typically more manageable (see below).

Note that for the coal gasification example described above (3.2 % sulfur), the H₂S content of the raw synthesis gas is at a concentration of 10,000 ppmv. These sulfur-bearing gases can be effectively and efficiently removed from cooled syngas and converted into elemental sulfur via processes that are well-established in the chemical process industries [Simbeck et al., 1993]. If the syngas is cooled to high ambient temperatures (30-50°C), the sulfur-bearing gas concentrations can be reduced to 10-50 ppmv (more than 99.5 % removal for the example discussed above). Cold gas (sub-ambient temperature) clean-up systems that are somewhat more capital-intensive can reduce sulfur levels to 1 ppmv or less^[15].

Removing sulfur and other pollutants from syngas is typically much easier and less costly than removing pollutants from stack gases because the pollutants are highly concentrated in small volumes, undiluted by the large amounts of N₂ associated with coal combustion in air. If the coal described above were burned in air at atmospheric pressure, the combustion process would be represented by^[16]



the concentration of SO₂ in the stack gases would be only 0.2 %, and its partial pressure would be only 0.002 bar. In contrast the concentration of H₂S in the 25-bar syngas described above is 1.0 % and its partial pressure is 0.25 bar. Thus the volume for sulfur recovery from stack gases is 0.25/0.002 = 125 times as large as that required for recovery from syngas.

5.2. Controlling water effluents

Water used to scrub syngas removes various organic and inorganic compounds – including residual quantities of coal ash. Water purification removes most of the organic compounds; most of the water is typically recycled, and a portion (“blow-down”) is sent to disposal to prevent build-up of salts and other dissolved minerals that come from the coal feed – in the same manner that blow-down is required for water circulating in cooling towers of steam-electric power plants to prevent build-up of salts and minerals. For the Destec gasifier, scrub-water exclusive of blow-down is recycled back to the gasifier. The net process water effluent, usually of higher quality than the blow-down from cooling-towers, is often disposed of with slag [Simbeck et al., 1993].

5.3. Solid waste management

For gasification systems based on entrained-flow gasifiers, the only solids to be disposed of are ash recovered as slag from the gasifier and elemental sulfur recovered from the H₂S and COS in the syngas (see above). These facts imply an enormous solid waste management advantage for gasification systems relative to direct combustion systems.

As noted above, nearly all the coal ash is recovered as a molten slag at the bottom of the gasifier, where it flows into a water-quench bath and is typically crushed and removed as a slag/water slurry. If slag is to be disposed of as a waste material (e.g., in a land-fill), a concern is that trace contaminants (e.g., arsenic, barium, cadmium, chromium, lead, mercury, selenium, silver) not be leached into groundwater. However, long-term leaching tests on coal gasification slag indicate that slag is essentially non-leachable [Thompson et al., 1989]. If the slag is disposed of as solid waste, it is common practice to add 20-30 % water by weight to the solid waste for dust control and optimum bulk density – often blow-down from the syngas scrubber (see above), which contains small amounts of salts and minerals recovered from the scrubbed syngas.

Because slag is essentially inert, it might be feasible to use it for commercial purposes – e.g., as a synthetic aggregate for use in road construction and concrete and cement [Simbeck et al., 1993].

Elemental sulfur is recovered using commercial processes for recovery of sulfurous gases from syngas (see above). Initially this sulfur can be sold profitably in sulfur markets. In the United States about 80 % of the 11 million tonnes (Mt) of sulfur consumed annually is converted to sulfuric acid for use in manufacturing phosphate fertilizer – the demand for which is expected to grow as world

food demand increases. However, it is reasonable to expect that eventually the world market for sulfur would saturate and the sulfur price would collapse if sulfur recovery from clean-up of sulfurous fossil fuel-derived gases were to become commonplace. Under such conditions sulfur would have to be disposed of as a solid waste. However, disposing of sulfur as a solid waste would be far easier and would require dealing with much less bulk material than disposing of wastes associated with FGD or FBC^[17].

6. Opportunities for providing clean energy via coal-derived syngas

Converting coal to syngas makes it possible to provide clean energy from coal for a wide range of potential applications – often at higher efficiency and lower cost than by cleaning up conventional conversion technologies with complicated “end-of-pipe” emission control technologies. The possibilities are illustrated by considering in turn: direct use of town gas for cooking and heating; central-station power generation via IGCC; large-scale IGCC-based cogeneration; distributed, town gas-based cogeneration; and the production of clean synthetic fluid fuels.

6.1. Syngas as town gas for direct fuel applications

Although most potential applications of syngas involve its conversion to other energy carriers for use by final consumers, syngas can also be used directly – e.g., for cooking and heating. In China direct use of coal by urban households accounted for 75 % of residential energy consumption and 9 % of total coal consumption in 1993; 3/4 of urban households use coal for cooking and heating using individual coal stoves [Fang et al., 1998]. These are perhaps the most environmentally damaging coal-using activities in China.

Direct use of coal for cooking and space-heating in urban residences might be replaced by syngas piped as “town gas” to individual residences from a central coal conversion facility. If this were done, the use of primary coal for these applications would be reduced by 1/4 and nearly 1/5, respectively^[18], while particulate and sulfur emissions would be reduced to near-zero, and NO_x emissions would be reduced 80-85 %^[19].

Using coal-derived gas for such purposes is not a novel idea – neither globally nor in China. Coal gas was widely used for more than a century in Western countries before natural gas became readily available. And as of 1988 China’s total coal gas consumption was 19 billion Nm³ (Gm³), 9 % of which was used by urban residents [Fang et al., 1998]. But most technology in use involves providing coal gas without pollution controls. The “new” idea is that extremely clean town gas can be provided using modern coal gasification technology together with modern gas clean-up technologies that are well established in the chemical process industries. Moreover, in the next major section a polygeneration strategy is outlined showing how clean town gas might be provided in the near term at attractive fuel prices.

6.2. Syngas for central-station power generation

Consider next central-station power generation – the ac-

tivity that dominates coal use throughout the industrialized world and is the most rapidly growing coal-using activity in China. O₂-blown gasification technology makes it possible to extend to coal, via IGCC power generating technology, the economic, thermodynamic, and environmental benefits of combined-cycle power generating technology, which has become the technology of choice for thermal power generation throughout the world wherever natural gas is readily available.

Since demonstration of IGCC technology with the 94-MW_e Coolwater Project in Southern California (1984–89), there has been much progress relating to its commercialisation. Table 3 lists 5 large commercial-scale coal IGCC plants around the world that produce electricity or electricity and steam (cogeneration), as well as 9 other large commercial projects that involve gasification of petroleum residues to co-produce electricity with H₂, syngas, or steam^[20]. If all the syngas capacity in these 14 plants (9,163 MW_{th}) were dedicated to power generation, the equivalent electric generating capacity would be about 5,500 MW_e.

Table 1 shows that environmental damage costs associated with measured emissions at the Buggenum coal IGCC plant in the Netherlands are less than 2 % of damage costs for average coal-fired power plants in the United States, about 10 % of damage costs for coal steam-electric plants equipped with best available control technologies, and comparable to damage costs for natural gas combined cycles (NGCCs).

For US-built plants, the electricity cost for IGCC systems currently sold is somewhat higher than for coal steam-electric plants (compare Frame 7F IGCC and steam-electric plant costs in Table 2a) when credit is not taken for environmental benefits (which would probably tip the balance decisively in favour of IGCC – see Table 1). New turbine technology just now coming into the market, based on use of steam-cooled turbine blades (Frame 7H technology), could tip the balance slightly in favour of IGCC even without environmental credits (see Table 2a). However, a shift from steam-electric to IGCC technology would be motivated to a large extent by the cost-effectiveness of the latter in achieving extraordinarily low levels of air pollutant emissions.

IGCC technology also offers a much less costly route for achieving, via fossil fuel decarbonization and CO₂ sequestration in geological reservoirs (see Section 9), deep reductions in CO₂ emissions from coal-fired power plants than is feasible with coal steam-electric plants. The lower cost arises because with gasification the CO₂ can be removed before combustion at much higher CO₂ partial pressures and thus much lower cost than is feasible with coal steam-electric plants, where CO₂ must be recovered from stack gases at very low partial pressures after combustion (see Box 1).

Table 2b shows how the cost of electricity in China with imported IGCC technology would compare with the cost of electricity from domestically produced coal steam-electric plants having alternative levels of pollution control. This table shows that the imported IGCC systems

are much more capital-intensive than the domestic coal plants but that the levelized lifecycle generation cost for the IGCC plant with steam-cooled turbine blades would be less than the generation cost for domestically manufactured coal steam plants equipped with flue gas desulfurization technology – although lifecycle cost savings would be modest.

If China were to adopt coal IGCC technology, it would probably seek to maximize opportunities for domestic manufacture rather than import turnkey plants. Doing so should lead to reductions in capital cost relative to imported technology. Stoll and Todd [1996] estimate that because of local labor and material cost advantages, an IGCC plant built in China would have an installed cost 30 % less than for a plant built in the United States – an estimate that is consistent with the ratio of installed capital costs for coal steam-electric plants with FGD built in China and the United States (compare costs for steam-electric plants in Tables 2a and 2b). Yang carried out a detailed analysis of an IGCC plant designed for construction in the United States and concluded that if opportunities for Chinese manufacture of components were maximized, the installed cost in China would be 47 %–56 % of the cost in the United States [Yang, 1995]. Experience is needed to find out actual realizable savings with efforts to maximize Chinese content of IGCC plants. Also, it may be necessary to build several IGCC plants before realizing significant advantage from local manufacture. Economic benefits of IGCC technology could probably be realized sooner if the technology were deployed initially, not in stand-alone power plant applications, but in applications involving the cogeneration of steam and electricity (see next sub-section) or in polygeneration applications (see next section).

6.3. Syngas for cogeneration at large industrial plants

O₂-blown coal gasification probably has a better chance of being launched in the market via applications other than power-only – for example, in cogeneration where heat for industrial process use is provided as a co-product of electricity. Table 4a illustrates the advantages offered by syngas- (IGCC-) based cogeneration. For this system, fuel requirements are reduced 1/5 and the net electricity generation cost is reduced 1/4 relative to electricity and steam production in separate facilities. Of course, cogeneration strategies can also be pursued with conventional steam turbine technology. However, as illustrated by the calculation in Table 4b for the same levels of electricity and process steam generation as in the IGCC case^[21], the fuel savings rate (5 %) and the reduction in the net cost of electricity (9 %) are far less than for the IGCC case. Moreover, a comparison of Tables 4a and 4b shows that although there is little difference in efficiency and cost for IGCC and ultra-supercritical steam turbine technologies in producing electricity only, IGCC technology is a markedly better performer in cogeneration applications.

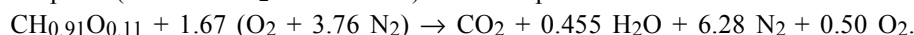
Large industrial firms in China's rapidly growing basic materials processing industries (e.g., basic chemicals, petroleum refining), which tend to have high process heat demands, represent attractive markets for IGCC cogenera-

Box 1. Decarbonization/sequestration costs for alternative coal power-generating technologies

The cost of fuel decarbonization plus CO₂ disposal in a geological reservoir is made up of costs for:

- separating out a relatively pure stream of CO₂ from the fossil energy system;
- compressing CO₂ to a dense (supercritical) state for pipeline transport to the disposal site;
- the CO₂ pipeline and associated rights of way; and
- the wells for injecting the CO₂ into disposal reservoirs and associated surface facilities.

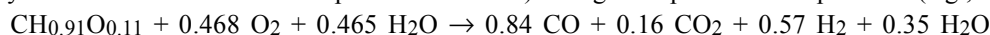
Most decarbonization studies have focused on recovering CO₂ from stack gases of fossil-fuel power plants. Costs for separation and disposal are dominated by the cost of separating out the CO₂ from flue gases – which is high because the CO₂ concentration is low. To see this, note that coal combustion in air for a steam-electric power plant (with 6 % O₂ in the stack) can be represented as:



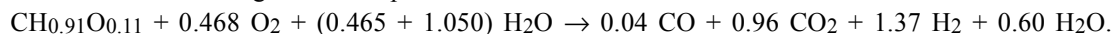
For this system the CO₂ makes up 12 % of the stack gas, and the CO₂ partial pressure is 0.12 bar. At such low CO₂ partial pressure, CO₂ is typically absorbed by reacting with amines (chemical solvents) to form a weakly-bonded intermediate compound that is heated to recover the CO₂ stream and regenerate the original solvent. If CO₂ were recovered from flue gases of a supercritical steam plant, the generation cost would be 60 % (2.0 ¢/kWh) higher than the cost (3.3 ¢/kWh) without CO₂ recovery (for US conditions – see Table 8.9 in [Williams, 2000]).

