Fuel Decarbonization for Fuel Cell Applications and Sequestration of the Separated CO_2

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Abstract

If a large-scale shift to low-temperature fuel cells for transport and for stationary combined heat and power applications could be brought about, the production of hydrogen-rich fuels (hydrogen or methanol) from carbon-rich feedstocks (natural gas, coal, or biomass) to serve these fuel cells would lead to the production of relatively pure CO_2 separated at the synfuel production facilities, as a "free" byproduct. If this separated CO_2 could be securely isolated from the atmosphere there would be large net reductions in lifecycle CO_2 emissions, whether the hydrogen-rich fuels were derived from natural gas, coal, or biomass. In the case of biomass, net lifecycle emissions would be negative if the separated CO_2 were sequestered, making it possible for biomass energy to play large roles in offsetting CO_2 emissions from other sources, while simultaneously substituting for fossil fuel. The reduction in lifecycle emissions would be much larger for hydrogen than for methanol derived from these feedstocks.

The most promising options for sequestration are depleted natural gas fields and saline aquifers. Sequestration in depleted gas fields would be a secure strategy for disposal if the original pressure of the natural gas field is not exceeded. Saline aquifers are much more widely available, but more research is needed to better determine the overall potential capacity, the security of storage, and the environmental impacts of aquifer disposal.

The cost of emissions reduction by sequestering the CO_2 separated at synfuel conversion facilities in depleted natural gas reservoirs or in saline aquifers would add only marginally to overall fuel costs to consumers. The cost of sequestration would be especially low for hydrogen derived from natural gas if the hydrogen production facility is sited near a depleted natural gas field in which the separated CO_2 would be sequestered. In this case the net cost of sequestration would be near zero, because enhanced production of natural gas from reservoir repressurization would nearly pay for the costs of sequestration. Deep reductions in emissions at low cost would be possible for hydrogen produced even from coal, if the CO_2 separated at the hydrogen production plant were sequestered in depleted natural gas fields or saline aquifers--showing that "climate-friendly coal" is not an oxymoron.

The Challenge of Stabilizing the Atmosphere

Since the pre-industrial era, the concentration of CO_2 in the atmosphere has increased from 280 parts per million (ppm) to 350 ppm, mainly as a result of the burning of fossil fuels. The consequences of the ongoing buildup are troubling though uncertain (IPCC, 1990; Manabe and Stouffer, 1993; 1994). Stabilizing the atmosphere at less than a doubling of the atmospheric concentration of CO_2 would require radical change in global energy technology. According to the Intergovernmental Panel on Climate Change (IPCC), stabilizing the atmospheric concentration of CO_2 at its present level would require that cumulative emissions of CO_2 over the period 1990 to 2100 be no more than 300 to 430 gigatonnes of carbon (GtC) (IPCC, 1994), corresponding to an average emission rate of 2.7 to 3.9 GtC/year, 1990-2100; stabilization at 450 ppm would require that cumulative emissions in this period be no more than 640 to 800 GtC, corresponding to an average emission rate of 5.8 to 7.3 GtC/year. For comparison the mean estimate of actual emissions in 1990 is 7.4 GtC (of which 6.0 GtC was due to fossil fuel burning). Moreover, IS92a, the reference scenario for global energy generated by the IPCC involves emissions increasing to 20 GtC/year by 2100, with cumulative emissions amounting to 1500 GtC, 1990-2100 (IPCC, 1994).

Recent advances relating to the prospects for renewable electric power-generating technologies--especially wind, photovoltaic, solar thermal-electric, and biomass power technologies--have lead various groups to be optimistic about the prospects for curbing emissions from the electric power sector over a period of many decades (Johansson et al., 1993; WEC, 1994; Anderson and Ahmed, 1995).

While this new outlook for renewable electric technologies is auspicious, successful development of a wide range of renewable electric technologies by itself would not make it possible to stabilize the atmosphere at near current levels, because most CO_2 emissions are from non-electric sources. In 1990, the electric sector accounted for 36 percent of global primary commercial energy use but only 29 percent of global CO_2 emissions from fossil fuels; in the IS92a scenario, it is projected that the electric sector in 2100 will account for 44 percent of primary energy use but just 25 percent of total CO_2 emissions from fossil fuel use[1] (despite a 6.3-fold increase in electricity demand, 1990-2100, compared to a more modest 4.2-fold increase in total primary energy use in this period), because of projected growing contributions to power generation from renewable and nuclear power sources (IPCC, 1992).

The major greenhouse challenge will be to avoid enormous increases in CO_2 emissions arising from the production of synthetic fuels from coal.[2] In the IS92a scenario, synthetic fluids account for 75 percent of all liquid and gaseous fuels used in 2100, and the amount of coal used for synthetic liquid and gaseous fuels production then is 4.2-times the total amount of coal use in 1990.

Synthetic fuels can be produced from non-fossil fuel sources. The prospect that low-cost photovoltaic (pv) power systems could become available (circa 2010-2020) with amorphous silicon and/or other thin-film pv technologies led in the late 1980s to a detailed technical/economic analysis painting a picture of world energy economy in which pv technology would be widely used not only to provide electricity that is used directly but also to provide hydrogen derived electrolytically from this electricity, for transport and various stationary markets (Ogden and Williams, 1989). While the outlook for low-cost pv technology based on thin-film devices is as good today as it was at the time of the Ogden and Williams study (Carlson and Wagner, 1993; Zweibel and Barnett, 1993), it is now known that the production of hydrogen from biomass via thermochemical gasification would be a much less costly route for producing hydrogen from a renewable energy source than hydrogen derived electrolytically from any source[3] other than off-peak power[4]--even if cost goals for thin-film pv technology are fully realized; moreover, the prospects are good that this biomass-derived hydrogen would be no more costly than hydrogen derived from coal via thermochemical gasification in many instances (Williams et al., 1995a; 1995b).

The growing of biomass for use with modern energy conversion technologies, either in large plantations or on many small energy farms (Larson et al., 1994), has been identified as an attractive climate-friendly energy strategy that simultaneously could provide an energy base for rural industrialization and employment generation in the developing world and make it possible to phase out agricultural subsidies in the industrialized world (Williams, 1994a). While it is inherently easier to grow biomass for energy in environmentally acceptable ways than is the case for food production (Larson et al., 1995), various groups are skeptical that biomass can be produced for energy at large scales in environmentally acceptable ways (WEC, 1994; Flavin and Lenssen, 1994).

This paper explores a strategy for decarbonizing fuels (both fossil and biomass) that would make it possible achieve deep reductions in CO_2 emissions, prospectively at a relatively low incremental cost for energy services, while reducing the amount of land resources needed for making energy from biomass and avoiding the large cost penalties associated with a possible premature commitment to solar electrolytic hydrogen in the quest for an energy future compatible with sustainable development goals.

Flue Gas Decarbonization vs. Fuel Gas Decarbonization

A technically feasible but costly option for achieving deep reductions in greenhouse gas emissions is to extract the CO_2 from flue gases of large fossil-fuel combustors (e.g. at fossil-fuel power plants) and to isolate the CO_2 so recovered from the atmosphere (Blok et al., 1989). This "flue gas decarbonization" strategy is costly largely because of the expenses associated with separation of the CO_2 from flue gases (in which the concentration of CO_2 is only 8-15 percent); once the CO_2 is separated out, the incremental cost of isolating the recovered CO_2 from the atmosphere can often be relatively modest (van Engelenburg and Blok, 1993; Hendriks, 1994).

A much more promising approach involves fuel decarbonization--the production of hydrogen or a hydrogen-rich fuel from a carbon-rich fuel, in the process of which a stream of essentially pure CO_2 is separated "free" as a byproduct--a process that might more appropriately be labeled "fuel gas decarbonization" (*see Appendix A*). Pioneering work on fuel gas decarbonization has been carried out at the University of Utrecht (Blok et al., 1989; Hendriks, 1994) and at Shell in The Hague (van der Burgt et al., 1992) in conjunction with the production of electricity from coal via integrated gasification/combined cycle power plants.

While the cost penalty for fuel decarbonization and sequestration of the separated CO_2 with this approach is far less than that for various flue gas decarbonization schemes, the electricity produced this way would nevertheless be about 30 percent more costly than with a conventional coal integrated gasifier/combined cycle power plant (Hendriks, 1994), simply because there are no direct economic benefits (only environmental benefits) arising from fuel gas decarbonization.

Because the production of hydrogen is inherently costly, it is desirable to use it in conversion equipment where it is worth more than conventional fluid fuels--especially since there is little prospect that the prices of conventional hydrocarbon fuels will rise high enough in the foreseeable future to the point where hydrogen will be able to compete on a $-per-GJ-equivalent basis. The true value of hydrogen should be determined not by a comparison of fuel costs but by a comparison of costs of providing an energy service such as the cost per vehicle-km of travel.

The use of hydrogen in low temperature fuel cells for transport and distributed combined heat and power applications could provide the needed high value. Fuel cells offer high thermodynamic efficiency and zero or near zero local pollutant emissions without the need for pollution control equipment. Moreover, for combined heat and power applications, the absence of scale economies for production units, the lack of need for operating personnel, low maintenance requirements, and low noise levels make it possible to site low temperature fuel cells near users where the produced energy is more valuable than at centralized facilities.

Until recently it has not been practical to take advantage of these attributes. The only commercial fuel cell is the phosphoric acid fuel cell. Its power density is too low for it to be considered for automotive applications, and its prospective costs in mass production are not especially low. However, recent advances relating to the proton-exchange-membrane (PEM) fuel cell indicate a hopeful future for this technology for both distributed combined heat and power (A. D. Little, 1995; Dunnison and Wilson, 1994) and transport[5] (Williams, 1993; 1994b; Mark, Ohi, and Hudson, 1994) applications. When mass produced for transport applications, its costs could be low, approaching the costs of internal combustion engines.[6]

Low-temperature PEM fuel cells can utilize very efficiently hydrogen or methanol that is reformed with steam to produce a gaseous H_2/CO_2 mixture onsite, or, in transport applications, onboard the vehicle.[7] Such fuels have good prospects for becoming major energy carriers in the "post-combustion" era, when electrochemically-based fuel cells will have become well established in the energy economy. The least costly ways of producing these energy carriers are from chemical fuel feedstocks--initially natural gas and later coal and biomass (Williams et al., 1995a; 1995b).

While the alchemists failed in their attempts to transmute base metals into gold, the technology for making hydrogen from carbon is well-established. Specifically, a carbon-rich fuel feedstock can be processed to produce hydrogen or methanol (a hydrogen carrier) by first converting the feedstock into "syngas" (a mixture of CO and H_2) via steam reforming (in the case of natural gas) or via thermochemical gasification (in the case of coal or biomass) and then shifting the energy contained in the CO to H_2 by reacting the CO with steam--a process requiring very little net energy input (*see Appendix A*). In the final stages of the manufacturing process, CO_2 is separated from the fuel product [e.g. using pressure swing adsorption (PSA) in the case of hydrogen production or Selexol in the case of methanol production] in a virtually pure stream that is available as a "free byproduct" (*see Table 1*).[8]

If there were no greenhouse problem, this stream of pure CO_2 would be vented to the atmosphere. In a greenhouse-constrained world, consideration might be given to isolating this CO_2 from the atmosphere because of the large potential and relatively low costs involved. If this stream of separated CO_2 could be stored in isolation from the atmosphere, CO_2 emissions would be sharply reduced.

Lifecycle CO_2 Emissions--Without and With CO_2 Sequestration

Without sequestration of the separated CO_2 there would be no significant reduction in lifecycle CO_2 emissions per GJ of fuel provided, in shifting from reformulated gasoline to methanol or hydrogen derived from natural gas; moreover, lifecycle emissions would roughly double in shifting from reformulated gasoline to methanol or hydrogen derived from coal (*see Table 1*). The only options based on the thermochemical conversion of fuels that offer significant greenhouse benefits without sequestration of the separated CO_2 are methanol and hydrogen derived from biomass that is grown on a sustainable basis; in these instances lifecycle emissions are just 5 and 10 percent of those for reformulated gasoline (*see Table 1*).

With sequestering, the balances are sharply changed. Lifecycle emissions for methanol produced from coal would be no more than for gasoline or for methanol produced from natural gas, while lifecycle emissions for hydrogen produced from either natural gas or coal with sequestering would be only about half of the emissions from gasoline[9] (*see Table 1*).

In the case of biomass grown on a sustainable basis, net lifecycle emissions with sequestering would be strongly negative (because the carbon in the plant matter was originally extracted from the atmosphere in photosynthesis) and, absolutely, more than twice as large for hydrogen production[10] as for methanol production (*see Table 1*). This characteristic of systems that involve the production of hydrogen-rich fuels from biomass with sequestering of the separated CO_2 makes it possible to achieve deep net reductions in global greenhouse gas emissions even if some countries are unable to achieve deep reductions or choose to ignore the greenhouse problem (*see, for example, Appendix B*).

If the end-use technology is taken into account, the emissions reduction potential with sequestration can be even more dramatic. Consider lifecycle emissions, measured in gr C per km of vehicular travel, for fuels used in fuel cell vehicles (FCVs) compared to emissions for gasoline internal combustion engine vehicles (ICEVs). Operated on gasoline, methanol, and compressed hydrogen, FCVs are expected to be, respectively, 1.8, 2.4, and 2.8 times as energy-efficient as comparable gasoline ICEVs (*see Table 2*). As a result, lifecycle emissions per km of travel for FCVs operated on methanol derived from coal with CO_2 sequestering are only 2/5 as large as for gasoline ICEVs. For FCVs operated on hydrogen derived from natural gas or coal with CO_2 sequestering, emissions per km are less than 1/5 of those for gasoline ICEVs and 1/3 of those for gasoline-fueled FCVs (*see Table 2).*

Options for Sequestering CO_2

The most-discussed option for CO_2 disposal has been piping CO_2 to depths greater than 3 km in deep ocean basins. So doing would eliminate the rapid transient buildup of CO_2 in the atmosphere and delay equilibration with the atmosphere by several hundred years; resulting interactions with calcite-rich sediments would probably reduce the long-term (> 2000 year) atmospheric concentration by a significant amount (~ 50 percent) (Wilson, 1992). But many questions remain about the dynamics of the processes involved, and many environmental issues have been raised--including concerns about the effects on ocean life of pH change from CO_2 injection, and the impacts on benthic organisms and ecosystems as hydrate particles are deposited on the ocean floor. Much more research is needed on such issues before deep ocean disposal can be pursued with confidence that the cure will not be worse than the disease (Turkenburg, 1992).

Among other options, disposal in depleted natural gas and oil fields stands out as being especially secure, as long as the original reservoir pressures are not exceeded (van der Burgt et al., 1992; Summerfeld et al., 1993), and potentially low in cost (Blok et al., 1989; van der Burgt et al., 1992; Koide et al., 1992, Hendriks, 1994). The global sequestering capacity associated with past production, proved reserves, plus estimated undiscovered resources is estimated to be 410 GtC for natural gas fields and 105 GtC for oil fields (Hendriks, 1994). For comparison, global CO_2 emissions from fossil fuel burning totalled 6.0 GtC in 1990.

The capacity of natural gas fields to sequester carbon at the original reservoir pressure is generally greater than the carbon content of the original natural gas and depends on the depth of the reservoir, the geothermal gradient, and the pressure gradient. Hendriks (1994) has shown that for typical gradients, the ratio of carbon in CO_2 to that in the original natural gas is 3.0, 1.8, and 1.4 for depths of 1, 2, and 3 km, respectively, and that worldwide, on average, about twice as much carbon can be stored (as CO_2) in depleted reservoirs as was in the original natural gas.

If a hydrogen production facility could be sited near a depleted natural gas field the costs of long-distance pipeline transport of CO_2 could be avoided. Moreover, the cost of injection into the reservoir could be offset to some extent by recovery of additional natural gas. When primary production of natural gas at a reservoir ceases, it is not because the contained natural gas has been exhausted but rather because the reservoir pressure falls below a certain level (typically of the order of 30 bar) at which it is no longer economic to continue pumping out natural gas. But with CO_2 injection, the reservoir is repressurized, so that enhanced natural gas recovery is possible. Because of the order of 80 percent of the natural gas in place is recovered in primary production, the amount of additional natural gas that can be produced is not large--but the enhanced production can pay for part or all of the incremental costs of CO_2 storage.

Based on data characteristic of large natural gas reservoirs in The Netherlands, Blok et al. (1995) have assessed the prospects for enhanced natural gas recovery with CO_2 injection, the implications for the net costs of CO_2 sequestration, and the impacts on the costs of producing hydrogen or methanol from natural gas. For the reservoir conditions they studied, extra natural gas production would contribute between 3.5 percent and 8.5 percent of the natural gas feedstock requirements for a hydrogen production plant over the first 15 years of its assumed 25-year operating life, depending on whether there were large or small permeability differences, respectively, between adjacent layers of the natural gas reservoir. The material balances for their analysis of the case where there are small permeability differences is shown in Figure 1.

There would be considerable capacity in depleted natural gas fields for sequestering CO_2 recovered from decarbonizing fuels other than natural gas. For example, when hydrogen is produced from natural gas, the CO_2 recovery rate [10.7 kg C/GJ of produced hydrogen (*see Table 1*) or 9.0 kg C/GJ of the natural gas from which it is derived (assuming all energy inputs are provided by natural gas)] is equivalent to just 2/3 of the carbon in the original natural gas (13.5 kg C/GJ). Since, on average, the CO_2 sequestering capacity is equivalent to about twice the carbon contained in the original natural gas, the production of hydrogen from natural gas would thus leave about 2/3 of the sequestering capacity available for CO_2 derived from other sources. In addition, the sequestering capacity associated with past natural gas production and future production that will not be associated with the manufacture of hydrogen and the sequestering of the separated CO_2 would be available.