The concentration of CO₂ in the stack gases can be increased by burning coal in O₂ instead of air and recycling CO₂ back to the combustor – thereby greatly increasing the CO₂ partial pressure. But this approach requires a large and costly air separation plant for O₂ manufacture, so that the cost penalty for CO₂ removal is not reduced (for US conditions – see Table 8.9 in [Williams, 2000]).

An inherently superior approach to CO₂ removal in power generation involves removing the CO₂ not from “flue gases” of a steam-electric plant but instead from the H₂-rich “fuel gas” of a coal IGCC plant (see, for example, Chiesa and Consonni [1998] and Table 5). The process begins with O₂-blown gasification (requiring only 1/3 as much O₂ as for complete combustion) at high temperature and pressure (e.g., 1330°C and 60 bar):



The syngas so produced is cooled to about 350°C and reacted with steam in a pair of water-gas-shift (WGS) reactors^[31]. The sum of gasification plus WGS reactions can be written as:



The shifted syngas is then cooled to 25°C and cleaned of impurities, the H₂O is condensed out, and the syngas is sent to a CO₂ separation unit – where the CO₂ at 40 % concentration and 20-bar partial pressure is recovered and made ready for disposal. (At such high partial pressures, a physical solvent such as Selexol (dimethyl ether or polyethylene glycol) is used for CO₂ removal, for which costs are less than with amines.) The H₂-rich syngas is then burned in a combined-cycle power plant. With near-commercial technology the cost penalty for CO₂ separation and disposal is less than 1 ¢/kWh – see Table 5.

tion technologies.

Cogeneration technologies such as gas turbines, combined cycles, and reciprocating engines that are characterized by high electricity-to-heat output ratios tend to offer much better economic performance than steam turbines, which have low characteristic electricity/heat output ratios (see Figure 1). When such technologies are sized to satisfy the on-site heat demand (often the most attractive configuration) they typically produce more electricity than can be consumed on site. A public policy that makes competitive electricity prices available to these producers for the electricity they wish to sell into electric grids is key to unlocking the cogeneration potential offered by IGCC and other high electricity-to-heat ratio technologies [Williams, 1978].

6.4. Syngas as town gas for distributed cogeneration

The IGCC cogeneration systems described above are suitable for very large plants that produce steam at rates ~400 MW_{th} or more than 600 tph (tonnes of steam/hour). There are some sites in China that could host such large facilities. But typical coal-fired industrial boilers in China are

much smaller. In 1990 medium- and small-scale boilers (defined as producing less than 65 tph) consumed over 350 Mt of coal (35 % of total coal use). There are about 500,000 industrial boilers in China, over half of which have capacities in the range 1 to 4 tph; the average boiler capacity is 2.3 tph or 1.5 MW_{th} [GEF, 1996].

Many of the heat loads now served by such small boilers in small factories, commercial buildings, and apartment buildings would be good candidates for clean, town gas-based cogeneration technologies having power output capacities at scales ranging from less than 100 kW_e to a few MW. As in the case of coal-derived town gas targeting cooking and heating markets discussed above, the basic idea would be to pipe syngas produced from coal in large centralized facilities to distributed cogeneration facilities that might be located up to 30 km from the syngas production facility. Both reciprocating engines and micro-turbines show promise as near-term technologies for town gas-based cogeneration at such scales and are discussed here. In the future fuel cells offer promise for such distributed cogeneration applications; these are discussed be-

Table 2a. Performance, generation costs, and CO₂ emission rates for alternative fossil fuel power plants – for construction in the United States

Performance, costs, emission rates ^[1]	Pulverized coal steam-electric plant w/FGD	Coal IGCC plant		Natural gas combined cycle (NGCC) plant	
		Air-cooled turbine	Steam-cooled turbine	Air-cooled turbine	Steam-cooled turbine
Plant capacity (MW _e)	500	500	400	506	400
Efficiency (% LHV basis)	37.3	42.5	46.5	55.8	60.0
Installed capital cost (\$/kW _e)	1090	1320	1091	468	445
Generation cost elements (¢/kWh)					
Capital charges ^[2]	1.79	2.17	1.79	0.77	0.73
Fixed O&M	0.23	0.28	0.30	0.23	0.23
Variable O&M	0.20	0.20	0.21	0.15	0.15
Fuel ^[3]	0.99	0.87	0.80	2.22	2.06
Total generation cost (¢/kWh)	3.21	3.52	3.10	3.37	3.17
CO ₂ emission rate (gC/kWh) ^[4]	238	210	193	98	91

Notes

1. Plant capacities, installed capital costs, operation and maintenance costs, and plant efficiencies are for construction in the United States, from Todd and Stoll [1997]. Combined-cycle plants (both natural gas combined-cycle (CC) and coal integrated gasifier combined-cycle (IGCC)) 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.
2. Capital charges are for an 80 % average capacity factor, a 10 % discount rate, a 25-year plant life, and an insurance rate of 0.5 %/yr, so that the annual capital charge rate is 11.5 %.
3. Coal and natural gas prices of \$ 1.03/GJ and \$ 3.44/GJ, respectively, the levelized average prices projected for electric generators in the United States for 2005-2030, assuming that prices evolve, 2005-2030, at the projected rates of -0.95 %/y for coal and +1.48 %/y for natural gas, as projected by the US Energy Information Administration, from their projected 2005 price levels of \$ 1.11/GJ for coal and \$ 3.03/GJ for natural gas [EIA, 2000].
4. The carbon content of coal and natural gas are assumed to be 24.3 kg/GJ and 15.2 kg/GJ, respectively.

low in the section dealing with H₂ technologies.

6.5. Cogeneration using reciprocating engines

From June 1997 through May 1998, world-wide sales of reciprocating engines for stationary power markets totalled about 5,100 units (9.6 GW_e of total capacity) – a five-fold gain from 10 years earlier [Wadman, 1998]. Although most units use oil, 13 % use natural gas or will be capable of using dual fuels.

Reciprocating engines can be used for cogeneration by recovering both high-quality heat from engine exhaust and low-quality heat from engine jacket-cooling water. Like gas turbines and combined cycles, reciprocating engines are attractive for such applications because of their high electricity-to-heat output ratios (see Figure 1). Such systems designed to satisfy the on-site heat load often produce more electricity than is needed on-site, so that the key to economic success is often being able to sell excess power into the electric grid at competitive electricity prices.

For spark-ignited engines, operation on natural gas or town 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 % of system fuel requirements for larger

engines. Such engine generator sets are commercially available at scales of 1-16 MW_e with efficiencies of 39-42 %.

Air pollutant emissions, especially NO_x, are a concern. Most lean-burning, spark-ignited natural gas engines and micro-liquid-spark, dual-fuel engines can achieve NO_x emission of 1.4 g/kWh (100 ppmv at 15 % O₂), which is comparable to the emission rate for central-station coal steam-electric plants equipped with NO_x emission controls but 15-20 times the emission rate for coal IGCC plants (see Table 2b). Some vendors now offer systems with half this level of emissions but at an energy efficiency penalty of about 1 percentage point. Air emission concerns with town gas firing 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.

6.6. Cogeneration using microturbines

The microturbine is a gas turbine just entering the market for applications at scales in the range 25 to 500 kW_e. The system involves a low-pressure ratio (3 to 4) gas turbine and compressor mounted on a single shaft^[22]. The most promising models have variable speed generators (the output of which is rectified and converted electronically to the AC line frequency), no gear-box, air bearings and thus no need for the lubricating oil that traditional bearings would require, and only one moving part. Turbine blades are not cooled, turbine inlet temperatures are modest (840°C), but engine speeds are high – 80,000 rpm or more. Conversion efficiencies with natural gas-fuelling are 25 %

Table 2b. Technical, economic, and environmental performance of alternative coal power plants in China

	Coal steam-electric plants built in China ^[1] (alternative levels of air pollution controls)				Coal IGCC plants ^[5] (imported technology)	
	Only ESP	ESP + dry FGD	ESP + wet FGD	ESP + wet FGD + NO _x controls	Air-cooled turbine	Steam-cooled turbine
Plant capacity (MW _e)	300	300	300	300	500	400
Efficiency, LHV basis (%)	34.0	33.0	33.0	33.0	42.5	46.5
Installed capital cost (\$/kW _e)	600	709	764	788	1320	1091
Levelized generation cost elements (¢/kWh)						
Capital charges ^[2]	0.99	1.16	1.26	1.29	2.17	1.79
Fixed O&M	0.26	0.34	0.41	0.41	0.28	0.30
Variable O&M	0.40	0.50	0.50	0.50	0.20	0.21
Fuel ^[3]	1.16	1.20	1.20	1.20	0.95	0.87
Total levelized generation cost (¢/kWh)	2.81	3.20	3.37	3.40	3.60	3.17
SO ₂ emission rate (g/kWh)	10.9	4.5	1.1	1.1	0.082	0.075
NO _x emission rate (g/kWh)	3.0	3.0	3.0	1.2	0.089	0.082
PM ₁₀ emission rate (g/kWh)	0.14	0.15	0.15	0.15	0.0027	0.0025
Relative air pollution damage cost ^[4] (IGCC with steam-cooled turbine = 1.00)	77	46	29	16	1.1	1.0
Relative CO ₂ emission rate (IGCC with steam-cooled turbine = 1.00)	1.37	1.41	1.41	1.41	1.09	1.00

Notes

1. Technical, economic, and environmental performance are from Wu et al. [2001], except that the PM₁₀ emission rate is assumed to be 13.61 g/GJ – see Note 3, Table 1.
2. Calculated according to the procedure outlined in Note 2, Table 2a.
3. The assumed coal price is \$ 1.12/GJ, the levelized average price for electric generators in China for 2005-2030, assuming that the coal price increases 0.5 %/yr, 2005-2030, from its 2005 price level of \$ 1.07/GJ, as projected in Wu et al. [2001].
4. It is assumed that the value of air pollution damage per kg for SO₂, NO_x, and PM₁₀ are in the ratio 1.00:1.53:1.63 – the same as for typical European power plant sitings, as presented in Note 1, Table 1.
5. From Table 2a and Table 1.

at full power output – far less than for large reciprocating engines but comparable to reciprocating engine-generator set efficiencies at scales of tens of kW_e. Efficiency falls off at part load – to 75 % 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, promoters project that it will do well in emerging highly competitive distributed power markets [Craig, 1997]. 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°C) turbine exhaust gas; and the possibility of low NO_x emission levels without stack gas controls^[23].

7. Clean synthetic fluid fuels from coal

Rapid growth in demand for and import of oil in China (see Box 2) plus energy supply insecurity concerns about becoming overly dependent on energy imports suggest that attention be given to making synthetic fluid fuels

from China's abundant coal resources – especially fuels for transportation and cooking that will be compatible with growing environmental concerns.

China is well positioned to become a world leader in producing clean synthetic fuels from coal. Per capita use of oil for transportation in China is 4 % of the industrialized-country average and 18 % of the world average [EIA, 2001]. Its low dependence on oil and correspondingly low level of oil-based transportation infrastructure development combined with rapid demand growth for transportation services make China a good candidate country for evolving relatively quickly a transportation system compatible with the environmental demands of the 21st century.

Synthetic fuel manufacture from coal via syngas offers good prospects for addressing air pollution and climate change concerns. And if synthetic fuels are produced via polygeneration strategies, as discussed in the next section, there are also good prospects that coal-derived synfuels can be provided at attractive costs.

What synthetic fuels should be emphasized? Methanol (MeOH), dimethyl ether (DME), synthetic middle distillates (SMD) produced via the Fischer-Tropsch (F-T) proc-

Table 3. Large commercial gasification projects with electricity as product or co-product

Location	Plant owner	Technology	Syngas out (MW _{th})	Feedstock(s)	Product(s)	Start-up year
Spain	Repsol and Iberola	Texaco	1,543	Vacuum residues	Electricity	2004
Italy	SARLUX srl	Texaco	995	Visbreaker residues	Electricity, H ₂	2000
Italy	ISAB Energy	Texaco	916	ROSE asphalt	Electricity, H ₂	1999
France	Total France, EDF, and Texaco	Texaco	835	Fuel oil	Electricity, H ₂	2003
Netherlands	Shell Nederland Raffinaderij BV	Shell	594	Visbreaker residues	Electricity, H ₂	1997
Czech Republic	SUV and EGT	Lurgi Dry Ash	593	Coal	Electricity, steam	1996
United States	Public Service of Indiana	Destec	551	Bituminous Coal	Electricity	1995
Spain	Elcogas SA	PRENFLO	548	Coal, petcoke	Electricity	1997
United States	Motiva Enterprises LLC	Texaco	520	Fluid petcoke	Electricity, steam	1999
Italy	API Raffineria di Ancona S.p.A.	Texaco	463	Visbreaker residues	Electricity	1999
Netherlands	Demkolec BV	Shell	435	Bituminous Coal	Electricity	1994
United States	Tampa Electric Company	Texaco	424	Coal	Electricity	1996
United States	Exxon USA Inc.	Texaco	407	Petcoke	Electricity, syngas	2000
Singapore	Esso Singapore Pty. Ltd.	Texaco	339	Residual oil	Electricity, H ₂	2000

Source: Simbeck and Johnson [1999].

ess, and hydrogen (H₂) are all examples of clean synthetic fuels that can be derived from coal via syngas. Here emphasis is given to H₂ and DME as leading candidate energy carriers that offer good prospects for addressing environmental challenges. The outlooks for MeOH and SMDs are briefly summarized in Boxes 3 and 4.