The limitation on strategies for CO_2 sequestration in depleted natural gas and oil fields is their limited geographical availability. This should not be a significant constraint on hydrogen manufactured from fuel conversion facilities sited near the natural gas fields, since the produced hydrogen could be distributed long distances via pipeline at acceptable costs (*see Table 7 and Appendix C*), serving markets just as natural gas pipelines do today. However, it would be desirable to have sequestering options that are more widely available as well.

The most widely distributed reservoirs for potential sequestering of CO_2 are saline aquifers located deep below the earth's surface underlying most of the area of sedimentary basins throughout the world. The areal extent of these basins is equivalent to nearly half of the land area of the inhabited continents (*see Table 3a*). Aquifers are porous underground beds, consisting mainly of sand, that are permeable to the flow of fluids. The pore spaces are usually filled with water and, occasionally, with petroleum or natural gas as well. Only aquifers deeper than 750 meters are considered as potential storage reservoirs for CO_2. Aquifers containing fresh water are normally found at much shallower depths. If CO_2 were stored at a depth of 750 meters or deeper, it would generally take 2000 years or more to reach a fresh water reservoir, and even then it will probably reach the fresh water reservoir in low concentrations; the main effect of the CO_2 that would enter the fresh water reservoir would be to increase the hardness of the water, because carbonates will dissolve (Hendriks, 1994).

Hendriks (1994) has estimated the CO_2 storage capacity of such aquifers under the assumption that the injected CO_2 displaces water. He has made alternative estimates that depend on the extent to which structural traps are needed for secure storage (*see Table 3b).* Without a structural trap, the injected CO_2 might eventually migrate from the injection site to other subterranean sites where storage is not desirable or even to where it can escape to the atmosphere. At present the extent to which structural traps are needed to ensure secure CO_2 disposal is not known (Hendriks, 1994). If structural traps are not needed, the estimated worldwide sequestering capacity of aquifers is about 15,000 GtC; if structural traps are necessary, the sequestering capacity is 60 GtC (Hendriks, 1994). The security of CO_2 storage under alternative aquifer storage conditions, as well as the potential environmental impacts of aquifer storage, are not well understood at present (van Engelenburg and Blok, 1993).

Framing the Cost Analysis for CO_2 Sequestration[11]

The costs of alternative options for hydrogen production and use/CO_2 disposal are estimated here for hydrogen produced from natural gas, coal, and biomass, with a focus on automotive applications of the produced hydrogen.[12] Storage of CO_2 in both depleted natural gas fields and saline aquifers is considered. Various hydrogen production/CO_2 disposal scenarios are investigated. Costs are estimated for hydrogen production, for delivering hydrogen to users, and for using hydrogen. The estimated costs for CO_2 sequestration include the costs for drying and compressing the CO_2 to the pressures required for CO_2 transport and injection,[13] the costs of pipelines for transporting the CO_2 to the sequestering sites,[14] and the costs for wells and surface facilities at the storage sites.[15]

Hydrogen production cost estimates under alternative assumptions about sequestration are presented in Table 4 for natural gas, Table 5 for coal, and Table 6 for biomass feedstocks, as functions of feedstock prices. In all cases it is assumed that the CO_2 separated (at 1.3 bar) at the hydrogen production facility must be dried and compressed to 110 bar for delivery to a CO_2 pipeline or natural gas disposal well. In Table 7 hydrogen costs to consumers for transport applications are presented for base case scenarios for each feedstock as a function of the feedstock price, without and with sequestration, assuming typical sequestration costs in the latter instance.

For hydrogen production from natural gas with sequestration, it is assumed that the hydrogen plant is sited at a depleted natural gas field, in which the recovered CO_2 is sequestered, thereby avoiding long-distance CO_2 transport costs. Credit is taken for the modest increase in natural gas production that results from repressurization of the natural gas reservoir. It is assumed that: (*i*) as in the analysis of Blok et al. (1995), the increased natural gas production would contribute between 3.5 and 8.5 percent of the natural gas feedstock requirements for the hydrogen production plant; (*ii*) increased production takes place after 20 years of primary production; (*iii*) after 15 years of CO_2 injection there is no more increased production; and (*iv*) the benefits of increased production accrue to producers of hydrogen from natural gas for the situation where conversion plants are located near the disposal site.

Because natural gas field disposal sites are geographically limited, it is assumed for the base case scenarios that in order to reach typical final consumers the produced hydrogen is transported 1000 km further than is required for hydrogen that might be produced from coal or biomass at sites other than at depleted natural gas fields. To take advantage of the scale economies of pipeline transport of hydrogen, it is assumed that for the base case scenarios that the outputs of five large production plants (each having a production capacity of 19.1 PJ of hydrogen per year--*see Table 4*) are combined for hydrogen transport in a single 1000-km pipeline. The cost of hydrogen to consumers is estimated by assuming that after the initial 1000-km hydrogen transport journey, the produced hydrogen is further transported 100 km in intermediate-sized pipelines, followed by transport 10 km in small-diameter pipelines to refueling stations for automobiles, where the final costs tabulated in Table 8 are incurred.

Costs for hydrogen from natural gas with sequestration are compared to costs for two alternative configurations for making hydrogen from natural gas without sequestration: one in which hydrogen is produced near the natural gas field and piped to distant markets; and another in which natural gas is piped to a hydrogen production facility near these distant markets (*see Table 7*). Siting the facility for producing hydrogen from natural gas near hydrogen markets for one of the cases without sequestration is included because pipeline transport is less costly for natural gas than for hydrogen.

Two scenarios are considered for coal and two for biomass. In one scenario for each feedstock, the base case, it is assumed that the recovered CO_2 is transported by pipeline 250 km to a site where sequestration is feasible in a saline aquifer. Because saline aquifers are so widely available, it is assumed that the pipelines required to bring the produced hydrogen to market are much shorter than for the case where hydrogen is produced from natural gas with sequestration. Specifically, it is assumed that the produced hydrogen is transported 100 km in an intermediate-sized pipeline, followed by transport 10 km in small-diameter pipelines to refueling stations for automobiles, where the final costs tabulated in Table 8 are incurred. In the other scenario the coal is transported to a hydrogen production facility located near a depleted natural gas field, where the separated CO_2 is sequestered. However, it is assumed in this instance that: (*i*) natural gas field disposal of CO_2 occurs after disposal has already taken place there for hydrogen produced from natural gas, and (*ii*) unlike the natural gas case, no additional enhanced natural gas production can be credited against the cost of hydrogen produced from coal or biomass.

The costs of hydrogen to consumers from natural gas, coal, and biomass feedstocks, as functions of feedstock costs, are presented in Table 7, without and with sequestration, and without and with a carbon tax of $52/tC--a tax large enough to make the cost of hydrogen from natural gas with sequestration at the gas field equal to that for hydrogen produced from natural gas at a site 1100 km from the natural gas field, near large remote hydrogen markets, when the wellhead natural gas price is $3/GJ, and for average sequestration cost and average credit for enhanced natural gas recovery *(see Table 4*). The charge against the fuel cost to the consumer from this carbon tax is levied at the net lifecycle CO_2 emission rate for a given fuel, as indicated in Table 1. Hydrogen costs to consumers, along with gasoline costs for comparison, are also shown in Figures 2 and 3 for specific feedstock prices--without sequestration and for both low and high estimates of sequestration costs. (All fuel taxes are excluded in these figures.) In Figure 2, these costs are presented per unit of per unit of delivery energy ($ per GJ); in Figure 3, they are presented per unit of transport energy services provided (cents per km of driving), assuming the hydrogen is used for automobiles. The estimated total lifecycle costs of owning and operating fuel cell cars fueled by hydrogen derived from alternative sources is shown in Figure 4.

The feedstock prices assumed for the construction of Figures 2, 3, and 4 are indicative for the period near 2010 when hydrogen might begin to come into the market in some areas: $3.0/GJ for natural gas, $1.35/GJ for coal, and $2.0/GJ for biomass. The gasoline cost shown in these figures is for reformulated gasoline derived from $23/barrel ($3.75/GJ) crude oil [the world oil price projected for 2010 by the US Department of Energy (EIA, 1995)]. The assumed natural gas price is the average natural gas wellhead price projected for the year 2010 for the US by the US Department of Energy (EIA, 1995), while the coal price is the average price projected for US electric utilities in that year (EIA, 1995). The biomass price is what could be widely realizable for plantation biomass in developing countries in this time frame, based on commercial plantation technology from Brazil;[16] for the industrialized countries, plantation biomass prices based on present technology would be higher. However, if R&D goals for plantation biomass can be realized, biomass prices as low as $1.5/GJ appear to be feasible for the time period near 2020 for large-scale plantation biomass production in the US.[17] It is not likely that biomass would begin to be used for hydrogen production before 2020.

Major Findings of the Sequestration Cost Analysis

The results of the sequestration cost analysis are best understood in the context of the relative costs for energy services for transport using alternative fuel/vehicle combinations, without the sequestration of separated CO_2.

Consider first a comparison of costs without sequestration on a $ per GJ of fuel basis (*see Figure 2*). The first observation one can make about these costs is that gasoline would be far less costly than hydrogen derived from any source. Second, the least costly option for providing hydrogen is from natural gas, for which the cost per GJ to the consumer is likely to be nearly 60 percent higher than the gasoline price. Third, the cost of hydrogen is about the same for both coal and biomass, despite the assumption that the biomass price is about 50 percent higher than the coal price--a reflection of the facts that costly sulfur removal is not needed for biomass and that biomass is more reactive than coal and thus easier to gasify (Williams et al., 1995a; 1995b). Fourth, the cost of hydrogen from biomass or coal is about 10 percent higher than for hydrogen from natural gas. Fifth, all the electrolytic hydrogen options are far more costly than hydrogen derived thermochemically from natural gas, coal, or biomass; for the least costly electrolytic option, which represents what might plausibly be realizable for advanced thin-film photovoltaic technologies,[18] the cost of hydrogen to the consumer is 60 percent higher than the indicated cost of hydrogen from biomass.

A more meaningful comparison than the cost of fuel *per GJ* is the cost of fuel *per km of driving the vehicle* that the fuel might be used in (*see Figure 3*). It is assumed that gasoline is used in an internal combustion engine car with a fuel economy of 11.0 km/l (25.8 mpg) and that hydrogen is used in a fuel cell car of similar performance, for which the estimated gasoline-equivalent fuel economy is 30.4 l/km (71.6 mpg) (Williams, 1995). In this case the cost of hydrogen derived from natural gas and biomass without sequestration of the separated CO_2 would be 1.49 and 1.73 cents/km, respectively, compared to 2.65 cents/km for gasoline.[19,20]

Consider next the penalties for sequestration associated with hydrogen derived from natural gas for the situations depicted in Figure 2. These penalties are low--increasing the cost of hydrogen to the consumer by only 0.8 to 2.6 percent. The low value of the penalty is a result of: (*i*) being able to sequester the separated CO_2 near where it is produced (thus avoiding the costs of long-distance CO_2 pipeline transport), (*ii*) the relatively low penalty for storage in depleted natural gas fields compared to aquifers,[21] and (iii*)* receiving a modest credit for extra natural gas produced as a result of repressurization of the natural gas reservoir--a credit almost large enough to cover the incremental cost of sequestration.

The penalties for sequestration shown in Figure 2 for natural gas feedstocks are for the case where hydrogen is produced at the natural gas field both without and with sequestration. In this case the carbon tax needed to make equal the costs of hydrogen with and without sequestration, and thereby induce hydrogen producers to sequester the separated CO_2, is \$9/tC to \$32/tC, depending on the cost of sequestration and the magnitude of the credit for enhanced natural gas recovery (*see Table 4*). Such a carbon tax would increase the hydrogen cost by \$0.2/GJ to \$0.7/GJ, some 1.6 to 5.5 percent of the cost of hydrogen to consumers without sequestration. The magnitude of the carbon tax in this instance is independent of the length of the hydrogen transmission line and thus would apply equally to situations where large potential hydrogen markets are located near the natural gas field.

If instead hydrogen production without sequestration were to take place 1100 km from the natural gas field near major remote hydrogen markets (*see Table 7*), the hydrogen cost penalty to the consumer for sequestration would increase to the range 3.2 to 5.1 percent, for a natural gas wellhead price of \$3/GJ. In this instance the carbon tax required to make equal the costs of hydrogen produced without and with sequestration is \$39/tC to \$63/tC; with this carbon tax in place the cost of hydrogen to the consumer would be 7 to 11 percent higher than without sequestration and with no carbon tax.[22] Though the impact of this tax on the cost of hydrogen to the consumer is still modest, it is considerably higher than for the scenario where hydrogen production without sequestration takes place near the natural gas field. Since the latter scenario is most realistic for situations where there are large potential hydrogen markets near the natural gas field, the sequestration option is likely to be pursued first in such regions--e.g. in The Netherlands and Texas. If nearby hydrogen markets can be served, there is no need to seek the economies of large-scale hydrogen transmission capacity by building very large hydrogen production plants. This makes it possible to begin sequestration much earlier in the evolution of a hydrogen economy than would be the case if the only potential hydrogen markets were remote from natural gas fields.

For the base case sequestering scenario for coal, in which CO_2 is sequestered in aquifers, the cost penalty is higher--giving rise to a 6 to 11 percent increase in the cost of hydrogen to the consumer for the situations indicated in Figure 2. For the high sequestration cost estimate, the cost of hydrogen to the consumer per km of driving would still be 29 percent less than the cost of gasoline with an internal combustion engine. In this instance, a carbon tax of \$29/tC to \$54/tC would be needed to make equal the costs of hydrogen without and with sequestration, a tax that would increase the cost to the consumer of hydrogen derived from coal by 8 to 15%.

For the base case sequestering scenario for biomass, the cost penalty is somewhat higher but still modest-- giving rise to a 10 to 14 percent increase in the cost of hydrogen to the consumer for the situations indicated in Figure 2. But even if the high sequestration cost estimate proves to be valid, the cost of hydrogen to the consumer per km of driving would still be 26 percent less than the cost of gasoline with an internal combustion engine.

The percentage cost penalties associated with sequestering the separated CO_2 would be smaller still if calculated as a contribution to the total cost of owning and operating a car, to which the cost of fuel makes a relatively modest contribution (*see Figure 4*). Consider, for example, the total lifecycle cost of owning and operating a fuel cell car operated on hydrogen derived from coal without sequestering the separated CO_2. The estimated cost is 20.1 cents/km (slightly less than for a gasoline internal combustion car of comparable performance) for the assumptions indicated in Figure 2, of which the price of hydrogen fuel accounts for only 1.71 cents/km. With a carbon tax sufficient to induce producers of hydrogen from coal to sequester, the lifecycle cost of the car would increase only 0.14 to 0.25 cents/km, or 0.7 to 1.3 percent.

These calculations suggest that deep reductions in CO_2 emissions can be achieved in the transport sector at low incremental cost by shifting to hydrogen or a hydrogen carrier derived from chemical fuel feedstocks. Such cost calculations could of course be refined as more knowledge is gained about the various technologies involved. But this basic finding is robust. It is not sensitive to the outlook for the relative prices of the three feedstocks considered. If natural gas prices remain low for the indefinite future, and if high estimates of remaining ultimately recoverable natural gas resources prove to be valid, hydrogen would be predominately natural gas-based in many parts of the world for decades to come, and sequestration could be pursued on large scales at very low incremental cost. If instead, natural gas prices continue rising rapidly beyond the year 2010,[23] then biomass- and coal-based hydrogen production strategies would eventually supplement hydrogen supplies provided by natural gas.

Biomass without sequestration would tend to be favored over coal with sequestration wherever adequate land resources are available for biomass production,[24] because hydrogen production costs would be as low as or lower under most conditions (for all the cases considered here--*compare Tables 5 and 6*), and because lifecycle emissions would be only half as large (*see Table 1*). However, in regions where coal is cheap and the availability of land for biomass production is limited, coal-based hydrogen strategies would be favored.

Biomass-based production strategies with sequestration would be favored where land-use constraints limit the extent of hydrogen production from biomass and thus drive up biomass costs,[25] where there is interest in achieving deep reductions in emissions at relatively low incremental cost, or when it is desired to offset emissions from other sectors or parts of the world--or some combination of all these considerations.

The largest uncertainties underlying this analysis are: (*i*) the extent to which society will adopt low-temperature fuel cells and their fuels for transportation and distributed cogeneration applications, (*ii*) the prospects for converting existing natural gas transmission lines to hydrogen service and building new pipelines dedicated to hydrogen, and (*iii*) the extent and security of saline aquifers as storage reservoirs for separated CO_2.

Major research, development, and demonstration commitments are needed on the hardware for low-temperature fuel cell technology and for the production, storage, and transport of hydrogen and hydrogen carriers. While there is rapidly growing R&D activity on low-temperature fuel cells for transportation applications, the overall level of the R&D effort in this area is still minuscule. Moreover, there is very little ongoing R&D on the production of hydrogen from coal or biomass.

The issues relating to converting existing natural gas transmission and distribution lines to hydrogen service are discussed in Appendix C. Being able to make this conversion would be especially important for the already industrialized world, where a large natural gas pipeline infrastructure is already in place. It appears to be feasible to convert low-pressure distribution lines without great difficulty, but hydrogen embrittlement looms as a serious issue for high pressure transmission lines. Technical fixes might be possible. For example, would mixing trace quantities of another gas with the hydrogen be a suitable strategy for coping with the embrittlement problem (*see Appendix C*)? More research is needed to find out.