7.1. Using and making hydrogen manufactured from coal-derived syngas

Dealing effectively with both climate change and air pollution challenges without abandoning coal and other fossil fuels requires that H₂ be introduced as a major energy carrier [Williams, 1998; 2000].

The climate-change mitigation attractions of H₂ are that, by converting a fossil fuel to H₂: (1) much of the chemical energy in coal can be recovered without releasing CO₂ to the atmosphere if the CO₂ co-product of H₂ manufacture^[25] is stored – e.g., in deep geological formations (see Section 10, “Outlook for disposal of CO₂”, below), and (2) the cost penalty associated with disposal of the CO₂ co-product of H₂ manufacture is relatively modest.

Considerations of health damage costs from automotive air pollution also provide compelling motivation for evolving to automotive fuel and engine technologies characterized by zero or near-zero pollutant emissions. Studies carried out under the ExternE Programme show that health damage costs associated with operating gasoline and diesel cars in Europe are comparable to or greater than direct fuel costs [Williams, 2000] – similar to the situation presented in Table 1 for steam-electric power plants. Recent analyses extending the ExternE findings to urban areas of the United States show that even for advanced liquid-fueled internal combustion engine vehicles (ICEVs) equipped with high levels of pollution controls, health

damage costs would still be comparable to direct fuel costs [Ogden et al., 2001]. Such high levels of damage costs from air pollution are what China could look forward to if it were to retrace the path of Western countries in expanding its road transportation system.

The goal of zero emissions in transportation could be satisfied if H₂ fuel cell vehicles (FCVs) could be brought into widespread use, because H₂, the natural fuel for fuel cells, generates only water as a by-product of energy conversion. Although H₂ is often perceived as a dangerous fuel, it can be used safely if procedures are developed that respect its physical and chemical properties (see Box 4).

Fuel cell technology is approaching commercial readiness for both mobile [Ogden et al., 2001] and stationary power and cogeneration applications [Kreutz and Ogden, 2000]. Fuel-cell buses will soon be commercialized in various countries, and a race is under way among all the world’s major auto-makers to commercialize fuel-cell cars.

H₂ is the preferred energy carrier for FCVs. Compressed gaseous storage is the only technically viable on-board H₂ storage technology at present, which poses a challenge because compressed gaseous H₂ storage systems have only 1/10 the volumetric storage density of gasoline. But fuel-cell cars can be made much more fuel-efficient than today’s typical ICE cars [Ogden et al., 1998; 1999], and fuel-efficient cars can be designed to provide adequate range between refuelings without compromising passenger or trunk (storage) space^[28].

Because a H₂ supply infrastructure for transportation is not in place anywhere in the world, some auto-makers and their suppliers are pursuing market-launching FCV-fueling strategies based on MeOH and gasoline as energy-

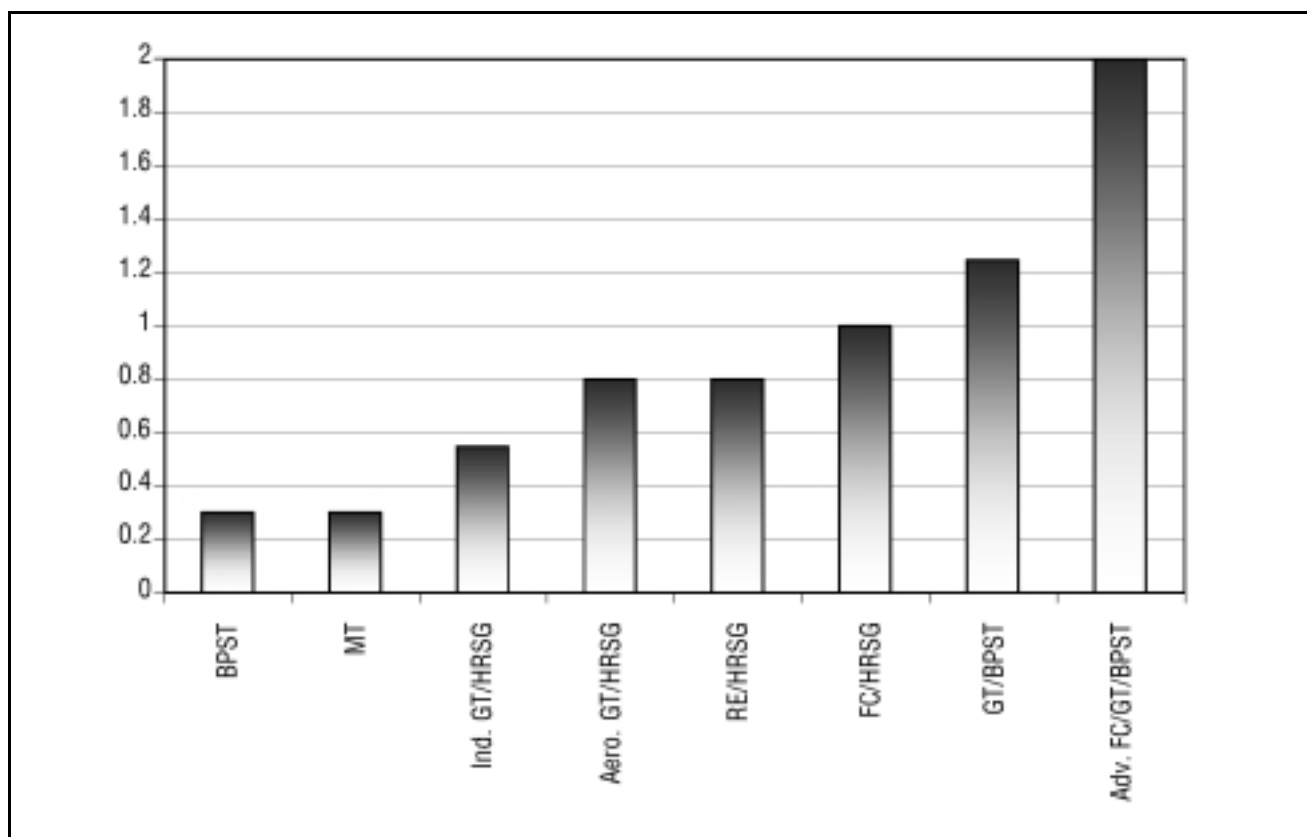


Figure 1. Output ratios of power (kW_e) to heat (kW_{th}) for alternative cogeneration technologies.

The figures are for systems producing 10 bar steam. All steam turbines are back-pressure steam turbines with no steam condenser. BPST = back-pressure steam turbine; MT = micro-turbine; Ind. GT = industrial gas turbine; HRSG = heat recovery steam generator; Aero. GT = aeroderivative gas turbine; RE = reciprocating engine; FC = fuel cell; Adv. FC = advanced fuel cell.

Source: Simbeck [1999].

carriers delivered to the car^[29] – despite the fact that H₂ FCVs would be less costly to own and operate than either MeOH or gasoline FCVs [Ogden et al., 1998; 1999; 2001].

Currently, fuel-cell cars are much more expensive than today's cars. However, inherent materials and fabrication costs are not high for the currently favored proton exchange membrane (PEM) fuel cell, for which large reductions in cost are expected as a result of production at large scales and learning-by-doing (experience) effects, as well as continuing incremental technological improvements. Ogden et al. [2001] estimate that with manufacture in large factories (300,000 vehicles/year), costs for H₂ PEM fuel-cell cars could fall to market-clearing levels^[30] by the time 1-2 million fuel-cell cars have been produced – sometime near the middle of the next decade. They argue that the build-up of cumulative production to the levels needed to “buy down” the technology cost should be carried out in centrally-refueled fleet markets with H₂ fueling – avoiding altogether the more technically challenging and more costly market-launching based on MeOH or gasoline FCVs.

H₂ production technology is well established worldwide for applications in the chemical process and petroleum refinery industries. Where natural gas is readily available, it tends to be the preferred feedstock for H₂ manufacture. Because its natural gas resources are scant, China is one

of the few countries where modern coal gasification technologies are instead used to make H₂, mostly as an intermediate product in NH₃ manufacture.

The manufacture of H₂ from coal using commercial or near-commercial technology is essentially the same as the process described in Box 1 for decarbonization of coal for IGCC power applications – except that at the final stage following CO₂ removal, the H₂-rich gas is purified (up to 99.999 % purity) in a pressure swing adsorption (PSA) unit instead of burned in a combined-cycle power plant.

Making H₂ from coal is more capital-intensive than making H₂ from natural gas, but coal is typically a less costly feedstock. With current natural gas and coal prices in the United States, H₂ derived from natural gas is less costly than H₂ from coal, but natural gas prices are expected to rise slowly and coal prices are expected to fall slowly, so that by 2020 coal-based H₂ is likely to be less costly, based on near-commercial technology [Williams, 2001].

Table 5 presents performance and cost estimates (assuming an appropriate Chinese coal price) for gasification-based systems that produce from high-sulfur coal, using the near-commercial technology shown in Figure 2^[32], both electricity and H₂ plus an electricity by-product. Calculations are presented both for the case where the separated CO₂ is vented and for the case where the

Box 2. Liquid fuel demand and supply in China

During 1990-1999 oil consumption in China grew 6.8 %/y, compared to 1.9 %/y for total primary energy. Moreover, during 1999-2020 oil consumption is projected to grow 4.3 %/y overall and 6.7 %/y for transportation applications [EIA, 2001]. The demand for LPG, the clean cooking fuel of choice wherever it is available and affordable, has been growing even more rapidly, at 21.9 %/year, 1990-2000, and future LPG demand growth is likely to be substantial^[24].

But domestic oil production grew only 1.5 %/y during 1990-1999, and in 1994 China became a net oil importer. By 1999 imports accounted for 20 % and 45 % of total oil and LPG consumption, respectively. One projection is that oil production will peak at a level slightly higher than at present during 2010-2020 [Wu et al., 2001]; the US Energy Information Administration projects that China's oil production will decline slowly between now and 2020 [EIA, 2001].

CO₂ is sequestered in a geological reservoir. The calculations presented for the CO₂ sequestration cases are for co-sequestration of the H₂S recovered from the syngas along with the CO₂ – thereby obviating investments in converting the H₂S to elemental sulfur, as assumed for the CO₂ venting cases. It is uncertain at present whether this co-sequestration strategy is viable, but if it is, the result is a net near-zero capital cost increment for H₂ production with CO₂ sequestration, because the added capital costs for CO₂ separation and compression to make the CO₂ disposal-ready are offset by capital cost savings from not having to convert the H₂S recovered from syngas into elemental sulfur. Under these circumstances the cost of H₂ production increases about 20% relative to the CO₂ venting case, to \$ 6.7/GJ, which is equivalent, in terms of energy content, to 22 ¢/liter (¢/l) of gasoline. For comparison, the average U.S. wholesale (refinery gate) gasoline price was 23 ¢/l in 2000. However, the cost to consumers includes not just manufacturing costs but also costs for distribution to refueling stations and for refueling stations. The total consumer cost in this example is 51 ¢/l of gasoline-equivalent energy [Williams, 2001] – compared to an average U.S. retail gasoline price (excluding retail taxes) in that year of 30 ¢/l. This high retail H₂ cost is not a “show-stopper”, however, because H₂ fuel cell cars would typically be 2-3 times as energy-efficient as typical internal combustion engine cars in use today [Steinbugler and Williams, 1998], so that the fuel cost per km would be less than with today's typical cars.

The cost penalty estimated for CO₂ disposal in Table 5 is for a case where the CO₂ is transported about 100 km from the coal conversion site and disposed of in a geological formation (e.g., deep saline aquifer) where there are no benefits from CO₂ disposal other than for climate change mitigation [Williams, 2001]. This cost penalty

might be reduced or even eliminated if there were opportunities for using the separated CO₂ for enhanced oil or coal bed methane recovery (see Section 9, “Outlook for disposal of CO₂” below).

Next-generation technology based on advanced inorganic membrane reactors for co-producing H₂ and electricity might lead to lower costs for making H₂ from coal [Williams, 2001].

7.2. The transition to fuel cell vehicles and H₂ as an energy carrier

Although there is much uncertainty relating to the future of H₂ fuel cells for both mobile and stationary applications, many private companies around the world are putting huge investments into fuel cell and H₂ technologies – in effect betting that the H₂ fuel cell has a promising future.

Stationary applications of H₂ are likely to come well before mobile applications and would be especially important in China in the light of the environmental urgency of replacing direct burning of coal in buildings for heating and cooking with the burning of clean alternative fuels. The option of using coal-derived syngas as town gas for these purposes was discussed earlier. Shifting from town gas (typically 35-40 % H₂) to H₂ (with essentially the same pipeline infrastructure) for heating and cooking applications would eliminate the risk of CO poisoning associated with accidental town gas leaks. Moreover, H₂ could be used for space-heating with essentially 100 % efficient catalytic combustors that can be vented directly into the heating space and generate essentially no NO_x [Ogden and Williams, 1989].

Also, distributed cogeneration at scales of 50-500 kW_e is likely to be an early market opportunity for H₂ PEM fuel cells – because for this application fuel cell costs have to fall to market clearing levels of hundreds of dollars per kW_e [Kreutz and Ogden, 2000], compared to much less than \$ 100/kW_e for automotive applications [Ogden et al., 2001]. PEM fuel cells offer major advantages over the internal combustion engine and microturbine distributed cogeneration options discussed earlier. In contrast to the high NO_x emission levels of internal combustion engine systems, PEM fuel-cell cogeneration units would be pollution-free. And H₂ PEM fuel-cell units would have electric conversion efficiencies roughly double the efficiencies of microturbines [Kreutz and Ogden, 2000].

Most of the technology cost buy-down for H₂ fuel cells will probably take place in industrialized countries during the coming 10-15 years. Nevertheless, there is much that China and other developing countries might do to prepare for the prospect that at some time during 2010-2020 H₂ fuel cells might be ready for widespread deployment worldwide. In particular, China might consider pursuing collaborative R&D and demonstration projects on technologies that are likely to be especially important to China. Consider, for example, that whereas the automobile is the focus of H₂ FCV development in the industrialized countries, the dominant modes of transportation in China and other developing countries are instead small passenger

Box 3. Methanol from coal via syngas

Methanol (MeOH) is a high-octane fuel that can replace gasoline in spark-ignited internal combustion engine vehicles (ICEVs). From the perspective of the ICEV owner, the main drawback of MeOH is its low volumetric energy density (half that of gasoline) – so that either larger fuel tanks or more frequent refueling would be required than with gasoline.

MeOH has attractive features relating to use in fuel-cell vehicles (FCVs). It is relatively easily reformed on board vehicles into a H₂-rich gas that fuel cells can use [Steinbugler and Williams, 1998], and, being a liquid, it is much easier and less costly to store than H₂. Moreover, its use in FCVs would lead to marked improvements in fuel economy and large reductions in air-pollutant emissions relative to use in ICEVs. Several auto manufacturers have plans to launch FCVs in the market using MeOH as fuel.

To date MeOH's role in automotive transport has been mainly in manufacturing MTBE (methyl tertiary butyl ether, an oxygenate additive to gasoline intended to reduce emissions while ensuring high octane rating), which is derived from MeOH by dehydration, although modest amounts of MeOH have also been used directly in blends with gasoline for cars in some regions.

MeOH can be produced from any carbonaceous feedstock via processes that begin with syngas production – for example, from natural gas via steam reforming or from coal via O₂-blown gasification or from biomass via steam gasification [Williams et al., 1995]. At present nearly all MeOH is produced from low-cost natural gas resources at remote sites.

Although MeOH use in ICEVs can lead to reduced oil dependence, its use offers little or no air-quality advantages relative to reformulated gasolines [Calvert et al., 1993]: CO emissions would be reduced and emissions of volatile organic compounds would be less problematic than for gasoline, but NO_x emissions would probably not be reduced.

If MeOH were to become widely used as an energy carrier for transportation, a concern is its toxicity via direct ingestion, absorption through the skin, or ingestion as a result of drinking methanol-contaminated groundwater^[26]. 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 [HEI, 1987]. In the case of groundwater contamination, risks are generally much less than for MTBE, because in most situations MeOH would degrade quickly. However, oil companies – having been burned by recent decisions to ban MTBE after having made enormous MTBE production investments 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.

vehicles (e.g., two- and three-wheeled vehicles), buses, trucks, and locomotives – the mix of which varies markedly from region to region. All of these, as well as cars, would have to become foci of serious international collaborative developmental efforts during the next 10-15 years in order to provide a basis for technologies characterized by near-zero emissions subsequently playing major roles in the transport sectors of China and other developing countries.

Also, advanced H₂ production technologies might be exploited well in advance of the introduction of H₂ as an energy carrier – for example, in industrial process markets such as NH₃ manufacture (especially important in China) that require H₂ as an intermediate product. China might consider pursuing collaborative R&D and demonstration projects with industrialized country partners aimed at bringing advanced coal-based H₂-making technologies to market.

7.3. Dimethyl ether – the third major energy carrier for the 21st century?

The energy system in the long term should involve use of no more than the minimum number of new energy carriers required to satisfy human needs because of the large infrastructure investments required to support each additional new energy carrier.

Without a major breakthrough in electric storage technology, at least one clean fluid fuel is needed as a complement to electricity. As argued above, environmental constraints make H₂, which is much easier to store than electricity, a strong candidate fluid energy carrier for a society reluctant to abandon fossil fuels. Can an energy system be designed at attractive costs on the basis of only electricity and H₂? For densely populated urban areas most energy needs could probably be satisfied with only these two energy carriers. However, the low volumetric energy density of H₂ makes its storage and transport infrastructure costly in regions of low population density where demand levels are low and demand profiles are peaky (non-diversified).

For rural areas, which characteristically have low population densities, an easily storable carbon-based fluid fuel will probably be needed – even in the long term. But if a new carbon-based fuel is to be introduced, it should probably be far cleaner than today's hydrocarbon-based liquid fuels, derivable from a wide variety of primary feedstocks, and useful in many applications.

The only way a carbon-based fuel can be made climate-change neutral is if it is derived from biomass that is grown on a sustainable basis^[33]. However, where biomass supplies are unavailable or inadequate to meet needs or

Box 4. Synthetic middle distillates from coal via syngas

Synthetic middle distillates (SMDs) are straight-chain hydrocarbon fuels (paraffins and olefins) produced via the Fischer-Tropsch (F-T) process. The F-T process begins with the production of syngas from a carbonaceous feedstock – e.g., from natural gas via steam reforming or partial oxidation or from coal via O₂-blown gasification or from biomass via steam gasification.

SMDs are good fuels to use in compression-ignition engines, in part because of their high cetane numbers^[27]. Moreover, they contain no sulfur, benzene, or other aromatic compounds. Measurements have shown 13-37 % reductions in particulate emissions and 6-28 % reductions in NO_x emissions relative to diesel fuel [Sirman et al., 1998; Schaberg et al., 1997; Norton et al., 1998]. Even greater reductions would be likely if the engines were optimized for use with these fuels, including exhaust gas after-treatment 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 mainly on use of low-cost supplies of natural gas. Despite high production costs, Shell's small, natural-gas-based Malaysian SMD plant (producing 1700 t per day) has 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 co-products (for example, waxes) in niche markets. Efforts to reduce costs will involve building larger plants. For example, Exxon is considering building a large (13,500-27,000 t a day) SMD plant with 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 Section 8, "Polygeneration strategies for syngas energy", below).

too costly, wide use of modern carbon-based fossil energy systems in rural areas would often be compatible with climate constraints because in a climate-constrained world there is no need to reduce CO₂ emissions to zero, and overall energy demand levels are typically low in rural areas [Goldemberg, 2000]^[34].

A strong candidate for becoming "the 3rd major energy carrier for the 21st century" is dimethyl ether (DME), a sulfur-free oxygenated synthetic fuel (CH₃OCH₃) that is super-clean and can be manufactured from any carbonaceous feedstock. Although it has the same atomic composition as ethanol (C₂H₅OH), DME is a gas at ambient conditions, whereas ethanol is liquid, but DME can be stored as a liquid in mildly pressurized canisters like those

used for LPG^[35].

Currently produced at a rate of 150,000 t a year, DME is used primarily as a propellant in aerosol spray cans^[36], but it is a versatile fuel – well-suited to cooking, transport, and power generation. Several large corporations are considering DME production/marketing – e.g., Haldor-Topsoe (Denmark), BP (UK), Air Products (US), and NKK (Japan). Moreover, DME production technology using natural gas as feedstock is commercially ready.

DME for cooking. About 2 billion people worldwide do not have access to clean cooking fuels and suffer from horrendous air pollution associated with using biomass and coal for cooking, as well as endure much drudgery if biomass is used for cooking.

LPG is the preferred clean cooking fuel where available and affordable. But, as noted earlier, domestic supplies are inadequate to meet demand in China and imports are growing rapidly.

Researchers at the Institute of Coal Chemistry of the Chinese Academy of Sciences are investigating prospects for making DME from coal for cooking applications [Niu, 2000]. For such applications DME's combustion properties are similar to those of LPG, though DME combustion generates less CO and hydrocarbon air pollution and is safer to use. An important consideration is that the infrastructure already established for LPG in China and other developing countries can be adapted, essentially without modification, to DME^[37].

DME as a transport fuel. Although H₂ fuel cells offer great long-term promise for transport applications, internal combustion engine vehicles (ICEVs) will dominate transportation for decades to come, so that China will need new ICEV fuel options even if H₂ turns out to be destined to be the transport fuel of choice for the long term.

Compression-ignition (diesel-type) engine vehicles are more important in China's transport sector than in the United States, where spark-ignited engines dominate^[38]. Although compression-ignition engines are ~25 % more fuel-efficient, air pollution damage costs are far greater, especially from particulate and NO_x emissions [Williams, 2000; Ogden et al., 2001], so that there is a pressing need for cleaner fuels (as well as cleaner engines).

DME is well suited^[39] for use in compression-ignition engines – offering high cetane number and potentially low emissions without tailpipe emission controls. Because it has no carbon-carbon bonds, soot emissions from its combustion are zero; also, NO_x emissions can be much less than with ordinary diesel fuel. Truck engine emissions tests show that NO_x and particle emissions are down 55-60 % and 75 %^[40], respectively, relative to diesel fuel [Fleisch and Meurer, 1995].

The need for pressurized canisters makes the infrastructure challenge greater than for fuels that are liquid at atmospheric pressure, but this should be much less a problem in developing countries (where well-established LPG infrastructures^[41] can be adapted to DME) than in industrialized countries (where LPG infrastructures are relatively poorly developed).

Box 5. Hydrogen safety

Hydrogen is widely perceived to be an unsafe fuel, because it burns or detonates over a wider range of mixtures 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; this means providing vents at the highest points in ceilings. Considering all these issues, a major study of H₂ safety [Ringland, 1994] concluded “... H₂ can be handled safely, if its unique properties – sometimes better, sometimes worse, and sometimes just different from other fuels – are respected.”

In the longer term, if FCVs eventually come to dominate transportation, DME would remain an attractive energy carrier for transportation in rural areas where it is not practical to establish infrastructure for H₂ (the preferred energy carrier for FCVs) – because DME is easily reformed on board FCVs into a H₂-rich gas the fuel cell can use^[42].

DME for central-station power generation. Use of DME in modern gas-turbine combined cycles for central-station power generation is proven technology, for which emissions are as low as for natural gas combined cycles [Basu et al., 2001].

Moreover, making DME at large coal mine-mouth factories and transporting it to distant markets for use in power generation would help mitigate the coal/rail bottleneck problem that is impeding expanded coal use in China. DME used in a state-of-the-art (60 % efficient) combined cycle would require only 40 % as much fuel mass per kWh as a new coal steam-electric plant, and the cost per tonne-kilometre (tkm) of transporting DME by large pipeline would be about 60 % as much as for transporting coal by rail, so that the cost of fuel transport per kWh would be less than 1/4 as much as for a coal steam-electric plant. This advantage together with the much lower capital cost for the DME power plant implies that

a DME power plant located 2000 km from the coal mine could compete on a lifecycle cost basis with a conventional coal plant at the same site if the average plant capacity factor were 60 % or less without taking any credit for the environmental benefits of this strategy, even though at the fuel production site the DME would be almost 4 times as costly as the coal from which it is derived (see Table 6)! Thus, the DME power option could make remote coal resources much more accessible than at present, while at the same time enhancing the economic development of the coal-producing region by generating far more value added than if coal were simply extracted and transported to remote markets.