More research is also needed on the various issues raised regarding sequestration in depleted oil and gas fields and saline aquifers--especially the latter. One possible outcome of this research is that saline aquifer storage can be a secure option only for a tiny fraction of the gross aquifer sequestration capacity. If this should turn out to be the case, an alternative of shipping coal or biomass from where it is produced to depleted natural field sites for hydrogen production and sequestration of the separated CO_2 in these depleted natural gas fields might be considered. In the case of coal, the cost of sequestration with this approach would be no more than and perhaps even slightly less than the cost of sequestration in the base case, where CO_2 is piped 250 km to a saline aquifer disposal site (*see Table 5*). This surprising result arises largely because the cost of transporting coal halfway around the world adds only about 6 percent to the cost of hydrogen derived from coal (*see Table 5*). Because of the much lower bulk energy density of biomass, sequestering CO_2 with this option would probably lead to an increase in the cost of hydrogen relative to the case where CO_2 would be sequestered in saline aquifers, but the penalty would probably be small--a 2 to 6 percent increase in production cost for the situation described in Table 6.

Endnotes

[1] The use of coal for power generation in the IS92a scenario accounts for 19 percent of total CO_2 emissions from fossil fuels in 2100, the same percentage as in 1990.

[2] If there were no coal and if those concerned about climate change had only conventional oil and gas resources to worry about, it might be feasible to stabilize the atmospheric concentration of CO_2 near the present level. According to the US Geological Survey (Masters et al., 1994), remaining ultimately recoverable conventional oil and gas resources (proved reserves plus estimated recoverable undiscovered resources) amount (as of 1992) to 11,300 exajoules (EJ) of oil and 12,500 EJ of natural gas. Assuming CO_2 emission coefficients of 19.5 million tonnes of carbon per EJ (MtC/EJ) for oil and 13.5 MtC/EJ for natural gas, cumulative emissions associated with burning all conventional oil and gas resources amount to 390 GtC, which is within the range of cumulative emissions consistent with stabilizing the atmosphere at the present concentration of CO_2 (IPCC, 1994).

[3] Hydrogen produced electrolytically is more costly than hydrogen derived from fuels largely because electricity is far more expensive than fuel per unit of contained energy. Averaged over all users in the US in 1993 the electricity price was three times the price of all petroleum products, five times the price of natural gas, and 14 times the price of coal (EIA, 1995). Hydrogen derived from electricity will be even more expensive than the electricity "feed" used in its manufacture, both because of inefficiencies in electrolytic conversion and because of the capital needed for electrolytic equipment.

While hydrogen derived from carbon-rich fuels via thermochemical processes will be more expensive than these feedstocks per unit of contained energy, it will not be nearly so expensive as electrolytic hydrogen, because the basic processes involved in "turning carbon into hydrogen" (*see Appendix A)* are relatively simple and not nearly so capital-intensive as the process of making electricity.

[4] When hydrogen is derived electrolytically from offpeak power sources that have low running costs, it can be economically attractive, because the capital charges can be avoided. However, the total quantities of hydrogen potentially available via this route are tiny in relation to the demand for fluid fuel. Nevertheless, hydrogen derived electrolytically from offpeak hydroelectric power will play important roles in providing hydrogen for various demonstration projects and other niche applications in helping launch a hydrogen economy.

[5] In 1993 Ballard Power Systems of Vancouver, BC, introduced a 20-passenger, 125 hp, hydrogen PEM fuel-cell "proof-of-concept" bus having a 160-km (100-mile) range. In late 1995, Ballard introduced a 60-passenger, 275 hp, hydrogen PEM fuel cell "commercial prototype" bus having a 400-km (250-mile) range, and the City of Chicago purchased from Ballard three hydrogen fuel cell buses based on this commercial prototype, for delivery in 1996. In 1998 Ballard expects to be producing commercially 75-passenger, 275 hp, hydrogen fuel cell buses having a 560-km (350-mile) range. In April 1994, Daimler-Benz unveiled a proof-of-concept hydrogen PEM fuel cell van based on the use of a Ballard fuel cell and

announced plans to develop PEM fuel cell cars in a joint venture with Ballard.

[6] In one study carried out for the US Department of Energy by the Allison Gas Turbine Division of General Motors (AGTD, 1994) it is estimated that in mass production, the cost for a 60 kW_e continuous output (~ 90 kW_e peak output) automotive electrochemical engine system based on use of the PEM fuel cell operated on methanol would be $3899--consisting of $1752 for the fuel cell stack, plus $1077 for the fuel processor, $195 for the heat rejection and water management system, and $875 for system auxiliaries--so that the total unit installed cost would be $65/$kW_e$ continuous ($46/$kW_e$ peak).

In another study carried out for the US Department of Energy by Directed Technologies, Inc. (James et al., 1994), the cost of mass-produced automotive hydrogen/air PEM fuel cells (for production at a rate of 10^6 units per year in the year 2004) is estimated to be $31/$kW_e$, and the cost of an 85 kW_e hydrogen/air PEM fuel-cell based automotive power system (including the cost of the fuel cell, the heat management system, the power conditioning, an ultracapacitor for peak power, an electric motor, and storage tanks for compressed hydrogen) is estimated to be $4,400 to $5,100, compared to $3,000 to $4,000 for the cost of the internal combustion engine equipment that would be displaced.

[7] At the site, or, in transport applications, onboard the vehicle, methanol is "reformed" to produce a gaseous mixture of hydrogen and carbon dioxide via reactions that are summarized as:

$$CH_3OH + H_2O_{(g)} \text{ -----> } CO_2 + 3H_2.$$

This gaseous fuel mixture can be utilized directly by proton-exchange membrane fuel cells, which (unlike the alkaline fuel cells used in the space program) are not poisoned by CO_2.

[8] Hydrogen and methanol can be produced from natural gas with commercially available technology. These energy carriers can also be produced from coal using commercially ready oxygen-blown coal gasifiers plus commercially available technologies for the needed further processing. In the case of biomass, the fuel processing technologies downstream of the gasifier are also commercially available. While suitable gasifiers tailored to biomass are not commercially available, such gasifiers could be commercially available by 2000 with a relatively modest RD&D effort (Williams et al., 1995a; 1995b).

[9] When hydrogen is produced from natural gas, the carbon content of the natural gas feedstock amounts to 15.2 kg C per GJ of produced hydrogen, while the CO_2 stream separated at the PSA unit has a carbon content of 10.7 kg C per GJ of produced hydrogen. When hydrogen is produced from coal, the carbon content of the coal feedstock amounts to 31.8 kg C per GJ of produced hydrogen, while the CO_2 stream separated at the PSA unit has a carbon content of 29.8 kg C per GJ of produced hydrogen.

[10] When hydrogen is produced from biomass, the carbon content of the biomass feedstock amounts to 34.4 kg C per GJ of produced hydrogen, while the CO_2 stream separated

at the PSA unit has a carbon content of 23.8 kg C per GJ of produced hydrogen.

[11] In this paper all costs are presented in 1991$ and lifecycle costs are evaluated using a 10 percent real (inflation-corrected) discount rate. Corporate income, property, and sales taxes are neglected. Also, the energy content of fuels is given in terms of the higher heating value.

[12] The present analysis is limited to hydrogen because the sequestration potential is much larger than for methanol production (*see Table 1*). However, the general finding that sequestration costs are low holds for methanol as well. In fact, the costs for CO_2 compression would be less with methanol production. In this case, the CO_2 is generally released at higher pressures using Selexol CO_2 separation technology [e.g., 13 bar for methanol produced from biomass using the Battelle Columbus Laboratory biomass gasifier and 21.8 bar for methanol produced from coal using the Shell gasifier (Katofsky, 1993)] than is the case for the PSA technology used in hydrogen production (1.3 bar). If the CO_2 must be compressed to 110 bar, the required compression ratio is just 8.5 for biomass- and 5.0 for coal-derived methanol, compared to 85 for hydrogen produced from natural gas, coal, or biomass.

[13] The costs for drying and compressing CO_2 to the pressures needed for pipeline transport and reservoir injection are based on Farla et al. (1992) at Utrecht University--see note d, Table 4.

[14] The costs of CO_2 transport by pipeline are based on analyses carried out at the Statoil R&D Centre in Trondheim, Norway (Skovholt, 1993)--see note h, Tables 5 and 6.

[15] The costs for disposal in both depleted natural gas fields and saline aquifers are based on the work of Hendriks (1994) at Utrecht University--see note e, Table 4, and note i, Tables 5 and 6.

[16] Drawing on commercial plantation experience in Brazil (Carpentieri et al., 1993), biomass supply curves (potential production vs. long-run marginal production cost) have been generated on a country-by-country basis for Africa, Latin America, and Asia, for the year 2025, taking into account land requirements for food production at that time (Larson et al., 1995). Marginal costs were related to prospective yields, and prospective yields were estimated via a correlation with rainfall. It was found that 70 EJ/year (35 EJ/year) of biomass could be produced on 10 percent (5 percent) of "available" land in those countries where biomass can be produced at or below this cost. Available land is defined here as non-forest, non-wilderness land that is not needed for producing food crops. To put these energy quantities into perspective, consumption of coal, oil, and natural gas in 1990 were 35.8 EJ, 40.5 EJ, and 12.2 EJ, respectively, for developing countries.

[17] In a major assessment carried out by a team with participants from the Oak Ridge National Laboratory and the US Department of Agriculture it is estimated that if R&D goals for plantation biomass in the US can be realized, 5 EJ/year of plantation biomass could be produced in 2020 on 17 million hectares at a long-run marginal of $1.5/GJ (Graham et al., 1995). For comparison, about 3 EJ/year of biomass would be required to support a fleet of

120 million cars (the total number in the US in 1992) powered by hydrogen fuel cells, assuming the gasoline-equivalent fuel economy of these fuel cell cars is 34 km/l (80 mpg).

[18] The least costly electrolytic option is for a photovoltaic (pv) module efficiency of 18 percent, a pv installed system cost of $1030/kW, and a plant siting in an area of high insolation (270 W/m^2). These pv performance and cost parameters are optimistic but plausible for advanced thin-film pv technologies (Ogden and Nitsch, 1993).

[19] Initially fuel cell cars would probably be operated on gasoline converted to a hydrogen-rich gaseous fuel mixture via a process that begins with partial oxidation. The estimated fuel economy of such a fuel cell car having the same performance as the internal combustion engine alternative would be 18.0 km/l (42.3 mpg). The fuel cost per km for this vehicle would be 1.62 cents/km.

[20] With a cost of service comparison, even costs for electrolytic hydrogen used in fuel cell vehicles are not much different from the 2.65 cent per km cost of gasoline for an internal combustion engine vehicle--ranging from 2.75 to 3.90 cents per km for the electrolytic options shown in Figure 3.

[21] Storage costs estimated by Hendriks (1994) range from $3/tC to $13/tC for depleted natural gas fields, compared to $9/tC to $34/tC for saline aquifers.

[22] For comparison, a carbon tax in the range $39/tC to $63/tC would increase the retail price of gasoline shown in Figure 2 by 11 to 17 percent.

[23] The US Department of Energy has projected that the wellhead price of natural gas in the US will increase at an annual average rate of 3.1 percent per year, 1993-2010 (EIA, 1995).

[24] Considerable hydrogen production from biomass is likely to be possible before land scarcity becomes a major limiting factor for the growing of biomass. See, for example, the calculation presented in Appendix B, and discussions of land use availability for industrialized countries in Williams (1994a) and for developing countries in Larson et al. (1995).

[25] With sequestration of the separated CO_2, the amount of biomass grown on a given land area could make a much larger contribution in reducing global emissions than without sequestration.

Appendix A: The Importance of the Water-Gas-Shift Reaction In Fuel Decarbonization

It is feasible to convert a carbon-rich fuel to a hydrogen-rich fuel at relatively high overall efficiency by taking advantage of the thermodynamics of the so-called water-gas-shift reaction.

Suppose it is desired to make hydrogen (H_2) out of carbon (C). The first step is to gasify C by partial oxidation to produce carbon monoxide (CO):

$$C + 1/2\ O_2 \text{ -----> } CO, \quad \underline{\Delta}\, H_R = -\ 110.5 \text{ MJ/mol.}$$

Note that with complete oxidation,

$$C + O_2 \text{ -----> } CO_2, \quad \underline{\Delta}\, H_R = -\ 393.5 \text{ MJ/mol,}$$

which shows that the CO produced in partial oxidation retains 71.9% of the higher heating value (HHV) of the original C:

$$HHV_{CO} = 283.0 \text{ MJ/mol,}$$
$$HHV_{C} = 393.5 \text{ MJ/mol.}$$

The HHV of H_2 is approximately the same as the HHV of CO:

$$HHV_{H2} = 285.8 \text{ MJ/mol.}$$

The next step is to use the water-gas-shift reaction:

$$CO + H_2O_{(g)} \text{ ------> } CO_2 + H_2, \quad \underline{\Delta}\, H_R = -\ 41.2 \text{ MJ/mol,}$$

a slightly exothermic reaction that makes it possible to "shift" the energy contained in the CO to H_2. The needed steam (gaseous water, $H_2O_{(g)}$) can be raised by evaporating liquid water ($H_2O_{(l)}$), a phase change that requires just slightly more heat than is generated in the water-gas-shift reaction:

$$H_2O_{(l)} \text{ ------> } H_2O_{(g)}, \quad \underline{\Delta}\, H_{PC} = +\ 44.0 \text{ MJ/mol.}$$

Note that the extra heat required (44.0 - 41.2 = 2.8 MJ/mol) can be met using just 2.5% of the heat released via the initial partial oxidation of C.

The final step in the production of H_2 from C involves separating out the H_2 from the gaseous H_2/CO_2 mixture--for example, using commercial pressure swing adsorption (PSA) technology that can recover 90% or more of the produced H_2 at up to 99.999% purity. (PSA exploits the ability of porous materials to selectively adsorb specific molecules at high pressure and desorb them at low pressure; the cyclic pressure *swing* is what gives the process its name.) A "free" byproduct of the process is a stream of pure CO_2 that is potentially available for sequestration in some secure reservoir.

This discussion shows that it is possible in theory to generate 1 mole of H_2 from 1 mole of C at an overall efficiency n = 100*(285.8/393.5) = 72.6%. In the real world, H_2 fuel would be made from natural gas, coal, or biomass. H_2 can be produced from natural gas at an overall real-world efficiency of 84% via a process that begins by reacting natural gas with steam (Williams, et al., 1995a; 1995b). This efficiency is higher than for making H_2 from C because natural gas (mainly methane, CH_4) already contains a great deal of H_2. The real-world efficiencies for making H_2 from coal (whose chemical composition can be represented as ~ $CH_{0.8}O_{0.08}$) via oxygen-blown gasification and from biomass (whose chemical composition can be represented as ~ $CH_{1.5}O_{0.7}$) via steam oxidation are each about 64% (Williams et al., 1995a; 1995b).

Appendix B: Biomass CO_2 Emission Offset Potential in a World Where Some Coal-Rich Regions Cannot or Will Not Reduce Emissions

Consider a world situation in 2100 where the hydrogen fuel cell vehicle is a well established technology and where natural gas resources are in limited supply, so that the primary options for producing hydrogen at low cost are from coal and biomass. Suppose further that some regions with a capacity to produce biomass on large scales agree to seek to help bring about deep reductions in global CO_2 emissions, but that other regions must depend on coal and either have no ready access to secure sequestering sites or are unwilling to incur the cost penalties for storage, however modest. Under these circumstances it may still be feasible to achieve low global emissions levels because of the large "emissions offset potential" offered by biomass-derived hydrogen (*see Tables 1 and 2*).

To illustrate the possibilities, suppose that: (*i*) the world population in 2100 is 10.5 billion; (*ii*) there are then 0.4 cars per capita in the world (the average for the industrialized market countries in 1985)--some 4.2 billion cars altogether (10 times the present number); (*iii*) the average car is driven 13,400 km/year (the average for industrialized market countries in 1985); (*iv*) these cars are all equipped with hydrogen fuel cells; (*v*) the average automotive fuel economy is 42.5 km/liter (100 mpg) of gasoline-equivalent.

With so many cars, would it be possible to have zero net CO_2 emissions worldwide from the automotive sector, if some cars were run on hydrogen derived from coal without sequestration of the separated CO_2 (so that net lifecycle emissions would be + 41.2 kg C/GJ of hydrogen--*see Table 1*) and if the rest were run on hydrogen derived from biomass with sequestration of the separated CO_2 in saline aquifers and/or depleted natural fields (so that the net lifecycle emissions would be - 18.4 kg C/GJ of hydrogen--*see Table 1*)?