Finally, this DME power option offers greenhouse gas mitigation as well as air pollution mitigation benefits, because the primary coal requirements per kWh of electricity generated from DME are about 1/6 less than for the coal steam-electric option; the energy losses in DME manufacture are more than compensated for by the higher efficiency of power plant conversion (see Table 6).

DME manufacture. Today, DME is produced by catalytic dehydration of MeOH and is thus more costly than MeOH. However, an advanced single-step process developed 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 BP 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 et al., 1995].

The Haldor Topsoe technology is based on use of gas-phase reactors for converting syngas to DME. Both Air Products [Peng et al., 1997; 1998] and the NKK Corporation [Adachi et al., 2000] are developing DME production technology based on the use of liquid-phase reactors^[43] that produce DME in a single step with more efficient heat removal than is feasible with gas-phase reactors – especially important for DME in the light of the fact that all the major reactions in DME manufacture are exothermic. As shown below, these reactors offer great promise in “polygeneration” configurations.

In 1998 the India DME Project was launched as a collaboration involving BP, the Indian Oil Corporation, the Gas Authority of India, and the Indian Institute of Petroleum, with the goal of developing, producing, and marketing in India DME derived via Haldor Topsoe technology from low-cost Middle East natural gas, focusing initially on power markets. In China, a project has been proposed for building a large coal-to-DME production facility in Ningxia Province (800,000 t/y capacity) that would use Shell gasification technology and liquid-phase DME synthesis technology from Air Products, with significant investment from a Canadian company.

8. Polygeneration strategies for syngas energy

Just as cogeneration can lead to improved economics relative to production of electricity and process steam in separate facilities (see Table 4a), so can synthetic fuel

Table 4a. Cogeneration via coal IGCC vs. separate production of electricity and steam^[1]

Rates of activity and costs	Separate production facilities for electricity and steam			IGCC cogeneration plant ^[2]
	IGCC plant ^[2]	Industrial boiler	Total	
Power generation rate (MWe)	400	-	400	400
Process steam production rate, 10–15 bar (MW _{th})	-	400	400	400
Coal input rate (TJ/hr)	3.08	1.59	4.68	3.74
First law efficiency, LHV basis (%)	46.8	90.5	61.6	77.1
CO ₂ emission rate (t/hr)	274	142	416	333
Capital investment (\$ 10 ⁶)	453	197	650	537
Annual energy production cost (\$ 10 ⁶ /yr)				
Capital	52.19	22.69	74.88	61.86
O&M (4 % of capital cost/yr)	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 (¢/kWh)	For power:	For steam:		For power:
Gross cost	3.31	1.50	-	3.94
Credit for steam co-product	-	-	-	-1.50
Net cost	3.31	1.50	-	2.44

Table 4b. Cogeneration via coal steam-electric technology vs. separate production of electricity and steam^[1]

Rates of activity and costs	Separate production facilities for electricity and steam			PC cogeneration plant ^[3]
	PC power plant ^[3]	Industrial boiler	Total	
Power generation rate (MWe)	400	-	400	400
Process steam production rate, 10–15 bar (MW _{th})	-	400	400	400
Coal input rate (TJ/hr)	3.27	1.59	4.86	4.51
First law efficiency, LHV basis (%)	44.0	90.5	59.2	63.9
CO ₂ emission rate (t/hr)	291	142	433	402
Capital investment (\$ 10 ⁶)	453	197	650	612
Annual energy production cost (\$ 10 ⁶ /yr)				
Capital	52.19	22.69	74.88	70.50
O&M (4 % of capital cost/yr)	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 (¢/kWh)	For power:	For steam:		For power:
Gross cost	3.36	1.50	-	4.56
Credit for steam coproduct	-	-	-	- 1.50
Net cost	3.36	1.50	-	3.06

Source: Williams [2000]

Notes

1. Based on calculations by Dale Simbeck, SFA Pacific. Engineering/contingencies and general facilities are each 10 % of process capital equipment costs; the annual capital charge rate is 11.5 %; the coal price is \$ 1.04/GJ; the annual average capacity factor is 80 %.
2. The IGCC in both the stand-alone power plant and the cogeneration plant involves a Destec O₂-blown coal gasifier coupled to the combined cycle with steam-cooled gas turbine blades analyzed in Table 2a.
3. The stand-alone PC power plant is an ultra-supercritical unit; the cogeneration plant is a sub-critical unit.

Table 5. Electricity and H₂ production from coal using near-commercial technologies^[1]

	Electricity only ^[2] with CO ₂ :		H ₂ + electricity co-product ^[3] with CO ₂ :	
	vented	sequestered	vented	sequestered
Coal input rate (MW _{th})	876	1014	1723	1723
CO ₂ emission rate	191 gC/kWh	16 gC/kWh	36.9 kgC/GJ H ₂	2.7 kgC/GJ H ₂
CO ₂ disposal rate (tCO ₂ /hr)	-	307.8	-	523.2
H ₂ output rate (MW _{th})	-	-	1019.3	1015.6
Electric power balance (MW _e)				
Gas turbine output	314.7	335.1	0.0	74.4
Steam turbine output	172.2	170.9	154.4	109.5
Syngas expander output	14.1	28.7	31.4	30.7
Air separation unit + O ₂ compression	-42.9	-49.2	-83.5	-83.5
Gasification auxiliaries	-8.8	-10.1	-17.2	-17.2
CO ₂ compression (→ 150-bar)	-	-25.7	-	-43.6
Purge compressor for PSA unit	-	-	-	-10.2
N ₂ compressor	-32.3	-27.2	-	-
Other auxiliaries	- 6.9	- 7.9	-8.2	-6.9
Net power output	410.1	414.6	76.8	53.2
1st law efficiency (η _{1st}) (%) ^[4]	46.8	40.9	63.6	62.0
Eff. efficiency (η _{eff}) of H ₂ production (%) ^[4]	-	-	65.4	63.1
Plant capacity factor (%)	80	80	80	80
Installed capital cost (\$ 10 ⁶) ^[5]	601.0	667.7	793.2	794.2
Energy production cost by component	Electricity cost (¢/kWh)		H ₂ cost (\$/GJ)	
Capital (ACCR = 11.5 %) ^[6]	2.41	2.65	3.55	3.57
O&M (4 % of “overnight” capital/year)	0.72	0.79	1.06	1.06
Coal input (@ \$ 1.12/GJ)	0.86	0.99	1.89	1.90
CO ₂ disposal (@ \$ 5/tCO ₂)	-	0.38	-	0.72
Electricity co-product credit (P _E = electricity price in \$/kWh)	-	-	-20.93×P _E	-14.56×P _E
Total cost with zero carbon tax (CT) ^[7]	3.99	4.80	5.66	6.67
Total cost with CT = \$ 30.4/tC ^[7]	4.57	4.85	6.67	6.67

Notes

- Energy balances and material flows were calculated using GS power generation/chemical process software developed at the Dipartimento di Energetica, Politecnico di Milano, Milan, Italy [Chiesa et al., 2002]. Based on a Texaco O₂-blown gasifier with quench (@ 70 bar, 1327°C). CO₂ recovery cases involve CO₂ compression to 150 bar for disposal. The disposal cost (for pipelines, disposal wells, and surface facilities) is assumed to be \$5/tCO₂.
- Without CO₂ separation/recovery: an IGCC plant with a steam-cooled gas turbine; a glycol solvent removes H₂S, which is converted to elemental sulfur. With CO₂ separation/recovery: the same IGCC unit except that shift reactors are added where steam reacts with CO to form CO₂ and H₂, and Selexol (a glycol solvent) is used to remove simultaneously from the shifted synthesis gas H₂S and CO₂ for co-disposal.
- Without CO₂ separation/recovery: gasifier plus shift reactors; a glycol solvent removes H₂S, which is converted to elemental sulfur; a pressure-swing-adsorption (PSA) unit separates out H₂; a steam turbine is fueled by PSA purge gas. With CO₂ separation/recovery: Selexol is used to remove simultaneously H₂S and CO₂ from the shifted synthesis gas for co-disposal; a PSA purge gas compressor compresses the purge gas for combined-cycle use.
- η_{1st} = (electricity + H₂ output)/(coal input); η_{eff} = (H₂ output)/(coal input – coal saved).
- Includes costs for CO₂ separation and compression and interest during construction (assuming a 10 % interest rate, a 4-year construction period).
- The annual capital charge rate (ACCR) for: a 10 % discount rate, a 25-year plant life, a 0.5 %/y insurance rate.
- In H₂ production cases, the electricity co-product value is the lesser of the costs for making electricity only.

production economics be improved by polygeneration – including as co-products various combinations of electricity, steam, town gas, and chemicals [Williams, 2000; Ni et al., 2001].

The polygeneration concept is illustrated here by discussing synthetic fuel manufacture using new liquid phase reactors in polygeneration configurations.

As already noted, O₂-blown gasification to produce syngas is the most important single enabling technology

that can make it possible for China to continue to exploit its vast coal resources with low (and ultimately near-zero) air emissions. Another important enabling technology is liquid-phase reactor technology for producing clean synthetic fuels. This technology is currently commercially available for producing both MeOH and SMDs from coal. Liquid-phase technology for making DME from coal can be commercialized soon, because the same reactor already developed for MeOH manufacture can be adapted to DME

Table 6. Alternative coal-based power systems^[1]: mine-mouth and near-market options

	Combined-cycle ^[2] , coal-derived DME	Coal steam-electric ^[3]
Installed capacity (MWe)	400	300
Installed capital cost (\$/kWe)	445	788
Efficiency, LHV basis (%)	60	33
Total coal consumed (g/kWh)	449 ^[4]	522
Fuel transported (g/kWh)	211 ^[4]	522
Generation cost (¢/kWh)		
Capital ^[5]	0.585/CF	1.036/CF
Fixed O&M	0.184/CF	0.328/CF
Variable O&M	0.15	0.50
Fuel (@ mine-mouth prices)	3.13 ^[6]	0.84
Total generation, mine-mouth	3.28 + 0.769/CF	1.34 + 1.364/CF
Fuel transport (2000 km)	0.28 ^[7]	1.22 ^[8]
Total generation near market	3.56 + 0.769/CF	2.56 + 1.364/CF
Generation cost @ CF = 0.595	4.85	4.85

Notes

1. For coal with a heating value of 20.9 MJ/kg and a coal mine-mouth price of \$ 0.77/GJ
2. The combined cycle with steam-cooled turbine blades described in Table 2a.
3. The coal steam-electric plant described in Table 2b equipped with ESP, wet FGD, and NO_x controls.
4. Per kWh generated, 6.0 MJ or (@ 28.4 MJ/kg) 211 g of DME is needed. It is assumed that the DME is manufactured from coal using the NKK liquid-phase reactor technology (64 % conversion efficiency) [Adachi et al., 2000], so that the coal input is 9.375 MJ or 449 g/kWh.
5. The annual capital charge rate is 11.5 %. Here CF is the average capacity factor.
6. The DME production cost at a mine-mouth plant producing 910,000 t/yr from coal @ \$ 0.77/GJ = \$ 5.21/GJ [Adachi et al., 2000].
7. The cost of transporting MeOH by pipeline (1.22 m diameter) at 103×10⁶ t/yr is estimated to be \$ 6.11/1000tkm (based on optimization to yield @ 15 % internal rate of return) [Kler et al., 1998] or \$ 4.83/1000-km/m³ (for MeOH with a density of 0.791 t/m³). For the same pressure drop per unit of pipeline, the volumetric flow rate for DME, Q_{DME} = Q_{MeOH}×(ρ_{MeOH}/ρ_{DME})^(1/2), where Q_{MeOH} = the volumetric flow rate for MeOH, ρ_{MeOH} = the mass density of MeOH, and ρ_{DME} = the mass density of DME = 0.668 t/m³, so that Q_{DME} = 1.088×Q_{MeOH}, and accordingly the DME transport cost = 4.83/1.088 = \$ 4.44/1000-km/m³ = \$ 6.65/1000 tkm or (since the energy density of DME is 19 GJ/m³), the cost of transporting DME 2000 km = \$ 0.47/GJ.
8. Losses in washing and transporting coal are assumed to be 3 % and the cost of transporting coal by rail is assumed to be \$ 11.3/1000tkm, so that the rail transport cost for coal with a heating value of 20.9 GJ/t is \$ 1.11/GJ.

manufacture. Costs for MeOH produced in liquid-phase reactors via once-through processes have been extensively analysed [Drown et al., 1997], and the technology is relatively well developed^[44].

No technological breakthroughs are required to launch polygeneration strategies in the market. There are opportunities today for providing clean energy via polygeneration at costs that are competitive with conventional energy.