Under the above conditions, there would be zero net emissions from the automotive sector if a fraction "a" of all cars is operated on coal-derived hydrogen, where "a" is determined from the following equation based on the net lifecycle emission rates for the two hydrogen-producing systems: $41.2*a - (1 - a)*18.4 = 0$, or $a = 0.31$. Thus net global emissions from cars would be zero if 31% of the hydrogen were derived from coal and 69% from biomass. The amount of hydrogen consumed worldwide for cars would be 46 EJ per year. Assuming an efficiency of 64% for making hydrogen from coal or biomass (*see Appendix A*), some 22 EJ and 51 EJ per year of coal and biomass, respectively would be needed for fueling automobiles in 2100. For comparison, total global coal consumption in 1985 was 90 EJ per year; and 50 EJ per year is approximately the average rate at which noncommercial biomass is consumed in the world today (Hall et al., 1993). Assume that in 2100 all this biomass would be grown on plantations. It is reasonable to expect an average yield of, say, 20 dry tonnes per hectare per year at that time (Williams, 1995). With an energy content of 20 GJ/dry tonne, some 128 million hectares of plantation area would be needed worldwide. There will very likely be far more land available for biomass energy plantations than this (Larson et al., 1995). The required sequestering rate of 0.75 Gt C per year is modest in relation to the estimated capacities of aquifers and depleted natural gas and oil fields.

Appendix C: Pipeline Transport of Hydrogen

Transport costs for new pipelines. The cost of hydrogen pipeline transport is higher than for natural gas. Pottier et al. (1988) estimate that the cost of the pipe would typically be 50% higher than for natural gas transmission lines, largely because embrittlement-resistant steels would be specified. Also, the optimized pipe diameter would be perhaps 20% larger for hydrogen to achieve the same energy flow rate (Leeth, 1979). The cost of installation would also be higher, since special care would be needed with welds. And much larger compressors would be needed to achieve the same energy flow rates, since the volumetric energy density of hydrogen is just 35% of that for natural gas.

But hydrogen pipeline transport costs would not be prohibitive, for two reasons. First, the diversity of supply options implies that hydrogen would often be available from sources that are relatively close to where the hydrogen is needed (Ogden and Nitsch, 1993). Second, even where long-distance pipelines are needed, the costs involved are relatively modest compared to the total cost of hydrogen to the consumer, and the total cost per unit of service provided would typically still be less than for conventional transport fuels. For example, the transport of hydrogen 1110 km to consumers for use in fuel cell vehicles from a production facility located at a natural gas field contributes less than 1/5 of the total cost of hydrogen to the consumer (*see Figure 2 and Table 7*).

Transport costs for pipelines converted to hydrogen from natural gas. In many parts of the industrialized world extensive pipeline networks designed for use with natural gas are already in place. Could these pipelines be converted to hydrogen? Even neglecting considerations of embrittlement, these pipelines are not optimized for use with hydrogen, whose energy density and viscosity are very different from the values for natural gas. Nevertheless, from a fluid dynamics perspective, the mismatch would not be severe. For a given pipe diameter and operating pressure, the energy flow rate for hydrogen would be about 85% of that for natural gas with partially turbulent flow and 90% of that for natural gas with fully turbulent flow (Christodoulou, 1984). Seals, joints, and metering equipment would probably have to be replaced with conversion. Moreover, almost three times as much compressor power would be needed to obtain the same energy flow rate as for natural gas; and reciprocating rather than centrifugal compressors would be needed. Nevertheless, there could be large savings associated with the sunk costs of the pipelines themselves, if conversion were feasible.

Hydrogen embrittlement. A major concern about converting natural gas pipelines to hydrogen service is "hydrogen environment embrittlement," which refers to the degradation of mechanical properties that takes place when a metal is exposed to a hydrogen environment. The available evidence indicates that this is not an issue for existing local natural gas distribution systems, which could therefore be converted to hydrogen with only minor modifications (Ogden et al., 1995). However, because of the higher pressures (up to 70 bar or 1000 psia) and materials used, hydrogen environment embrittlement could be a serious problem for existing long-distance natural gas transmission lines that would transport pure hydrogen. The primary mechanisms are fatigue crack growth under cyclic loading and slow crack growth under stable loads near welds and other "heat-affected" zones in pipes.

Various countermeasures have been suggested, including adding gases to inhibit embrittlement, preloading with an inert gas, coating pipelines, and selective replacement of steels susceptible to embrittlement. The most promising approach seems to be gas additives. Available research indicates strong inhibition of fatigue crack growth with oxygen, at concentrations ranging from 100 ppm to 1% (Ogden et al., 1995). A high priority for hydrogen research should be given to gas additives and other countermeasures for inhibiting embrittlement in existing natural gas transmission lines that might be converted to hydrogen.

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Table 1. CO_2 Emissions Characteristics of Alternative Transport Fuel Options *(kg C/GJ of Transport Fuel Produced)*

Fuel Option	Lifecycle CO_2 Generation Rate[a]	Photosynthetic Offset[b]	Potential CO_2 Sequestration Rate[c]	Net Lifecycle Emissions with Photosynthetic Offset and/or CO_2 Sequestration
Reformulated Gasoline	22.6	-	-	22.6
MeOH from Natural Gas	23.0	-	-[d]	23.0
H_2 from Natural Gas w/o CO_2 Sequestering	21.8	-	-10.7	21.8
H_2 from Natural Gas w/CO_2 Sequestering	21.8	-	-10.7	11.1
MeOH from Coal w/o CO_2 Sequestering	40.8	-	-18.6	40.8
MeOH from Coal w/CO_2 Sequestering	40.8	-	-18.6	22.3
H_2 from Coal w/o CO_2 Sequestering	41.2	-	-29.8	41.2
H_2 from Coal w/CO_2 Sequestering	41.2	-	-29.8	11.4
MeOH from Biomass w/o CO_2 Sequestering	42.8	-40.5	-11.1	2.3
MeOH from Biomass w/CO_2 Sequestering	42.8	-40.5	-11.1	-8.8
H_2 from Biomass w/o CO_2 Sequestering	38.9	-33.5	-23.8	5.4
H_2 from Biomass w/CO_2 Sequestering	38.9	-33.5	-23.8	-18.4

Notes for Table 1

[a] Williams et al. (1995a; 1995b) provide estimates of emissions of CO_2 that occur throughout the entire cycle of fuel production, fuel transport, additional processing (if any), and final use for the primary energy source/energy carrier combinations shown here, in gr C per km, for internal combustion engine vehicle and fuel cell vehicle applications. Lifecycle emissions per km of travel are converted here to emissions per GJ of energy carrier consumed by taking into account the fuel economy of the vehicle (see footnote b to Table 2).

[b] This is the CO_2 extracted from the atmosphere in growing biomass. It is not quite as large as the lifecycle emissions associated with the production of H_2 or MeOH from biomass, because of the various fossil fuel inputs involved in biomass production--e.g., for cultivation, harvesting, and hauling equipment, and for fertilizers and herbicides.

[c] This is the C in the pure CO_2 stream produced at the fuel production facility as a "free" byproduct of the production of H_2 or MeOH (from Katofsky, 1993).

[d] There is no CO_2 recovery at plants producing methanol from natural gas, because fuel processing does not involve the water-gas shift reaction (*see Appendix A*); the H/C ratio needed for methanol is the same as that for methane, the principal constituent of natural gas.

Table 2. Net Lifecycle CO_2 Emissions with Photosynthetic Offsets and/or CO_2 Sequestration for Alternative Transport Fuel Options

Fuel Option	Emissions per Unit of Transport Fuel Provided[a] *(kg C/GJ)*	Emissions per Unit of Transport ServiceProvided[b] *[gr C/km of car driving--ICEV (FCV)]*
Reformulated Gasoline	22.6	71.6 (38.7)
MeOH from Natural Gas	23.0	64.9 (30.7)
H_2 from Natural Gas w/o CO_2 Sequestering	21.8	59.9 (25.0)
H_2 from Natural Gas w/CO_2 Sequestering	11.1	30.5 (12.7)
MeOH from Coal w/o CO_2 Sequestering	40.8	115.1 (54.5)
MeOH from Coal w/CO_2 Sequestering	22.3	62.9 (29.8)
H_2 from Coal w/o CO_2 Sequestering	41.2	113.0 (47.2)
H_2 from Coal w/CO_2 Sequestering	11.4	31.3 (13.1)
MeOH from Biomass w/o CO_2 Sequestering	2.3	6.6 (3.1)
MeOH from Biomass w/CO_2 Sequestering	-8.8	-25.3 (-11.9)
H_2 from Biomass w/o CO_2 Sequestering	5.4	14.7 (6.1)
H_2 from Biomass w/CO_2 Sequestering	-18.4	-50.1 (-20.7)

Notes for Table 2

[a] From Table 1 (right-most column).

[b] Net lifecycle emissions E_{km} (in gr C per km of driving) are obtained from net lifecycle emissions E_{GJ} (kg C per GJ) of the energy carrier via

$$E_{km} = (1000 \text{ gr/kg})*(0.0348 \text{ GJ/liter})*E_{GJ}/FE,$$

where FE is the fuel economy of the vehicle, in km/liter of gasoline equivalent. [Gasoline has a higher heating value (HHV) of 0.0348 GJ/liter.] Emissions E_{km} are given both for internal combustion engine vehicles (ICEVs) and for fuel cell vehicles (FCVs). For ICEVs, the gasoline-equivalent fuel economies are assumed to be: for gasoline,11.0 km/l (25.8 mpg); for MeOH, 12.4 km/l (29.1 mpg); and for H_2, 12.7 km/l (29.9 mpg). For FCVs, the gasoline-equivalent fuel economies are assumed to be: for gasoline, 20.4 km/l (47.7 mpg), based on the use of onboard partial oxidation; for MeOH, 26.1 km/l (61.5 mpg), based on the use of an onboard steam reformer; and for compressed H_2 gas, 30.4 km/l (71.6 mpg). See Williams et al. (1995a; 1995b).