Liquid-phase reactors are especially well suited for polygeneration applications. Because heat generated in exothermic reactions of synthetic fuel manufacture can be effectively removed from these reactors, high conversions can be realized in a single pass of syngas through the reactors, often making it attractive to limit conversion to what can be realized in a single pass. In such “once-through” processes, the unconverted syngas might be burned in a combined cycle to generate electricity or delivered via pipeline as town gas to distributed users.

Polygeneration strategies based on use of liquid-phase reactors in once-through configurations can lead to cost savings relative to single-product strategies both by means

of scale economies and by exploitation of potential synergisms – notably, avoiding capital investments associated with syngas recycling to improve conversion.

Particularly important will be polygeneration configurations that include electricity as a major co-product. Combined-cycle electricity from coal-derived syngas (which, as noted earlier, can be provided as cleanly as electricity generated in natural gas combined cycles) will be less costly when generated in polygeneration configurations than in power-only configurations – and can compete today with electricity derived from conventional coal steam-electric plants equipped with end-of-pipe air pollution control equipment. Moreover, the non-integrated gasifier/combined-cycle designs offering these economic benefits from polygeneration would be less complicated and more reliable than highly integrated IGCC designs that produce electricity only.

To illustrate polygeneration based on coal-derived syngas, Table 7^[45] presents calculations for product costs associated with various levels of polygeneration.

- The first option (400 MW of heat + 400 MW of electricity) presented summarizes the cogeneration calcu-

Table 7. Economics of polygeneration vs. single product energy production strategies based on coal^[1]

	Production capacity (MW)	Total cost (¢/kWh) charged to			
		Heat	Electricity	Methanol	Town gas
Single-product facilities					
Process heat	400	1.50			
Electricity	400		3.31		
Methanol	400			2.71	
Town gas	400				1.73
Single-product cost (in “natural” units)		\$ 4.17/GJ	3.31 ¢/kWh	12 ¢/l	\$ 4.81/GJ
Polygeneration facilities					
Cogeneration	400 + 400	1.50	2.40		
Trigeneration	400 + 400 + 400	1.50	2.40	1.55	
Quadrigenation	400 + 400 + 400 + 400	1.50	2.40	1.55	0.93
Cost via polygeneration (in “natural” units)		\$ 4.17/GJ	2.40 ¢/kWh	7 ¢/l	\$ 2.58/GJ

Source: Williams [2000]

Note

1. The cogeneration calculations are the same as in Table 4a. The trigeneration and quadrigenation calculations were developed by Robert Moore (formerly Air Products), building on the analysis in Table 4a, assuming Air Products’ liquid-phase reactor for MeOH production. Engineering contingencies and general facilities are each 10 % of process capital equipment costs; the annual capital charge rate is 11.5 %; the coal price is \$ 1.04/GJ; the annual average capacity factor is 80 %.

lations presented in Table 4a.

- In the second option, 400 MW of MeOH is added to the first option, leading to a 43 % reduction in production cost relative to producing only MeOH; the resulting production cost (1.55 ¢/kWh or \$ 4.3/GJ) is less than the average US refinery gate (wholesale, untaxed) gasoline price in 1999 (\$ 5.3/GJ).
- The third option adds 400 MW of town gas to the second option, leading to a 46 % reduction in production cost relative to producing only town gas; the resulting production cost (0.93 ¢/kWh or \$ 2.6/GJ) is less than the average US city-gate price of natural gas in 1999 (\$ 3.2/GJ).

The polygeneration market opportunities involving large-scale applications of process steam are limited in China^[46], where, as noted earlier, most of the process heat demand is associated with much smaller-scale installations. However, to the extent that niche market opportunities exist at all they might be exploited early on as an economically attractive option for launching coal syngas-burning combined-cycle technology in China’s energy sector.

Polygeneration facilities that include town gas as a co-product could probably do more to reduce urban air pollution than any other energy strategy China might pursue in the near term. In the longer term, the major co-products of polygeneration facilities would be one or more carbon-based liquid fuels (e.g., DME), hydrogen, and electricity. Because of the attractive economics offered and the prospective large market opportunities, polygeneration could plausibly become the principal means of electricity generation from coal in the longer term – a prospect suggesting that the chemical process industry (where gasification technology in China is already well established)

might become the center of gravity for large-scale thermal power generation in China in the future.

The main barriers to adoption of the polygeneration option appear to be institutional rather than technological: because the most economically attractive options will often involve making electricity as a co-product at rates in excess of on-site electricity needs, economic viability will often depend on the ability of the polygenerator to sell the electricity co-product into the electricity grid at a fair market price. Reforms to promote more competition in power markets will be helpful in nurturing polygeneration and thus the launching of syngas-based synthetic fuel technology in the market.

9. Outlook for CO₂ disposal

Conventional wisdom is that effectively addressing the climate change challenge requires abandoning fossil fuels. This is not so. As shown above, feasible technologies and strategies exist that make it possible to extract most of the energy contained in fossil fuels while simultaneously recovering the carbon as CO₂ and preventing its release to the atmosphere. Moreover, as shown above, there are advanced fossil energy technologies that can be brought to market over the next decade or so that offer near-zero emissions of air pollutants as well as near-zero greenhouse gas emissions – and such technologies could provide energy services while incurring only modest increases in energy costs for CO₂ disposal.

But what are the prospects for safe disposal of CO₂? The options include CO₂ storage in both the deep ocean and porous geological media. Although ocean disposal has received the most attention, environmental concerns and other large uncertainties in its prospects have led to a shift of focus in recent years to geological (underground) stor-

age of CO₂ – in depleted oil and natural gas fields (including storage in conjunction with enhanced oil and natural gas recovery), in uneconomic (e.g., deep) coal beds (in conjunction with enhanced coal bed methane (CBM) recovery), and in deep saline aquifers [Williams, 2000; Bachu, 2001].

CO₂ injection for enhanced recovery of oil [Blunt et al., 1993], natural gas [van der Burgt et al., 1992; Blok et al., 1997], and coal bed methane [Byrer and Guthrie, 1999; Gunter et al., 1997; Stevens et al., 1999; Williams, 1999] might become profitable foci of initial efforts to sequester CO₂.

There are about 74 enhanced oil recovery (EOR) projects worldwide, mostly (66) in the United States, where in 2000 oil production via EOR reached 29,500 t per day (4 % of total US oil production), a by-product of which is the sequestration of 30 Mt of CO₂ annually. Most of the injected CO₂ comes from natural reservoirs of CO₂^[47], but 5 Mt per year comes from anthropogenic waste CO₂ sources [Stevens et al.(b), 2000].

In western Canada, where natural reservoirs of CO₂ are not available, natural gas rather than CO₂ injection is mostly used for EOR. However, recent analysis suggests that for oil prices of about \$ 20 per barrel (1 barrel = 136.4 kg), recovery of CO₂ from flue gases of coal power plants and use for EOR in the region would often be profitable [Edwards, 2000]. It follows that EOR in the region based on CO₂ recovered from syngas would typically be even more profitable, because separation of CO₂ from syngas would be less costly. Indeed, one project launched in 2000 involves transporting for EOR applications by-product CO₂ from a North Dakota (United States) plant making synthetic natural gas (from coal) to the Weyburn oil field in Saskatchewan (Canada); the 300 km pipeline carries 1.5 Mt of CO₂ annually to this EOR site in the Williston Basin. This analysis and experience suggest that CO₂ EOR projects be considered in China for appropriate mature oil fields even where natural reservoirs of CO₂ are not available, if economic conditions favor locating coal syngas projects within a few hundred km of prospective EOR sites.

Perhaps more important to China is the potential use of CO₂ for enhanced recovery of methane from beds of unminable coal. Large amounts of methane are trapped in the pore spaces of many coals, and, as noted earlier, CBM resources in China are substantial. Injection of CO₂ into such coals can sometimes lead to efficient methane recovery because typically CO₂ is twice as adsorbing on coal as is CH₄; it can therefore efficiently displace the CH₄ adsorbed on the coal [Gunter et al., 1997]. As CO₂ moves through the reservoir it displaces CH₄; the limited experience to date indicates that very little of the injected CO₂ shows up in the production well until most of the CH₄ has been produced [Gunter et al., 1997], so that the prospects for permanent sequestration of the injected CO₂ appear to be good. Of course, CO₂ sequestration in the coal bed would prevent subsequent mining of the coal. However, deep or otherwise unminable coal beds for which coal-mining is uneconomic might prove to be attractive

for CBM recovery and CO₂ sequestration, and large amounts of the coal in the ground are unminable^[48]. Williams [1999] proposed that China consider siting new plants for making NH₃ from coal at promising CBM recovery sites, using the CO₂ co-product of NH₃ manufacture for enhanced CBM recovery. Another possibility would be to site plants for making DME from coal at promising CBM recovery sites, using the CO₂ co-product of DME manufacture for enhanced CBM recovery^[49]. The Ordos Basin, China's largest coal basin, seems to offer reasonably good prospects for using CO₂ for enhanced CBM recovery; reservoir characteristics there are very similar to those of the San Juan Basin of the United States [Stevens, 2001], where since 1996 an independent CBM producer has been carrying out a commercial pilot application of CO₂ injection for enhanced CBM recovery [Stevens et al.(a), 2000].

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 et al., 1992; Summerfield et al., 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 and 400 GtC for oil and gas fields, respectively [Hendriks, 1994]; other estimates are as low as 40 and 90 GtC for depleted oil and gas fields, respectively, plus 20 GtC associated with enhanced oil recovery [IPCC, 1996]. 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 saline aquifers are much more widely available than oil or gas fields. Such aquifers are present in all sedimentary basins, the total area of which amounts to 70 million km² (two-thirds onshore and one-third offshore) – more than half the 130 million km² land area of the inhabited continents. Some sedimentary basins offer better prospects for CO₂ storage than others [Hitchon et al., 1999; Bachu and Gunter, 1999; Bachu, 2001]. To achieve high storage densities, CO₂ should be stored at supercritical pressures^[50], which typically requires storage at depths greater than 800 m^[51]. The aquifers at such depths are typically saline^[52] and not effectively connected to the much shallower (depths less than ~300 m) freshwater aquifers used by people.

Up until a few years ago it was generally thought that closed aquifers with structural traps would be required for effective storage. The potential global sequestering capacity in such traps 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, a growing body of knowledge [Bachu et al., 1994; Holloway, 1996] indicates that many large, regional-scale open aquifers with good top seals (very low-permeability layers) can provide effective storage, if the CO₂ is injected sufficiently far from aquifer boundaries

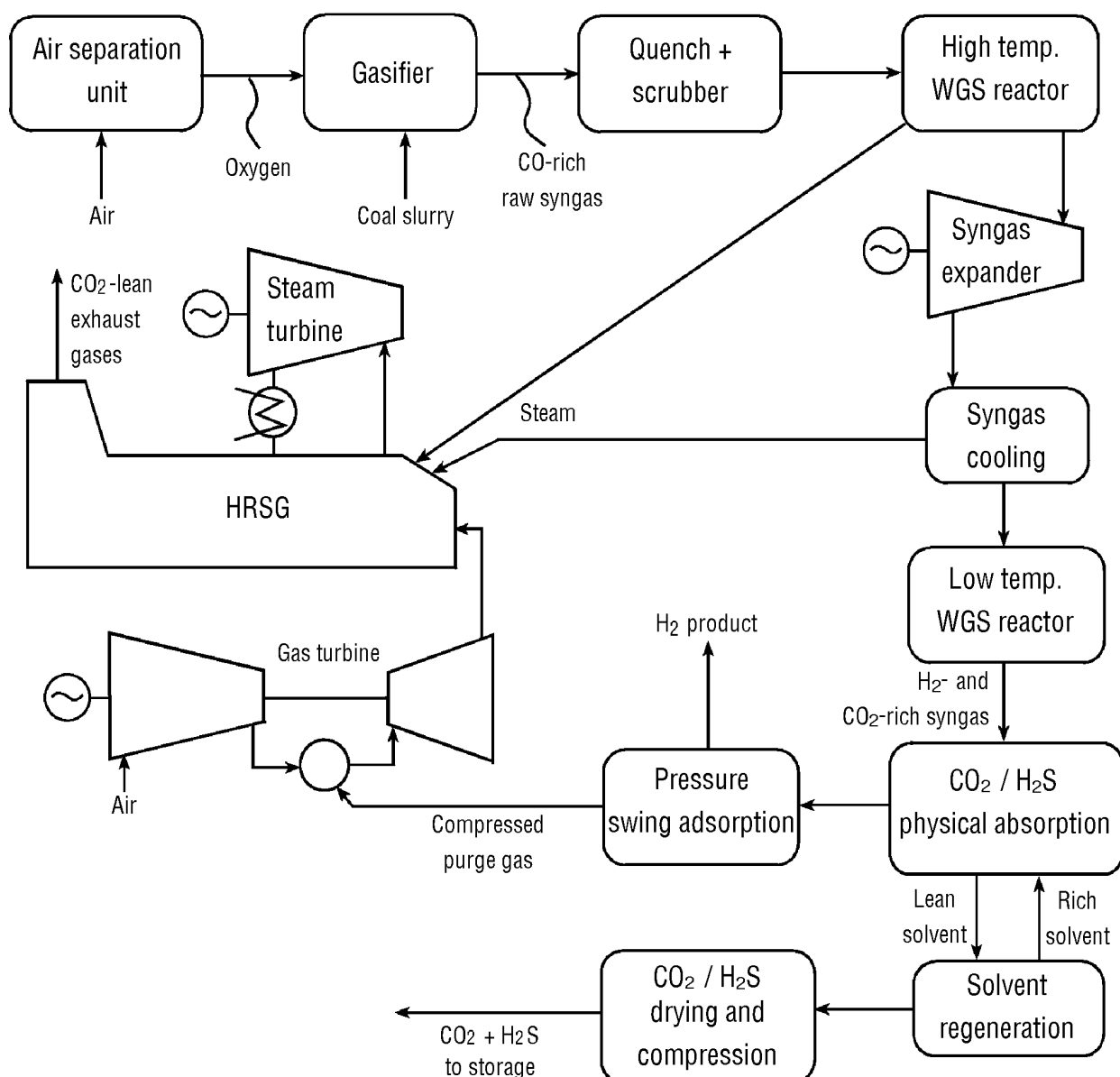


Figure 2. Hydrogen and co-product electricity generation from coal with near-zero emissions.

This is a schematic representation of the process described in the text. Performance and cost estimates are presented in Table 5.

that it either never reaches the boundaries, or if it does, the leakage rate would be sufficiently slow as to be of little consequence with regard to climate change, because of the extraordinarily slow rates of CO_2 migration in such reservoirs (typically of the order of 1 cm/y) – a phenomenon called “hydrodynamic trapping” of CO_2 [Bachu et al., 1994]. For large aquifers, the CO_2 will eventually dissolve in the water (“dissolution trapping” of CO_2). For sandstone reservoirs containing certain clay minerals (but not carbonate reservoirs), the CO_2 will, after dissolving in the water, eventually precipitate out as a carbonate mineral (“mineral trapping” of CO_2) [Gunter et al., 1993].

If structural traps are not required for effective storage, potential aquifer storage capacity might be huge; estimates range from 2,700 GtC [Ormerod, 1994] to 13,000

GtC [Hendriks, 1994]. For comparison, estimated remaining recoverable fossil fuel resources (excluding methane hydrates) contain 6,000-7,000 GtC [Rogner, 2000]. The notion that large aquifers with good top seals can provide effective sequestration is a relatively new idea that has contributed to the growing confidence in the scientific community that long-term sequestration of a significant fraction of the next several hundred years of global CO_2 production from human activities might be feasible [Holloway, 1996; Socolow, 1997; PCAST Energy R&D Panel, 1997].

There is a growing base of experience with CO_2 disposal in aquifers. One large project being carried out by Statoil involves recovering the CO_2 contaminant in natural gas from the Sleipner Vest offshore natural gas field

in Norway at a rate of 1 Mt of CO₂/year and its injection into and sequestration in a nearby aquifer under the North Sea [Kaarstad, 1992]. Another large aquifer disposal project that will commence in 10 years will involve recovery of more than 100 Mt/year (equivalent to 0.5 % of total global emissions from fossil fuel-burning) from the Natuna natural gas field in the South China Sea (71 % of the reservoir gas is CO₂) [IEA, 1996].

There is also a rapidly growing number of smaller acid gas disposal projects. In Alberta^[53] there are 31 such projects^[54] that involve recovery of CO₂ along with H₂S from natural gas fields and injection of these acid gases (characterized by a wide range of relative concentrations) underground for storage, in aquifers as well as in depleted oil and gas fields. Underground disposal of CO₂/H₂S is pursued in these projects as a less costly strategy for responding to sulfur air emission regulations than the alternative of recovering H₂S from the natural gas and converting it to elemental sulfur [Longworth et al., 1996; Wichert and Royan, 1997].

The long history of experience with EOR, the growing body of experience with aquifer disposal, and extensive historical experience with underground gas storage are contributing to the growing scientific confidence in the reliability of geological media for storing CO₂. However, more research, field testing, modeling, and monitoring are needed to narrow the uncertainties relating to CO₂ storage in geological media.

Regulations that have been evolving for underground gas storage provide a good basis for defining the issues associated with formulating regulations for CO₂ storage [Gunter et al., 1999]. 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. 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 et al., 1999]. But more research is needed to clarify the issues.

10. Alternatives to syngas energy for coal in China

A coal energy strategy based on syngas and polygeneration has been proposed for China. To be sure, there are many other advanced coal technologies that could be pursued as well – but all come up short against syngas/polygeneration in their prospects for addressing the multiple environmental challenges of the 21st century while simultaneously keeping clean energy affordable [Williams, 2000].

Consider that ultra-supercritical steam (USCS), pressurized fluidized-bed combustion (PFBC), and air-blown IGCC options are all major advanced power generating technologies that, like O₂-blown IGCC, offer with current technology efficiencies in excess of 40 % – compared to the current average efficiency of ~30 % for China today. But none of these alternative options can offer the envi-

ronmental benefits and flexibility inherent in the syngas/polygeneration strategy [Williams, 2000]. Shifting from present coal steam-electric plants to coal-based USCS, PFBC, or air-blown IGCC technologies can be likened to shifting from manual typewriters to alternative variants of electric typewriters. But shifting to syngas/polygeneration based on O₂-blown gasification is, by analogy, like shifting from manual typewriters to laptop personal computers. Just as it makes no sense to limit laptop computer use to word processing, it makes no sense to limit O₂-blown gasification technology to power generation via IGCC – rather this technology should be used for polygeneration as suggested in this paper.

Likewise, an alternative to syngas-based synthetic fuels (often referred to as “indirect liquefaction”) is direct coal liquefaction, which involves adding H₂ to coal in a solvent slurry at elevated temperatures and pressures. Direct liquefaction was commercialized in Germany and Japan to provide liquid fuels during World War II. Although interest in the technology virtually disappeared when low-cost Middle Eastern oil became available in the 1950s, interest 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. However, the introduction of aromatic-rich fuels that are derived via direct liquefaction would represent a step backwards for environmental management, because new environmental regulations aim to propel a shift to inherently cleaner fuels – for example, recent US regulations limit aromatic content of transport fuels [Williams, 2000]. A review of direct coal liquefaction technology by a panel convened by US President Clinton to advise him on energy research and development needs for addressing the 21st-century challenges posed by conventional energy [PCAST Energy R&D 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, and (in contrast to syngas-based strategies that can evolve to where H₂ is a major energy-carrier with low-cost sequestration of the separated CO₂) would provide no obvious path to achieving deep reductions in CO₂ emissions over the longer term. Because of such considerations, the panel recommended that the US Department of Energy terminate federal research and development funding for direct coal liquefaction and shift the freed-up resources 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.

11. Conclusion

A syngas/polygeneration strategy for coal could put China on an evolutionary path to a future in which coal energy systems could one day be characterized by near-zero emissions of both air pollutants and greenhouse gases. Under this strategy coal could be made as clean as natural gas

in terms of air pollution with technologies that could be deployed cost-effectively in the near term. And making syngas/polygeneration the cornerstone of this strategy would facilitate a shift over the longer term to an energy system based primarily on H₂, electricity, and at least one clean high hydrogen/carbon ratio synthetic fuel such as DME – with most of the carbon in the coal feedstock recovered as CO₂ and sequestered in appropriate geological formations.

It has been noted that if this syngas/polygeneration approach to coal were to come to dominate coal conversion, the center of gravity for power generation in China might shift from the power industry as it is known today to the chemical process industry, which already has considerable experience with O₂-blown gasification, the key enabling technology.

It is also noteworthy that in the world at large the petroleum industry is already moving ahead with syngas/polygeneration. Simbeck and Johnson [1999] have pointed out that there are already many polygeneration projects worldwide based on gasification of petroleum residuals at refineries that are being carried out without subsidies (see Table 3). Moreover, the co-production of clean synthetic liquid fuels and electricity has been identified as an economically attractive option for exploiting remote natural gas resources if markets are available for the electricity co-product [Choi et al., 1997].

Such considerations suggest that the way forward for a syngas/polygeneration strategy in China might be outside the traditional electric power industry and might involve using petroleum residuals and remote gas as well as coal. But because achieving attractive economics in polygeneration will typically involve electricity as a major co-product, public policies that encourage competition in electric power generation would be needed.

Although the syngas/polygeneration approach to coal can be launched in the market with existing technologies, long-term success will require high rates of technological innovation. International collaborations in research, development, and demonstration, especially via industrial joint ventures involving the oil, gas, and coal industries, would be desirable to bring the needed innovative capacity to this challenge, with governments enacting policies that would facilitate such private-sector-based collaborations [PCAST Panel on ICERD³, 1999].

None of this will happen as long as the environmental problems posed by coal are allowed to fester. But if governments were to set tough environmental goals for coal, the technology community could respond by transforming coal into an environmentally attractive energy source. It is not unreasonable to speculate that conventional wisdom regarding coal, as “the dirtiest of the fossil fuels – away from which countries evolve as they get richer”, will be transformed into a view that coal offers, because of its abundance and low cost and the technological availability of the syngas/polygeneration approach to conversion, “the least costly route to near-zero emissions for energy”. ■

Acknowledgments

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Notes

- Recent World Bank-sponsored research indicates that the actual reduction in China's coal use since 1996 is less than reported in these statistics, and, according to a newspaper account, China will revise upward its estimates for coal consumption in 1999, wiping out half the previously reported reduction [Pomfret, 2001].
- Proved reserves of coal in China amount to 166 billion tonnes (Gt) = 119 Gt of coal equivalent (Gtce) = 3,487 EJ = 108 years of primary energy consumption at the 2000 rate of 32.3 EJ/year [Ni and Sze, 1998].
- Estimated ultimately recoverable coal resources in China amount to 960 Gt = 685 Gtce = 20,070 EJ = 621 years of primary energy consumption at the 2000 rate [Ni and Sze, 1998].
- China's CBM resources to a depth of 2000 m are estimated to be 30-35 trillion Nm³ (Tm³) (1,200-1,400 EJ) at depths less than 2000 m [Rice et al., 1993; Sun and Huang, 1995]; another estimate [Murray, 1996] is that the upper limit of the total CBM in place in China is 75 Tm³ (2,700 EJ), which is less than the energy content of China's proved coal reserves.
- For a fixed level of pollution control technologies, health damage costs from coal (in \$/yr)
 - ∝ [pollutant emission rate (t/yr)] x [specific value of pollutant emissions (\$/t)]
 - x [density of exposed population (persons/km²)].
 - Very roughly:
 - Pollutant emission rate ∝ primary coal consumption (C)
 - ∝ [gross domestic product (GDP)]^α
 - Specific pollutant emissions value measured on basis of “willingness to pay” to avoid health damage
 - ∝ [per capita gross domestic product (GDP/P)]
 - Population density typically ∝ [population (P)]
 - so that health damage costs ∝ (GDP)^{α+1}. The US Energy Information Administration [EIA, 2001] estimates for the period 1999-2020 that GDP in China will increase 4.1-fold at the same time that coal consumption increases 2.4-fold, so that α = 0.587, which implies that health damage costs would grow 9.4-fold in this period if pollution control levels in China are not increased.
- Air is 20.9 % O₂, 78.1 % nitrogen (N₂), and 0.9 % argon (Ar).
- This O₂-rich gas also contains 3.6 % Ar and 1.4 % N₂.
- Coal with: a LHV = 29.6 MJ per kg; sulfur, ash, and moisture content by weight of 3.2 %, 7.0 %, and 5.5 %, respectively; the distribution of carbon, hydrogen, oxygen, and sulfur elements in a “mole” of this particular coal that can be represented heuristically by the formula CH_{0.8253}O_{0.0582}S_{0.0166}.
- In entrained-flow gasifiers finely-divided coal particles react simultaneously with an oxidant (usually O₂) and steam at high temperatures (well above the temperatures at which coal slagging occurs). For this type of gasifier coal residence times are very short. The present analysis is focused on entrained-flow gasifiers.
- The main reactions are: (1) partial oxidation (C + 1/2 O₂ → CO, a highly exothermic reaction that provides heat for coal devolatilization and various endothermic reactions involved in gasification; the produced CO has 72 % of the heating value of the carbon from which it is derived); (2) the water-gas reaction (C + H₂O → CO + H₂, a highly endothermic reaction); and (3) the water-gas-shift reaction (CO + H₂O → H₂ + CO₂, a mildly exothermic reaction; the H₂ generated has a slightly lower heating value than the CO consumed).
- Burning this coal with exactly the amount of O₂ needed for complete combustion can be represented as:

$$\text{CH}_{0.8253}\text{O}_{0.0582}\text{S}_{0.0166} + 1.194 \text{ O}_2 \rightarrow \text{CO}_2 + 0.4127 \text{ H}_2\text{O} + 0.0166 \text{ SO}_2.$$
- In this paper the energy content of fuels is presented in terms of the lower heating value.
- Providing the needed O₂ requires nearly 350 kWh/t of O₂, and the fuel-equivalent energy required to make this electricity amounts to almost 8.5 % of the energy content of the coal consumed for gasification via the Destec gasifier described above [Simbeck et al., 1993].
- For the Destec gasifier, high-pressure steam with an energy content up to nearly 12.5 % of the energy content of the coal consumed can be generated by heat recovered from syngas cooling [Simbeck et al., 1993].

15. Removing H₂S from syngas lowers its energy value, but even so the LHV of the sulfur-free syngas would be reduced only modestly (e.g., from 82.5 % to 80.8 % of the coal heating value for the example considered above).
16. In this expression the amount of O₂ involved is more than the stoichiometric amount. Typically there is 6 % O₂ in combustion product gases (as is assumed here) to ensure complete combustion as a response to regulations limiting CO emissions.
17. FGD strategies for sulfur removal involve reacting SO₂ with limestone to produce calcium sulfate (gypsum): $\text{CaCO}_3 + \text{SO}_2 + 1/2 \text{O}_2 \rightarrow \text{CaSO}_4 + \text{CO}_2$, so that 4.25 t of calcium sulfate are generated for each t of sulfur removed. In practice, when the calcium sulfate is disposed of as a waste, the amount of sulfur-related solid waste ("sludge") to be disposed is about 75-80 % more than this because of the presence of inerts in limestone and bound and free water associated with the waste. An alternative to sludge disposal (e.g., in a land-fill) is to sell the recovered gypsum to wall-board manufacturers – in which case the sulfur-bearing waste volumes to be disposed of can be reduced to what is required for disposal of "off-spec" gypsum. However, under current market conditions the overall economics of FGD with by-product gypsum sales for wall-board manufacture are less favorable than the overall economics of sulfurous gas removal from syngas with sulfur by-product sales [Simbeck et al., 1993]. FBC units make it possible to reduce SO₂ emissions by adding limestone to the bed of the FBC unit – again according to the reaction: $\text{CaCO}_3 + \text{SO}_2 + 1/2 \text{O}_2 \rightarrow \text{CaSO}_4 + \text{CO}_2$. Ideally, 1 mole of CaCO₃ is needed to remove 1 mole of SO₂. In practice, not all the limestone is effective in removing SO₂, so that the limestone added must be 2.0-2.5 times the stoichiometric amount, so that the sulfur-related solid waste is 6 to 13 times the mass of sulfur removed [Simbeck et al., 1993]. With FBC technology it is not practical to recover gypsum, which is intimately mixed with other wastes. The large solid waste disposal problem posed by FBC systems limits the use of this approach mainly to low-sulfur coals and typical sulfur removal rates of no more than about 90 %.
18. For this calculation it is assumed that efficiencies are: (1) 80 % for town gas production; (2) 30 % and 50 % for cooking with coal and natural gas, respectively, and 50 % and 75 % for heating with coal stoves and new natural gas boilers, respectively [Wu et al., 2001]; and (3) for syngas use in gas-burning equipment, essentially the same efficiencies as for natural gas.
19. According to Wu et al. [2001], NO_x emission rates are 0.44 kg/GJ for coal consumed in stoves and 0.11 kg/GJ for natural gas consumed in stoves and new boilers. It is assumed that the NO_x emission rate for town gas equals that for natural gas. Taking into account conversion efficiencies, NO_x emissions would thus be reduced 85 % for cooking and 83 % for space-heating.
20. These large syngas projects that involve electricity as a product or co-product are part of a recent global inventory of syngas projects compiled by Simbeck and Johnson [1999] that involves 161 real and planned commercial-scale projects with a combined syngas production capacity of 56,780 MW_{th}.
21. For the cogeneration systems described in Tables 4a and 4b 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-to-heat output ratios for steam turbines compared to combined cycles (see Figure 1).
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 g/kWh (9 ppmv at 15 % O₂) for the 28-kW_e Capstone Model 330 using a non-catalytic staged combustion system.
24. Continued rapid growth in consumption of LPG (or its market equivalent) is suggested by an international comparison: although total LPG consumption in China in 1999 was highest among developing countries (with a consumption rate 20 % higher than in Mexico, the second highest consumer), the per capita consumption rate in China was only 13 g/day, compared to 42 in Thailand, 73 in Taiwan, 97 in Malaysia, and 185 in South Korea. Moreover, satisfying just the requirement for clean cooking fuel with LPG implies a per capita LPG consumption rate of about 150 g/day.
25. The CO₂ co-product of making H₂ from coal can be recovered in a nearly pure stream suitable for geological disposal. With commercially available technology, the production from coal of H₂ and co-product CO₂ is carried out in a manner similar to that described in Box 5 for the process involving CO₂ removal from the "fuel gas" of a coal IGCC power plant. But the H₂ production case (unlike the IGCC case) involves using a gaseous separation technology such as pressure swing adsorption (PSA) after CO₂ removal to separate out very pure (e.g., 99.999 % pure) H₂ from the H₂-rich syngas, along with burning the residual syngas (containing CO, H₂, and perhaps also some CH₄) to make power in a steam turbine or combined-cycle power plant. With current technology the overall efficiency of making H₂ from coal is about 63 %, including the energy penalties for sequestering CO₂ in geological reservoirs – see Table 5.
26. A liter (l) of water would contain a fatal dose if it were contaminated with 2–7 % MeOH by weight.
27. High cetane number (a measure of a fuel's ability to auto-ignite) is desirable for compression-ignition engine fuels 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.
28. Ogden et al. [1998; 1999] designed a H₂ fuel-cell car which, relative to today's typical cars, would have lower aerodynamic drag, less rolling resistance, and reduced weight – without compromising performance and interior space requirements. Its estimated gasoline-equivalent fuel consumption is .022 l/km. H₂ would be stored on board as a gas compressed to 345 bar in cylinders with an aggregate storage capacity of 3.75 kg of H₂ – providing a range of 680 km between refuelings. State-of-the-art system storage densities for canisters (carbon-fiber-wrapped tanks with aluminum liners) are 7.5 % H₂ storage by weight, so that the loaded storage system weight is 50 kg. It is assumed that the H₂ is stored in 3 cylindrical canisters, each of which is 103.4 cm long and has an outside diameter of 28.3 cm. The total storage system volume is 195 l. These cylinders might be stored in a compartment under the car's roof – as demonstrated for the Daimler-Benz NECAR II fuel-cell passenger van.
29. For MeOH or gasoline fuel-cell cars, the liquid energy carrier is converted on board the vehicle into a H₂-rich gas that the fuel cell can utilize.
30. From ~\$ 2800/kW for automotive fuel-cell engines manufactured one at a time by hand today to ~\$ 65/kW for mass produced fuel-cell engines that would make H₂ fuel-cell cars competitive with gasoline hybrid electric cars [Ogden et al., 2001].
31. So called because in these reactors CO is reacted with steam ("water gas") and the chemical energy in CO is "shifted" to H₂ in the mildly exothermic WGS reaction: $\text{CO} + \text{H}_2\text{O(g)} \rightarrow \text{CO}_2 + \text{H}_2$.
32. The technology is described as "near-commercial" because the assumed gasifier pressure (120 bar) is higher than pressures for commercially available gasifiers. Texaco offers commercial gasifiers that operate at 70 bar and is exploring prospects for gasifiers operated at up to 120 bar [De Puy et al., 1999].
33. So that CO₂ released in combustion is offset by that extracted from the atmosphere during biomass growth.
34. Consider providing clean cooking fuel in the form of coal-derived DME to the 2 billion people worldwide currently dependent on coal or biomass for cooking. At a clean cooking fuel demand level of 2.5 GJ/y per capita [Goldemberg, 2000] some 5 EJ of DME would be needed, the manufacture of which from coal would generate (without sequestering the CO₂ co-product of DME manufacture – see Section 9, "Outlook for CO₂ disposal") CO₂ at a rate of just 0.2 GtC/yr (3 % of total global CO₂ emissions from fossil-fuel burning) – quite a modest environmental externality compared to the enormous quality-of-life benefits access to such clean cooking fuels would provide.
35. At atmospheric pressure DME boils at -25°C, so it must be stored in moderately pressurized tanks, as is the case for liquefied petroleum gas (LPG), which boils at -42°C.
36. It was chosen as an ozone-layer safe alternative (it degrades quickly in the troposphere) to fluorinated hydrocarbons. It is also non-toxic and non-carcinogenic.
37. Although DME-filled canisters would be heavier (18.7 kg of DME would replace 14 kg of LPG) and contain less energy (532 MJ of DME would replace 645 MJ of LPG).
38. In the transport sector in 1999, diesel fuel use in China was 55 % of gasoline use, whereas in the United States diesel fuel use was only 37 % of gasoline use.
39. The volumetric energy density of liquid DME (20°C) is 19 MJ/l compared to 16 MJ/l for MeOH and 32 MJ/l for gasoline.
40. Particle emissions are not zero despite absence of carbon-carbon bonds and zero sulfur content. Some particles are apparently generated from engine lubricating oil [Fleisch and Meurer, 1995].
41. In some developing countries (e.g., Brazil), LPG is used as a fuel for taxis using the same storage canisters as are used for cooking applications and involving a swapping of empty canisters for filled canisters at refueling.
42. As noted earlier, some automobile companies are considering launching fuel-cell vehicles in the market using either gasoline or MeOH as the energy carrier that is reformed on board the vehicle into a H₂-rich gas the fuel cell can use. MeOH is much easier to reform than gasoline. And DME is even easier to reform than MeOH: both DME and MeOH have no carbon-carbon bonds to break, but the first step in reforming MeOH is to apply heat to vaporize it – a step that is not needed for DME, a gas at atmospheric pressure.
43. New liquid-phase reactors that 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 of syngas through the reactor.
44. Air Products and Eastman Chemicals tested liquid-phase MeOH production technology in a process development unit at LaPorte, Texas, which was designed to produce 6.9 kl/day and which operated for 7,400 hours. Following this, a commercial-scale plant (designed to produce 288 kl/day) went into operation in January 1997, at Kingport, Tennessee, under the US Department of Energy's Clean Coal Technology Program, to

- demonstrate the technology during a period of 4 years of expected plant operation.
45. The calculations presented in Table 7 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. 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 here. But these tables illustrate the value of evolving towards systems based on large single-train systems and thus represent good targets for development.
 46. Typically polygeneration strategies that do not produce process steam as a co-product will still often make economic sense.
 47. Most of the EOR in the United States takes place in the Permian Basin of Texas. Most of the CO₂ for these projects is transported by pipeline from natural reservoirs of CO₂ in Colorado, New Mexico, and Wyoming (e.g., via an 800 km pipeline from the McElmo Dome in western Colorado – which contains 0.5 Gt CO₂).
 48. For example, 90 % of the nearly 6 Tt of US coal resources deposited at depths less than 1800 m is unminable with current technology, either because the coal is too deep, the seams are too thin, or mining would be unsafe [Byrer and Guthrie, 1998].
 49. In the manufacture of DME from coal about 1/2 of the carbon in the coal feedstock ends up at the conversion facility as a relatively pure stream of CO₂.
 50. The critical point for CO₂ is 74 bar and 31°C.
 51. Because the hydrostatic pressure gradient is typically about 100 bar per km.
 52. Deep aquifers (–800 m or more below the surface) tend to be saline because the contained water is fossil water that has been there over geological time – time sufficient for the water to come into chemical equilibrium with the minerals in the host rock. Dissolved salts typically make the water brackish and often even briny.
 53. Recently an acid gas disposal project was launched in Texas [Whatley, 2000]. In this project (for which the CO₂/H₂S ratio in the acid gas is 2.65 by volume), CO₂ is injected at a rate of 6,200 t/y into an aquifer at a depth of 1700 m.
 54. Canadian acid gas disposal projects began in 1989; since then the number of projects has grown rapidly: to 6 by 1995, 22 by 1998, and 31 by 2000 (private communication from Stefan Bachu, August 2001).
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