Table 3a. Areas of Sedimentary Basins in Relation to Total Land Areas

Region	Total Land Area [10^6 km^2]	Area of Sedimentary Basins[a] [10^6 km^2 (% of Total Land Area)]
Asia	27.6	11.34 (41%)
Former USSR	22.4	9.71 (43%)
Europe	4.93	2.76 (56%)
South America	17.8	9.07 (51%)
North America	24.2	9.21 (38%)
Africa	30.3	15.23 (50%)
Australia and Oceania	8.51	7.47 (88%)
World	135.7	64.79 (48%)

[a] Source: (Koide et al., 1992).

Table 3b. Order-of-Magnitude Estimates of the CO_2 Storage Capacity of Aquifers[a] *(GtC)*

Region	Structural Trap Required	No Structural Trap Required
Western Europe	3	700
Eastern Europe	8	2000
North America	11	2700
Latin America	11	2700
Africa	11	2700
Middle East	3	700
Oceania and Asia	14	3400
World	60	15,000

[a] Source: (Hendriks et al., 1994).

Table 4. Cost of Producing Hydrogen from NG Near Depleted NG Fields (*\$/GJ of H_2*)

Cost Component	Venting of Recovered CO_2[a]	Sequestration of Recovered CO_2 in Depleted NG Field[a]			
		High Credit for Enhanced NG Recovery		Low Credit for Enhanced NG Recovery	
		Low-Cost Sequestration	High-Cost Sequestration	Low-Cost Sequestration	High-Cost Sequestration
Base H_2 Plant Costs[b]					
Capital	1.36	1.36	1.36	1.36	1.36
Labor, Maintenance	0.61	0.61	0.61	0.61	0.61
Purchased Energy	0.41	0.41	0.41	0.41	0.41
Feedstock	$1.115*P_{ng}$	$1.115*P_{ng}$	$1.115*P_{ng}$	$1.115*P_{ng}$	$1.115*P_{ng}$
Credit for Enhanced NG Recovery[c]	-	$- 0.079*P_{ng}$	$- 0.079*P_{ng}$	$- 0.033*P_{ng}$	$- 0.033*P_{ng}$
CO_2 Compression/Drying[d]					
Capital	-	0.06	0.06	0.06	0.06
O&M	-	0.02	0.02	0.02	0.02
Electricity	-	0.22	0.22	0.22	0.22
Subtotal	-	0.30	0.30	0.30	0.30
CO_2 Storage[e]	-	0.03	0.14	0.03	0.14
Total	$2.38 + 1.115*P_{ng}$	$2.71 + 1.036*P_{ng}$	$2.82 + 1.036*P_{ng}$	$2.71 + 1.082*P_{ng}$	$2.82 + 1.082*P_{ng}$

Notes for Table 4

[a] Lifecycle emissions are 21.8 kg C/GJ of H_2 with venting of the separated CO_2 and 11.1 kg C/GJ if the separated CO_2 is sequestered. See Table 1.

[b] For a plant producing 19.1 PJ/year of H_2 @ 75 bar via steam reforming. The overnight construction cost is \$188.3 million; land + working capital are \$18.2 million; external electricity requirements are 8.2 kWh/GJ of H_2 (Williams et al., 1995a; 1995b). Assuming a 3-year construction period, a 25-year plant life, and an annual insurance charge of 0.5%, the annual fixed capital charge rate is 0.1277, while the annual capital charge rate for land + working capital is 0.10. It is assumed that the purchased electricity price is \$0.05/kWh. Here P_{ng} is the price of natural gas (NG) feedstock, in \$/GJ.

[c] Following Blok et al. (1995), it is assumed that the extra NG available from repressurizing the reservoir via CO_2 injection is 3.5-8.5% of total NG requirements averaged over a 15-year period after primary NG production ceases; the values of enhanced production levelized over the 25-year life of the plant is 2.9-7.1% of NG feedstock needs.

[d] CO_2 is produced at the H_2 plant in a 750,000 tonnes/year stream at 1.3 bar and 40 °C, with 1.5% moisture (Katofsky, 1993). It is assumed that the CO_2 must be dried to less than 10 ppm and compressed to 110 bar (Farla et al., 1992). The capital cost CC = $\$10.35*10^6$ US\$),

Notes for Table 4, continued

from CC = $0.351*(CAP)^{0.51117}$ (Farla et al., 1992), where CAP is the capacity (in 10^3 tonnes of CO_2/year). Assuming a 1-year construction period, a 25-year plant life and an insurance charge of 0.5%/year, the annual capital charge rate is 0.1172. It is assumed that annual O&M costs are 3.5% of the capital cost. In this capacity range, electricity requirements EL (in kWh/tC) are given by EL = $1097.5*(CAP)^{-0.1509}$ (Farla et al., 1992), or 404 kWh/tC.

[e] For injection into depleted NG fields at a depth of 2 km, Hendriks (1994) has calculated that storage costs range from \$2.6-\$13.3/tC for injection rates of 20-2 Nm^3/s.

Table 5. Cost of Producing Hydrogen from Coal (*$/GJ of H_2*)

	Venting of Recovered CO_2[a]	Coal Transported to Depleted NG Field for H_2 Production. Sequestration of Recovered CO_2 in Depleted NG Field[a]		Sequestration of Recovered CO_2 in Aquifer 250 km from H_2 Production Plant[a]	
		Low-Cost Sequestration	High-Cost Sequestration	Low-Cost Sequestration	High-Cost Sequestration
Base H_2 Plant Costs[b]					
Capital	3.48	3.48	3.48	3.48	3.48
Labor, Maintenance	1.36	1.36	1.36	1.36	1.36
Purchased Energy	1.51	1.51	1.51	1.51	1.51
Feedstock	$1.292*P_c$	$1.292*P_c$	$1.292*P_c$	$1.292*P_c$	$1.292*P_c$
CO_2 Drying[c]	-	-[d]	-[d]	0.02	0.02
CO_2 Compression/Drying[e]	-	0.28	0.28	-[f]	-[f]
Coal Transport[g] or CO_2 Pipeline[h]	-	0.55	0.55	0.60	0.60
CO_2 Storage[i]	-	0.08	0.40	0.28	1.02
Total	$6.35 + 1.292*P_c$	$7.26 + 1.292*P_c$	$7.58 + 1.292*P_c$	$7.23 + 1.292*P_c$	$7.97 + 1.292*P_c$

Notes for Table 5

[a] Lifecycle emissions are 41.2 kg C/GJ of H_2 with venting of the separated CO_2 and 11.4 kg C/GJ if the separated CO_2 is sequestered. See Table 1.

[b] For a plant producing 37.8 PJ/year of H_2 @ 75 bar using a Shell oxygen-blown gasifier, for which the overnight construction cost is $924.4 million; land + working capital are $78.2 million; external electricity requirements are 27.8 kWh/GJ of H_2 (Williams et al., 1995a; 1995b). Assuming a 4-year construction period, a 25-year plant life, and an annual insurance charge of 0.5%, the annual fixed capital charge rate is 0.1337, while the annual capital charge rate for land + working capital is 0.10. It is assumed that the purchased electricity price is $0.05/kWh. Here P_c is the price of the coal feedstock, in $/GJ.

[c] From Farla et al. (1992) the cost of drying the CO_2 to < 10 ppm is $0.073/tC for steam (@ 8 MJ/tonne of CO_2) plus $0.416/tC for capital [for a capital cost $CC = 1.48*(CAP)^{0.7}$ = $3.99 million when CAP = CO_2 recovery rate = $4.125*10^6$ tonnes/year of CO_2; assuming a 25-year plant life and an annual insurance charge of 0.5%/year, the annual capital charge rate is 0.1172] plus an

Notes for Table 5, continued

annual O&M cost of 2.1% of the capital cost per year or \$0.074/tC. Thus the total cost of drying is \$0.563/tC or \$0.017/GJ of produced H_2.

[d] Included in CO_2 compression/drying charges.

[e] Following the procedure outlined in note d, Table 4, the capital cost for compression/drying CO_2 recovered at a rate of $4.125*10^6$ tonnes/year is $\$24.74*10^6$, corresponding to a capital charge of \$0.077/GJ and an O&M charge of \$0.023/GJ. Likewise, the electricity requirements for compression are 313 kWh/tC, for which the charge is \$0.178/GJ.

[f] Included in CO_2 drying and CO_2 pipeline costs.

[g] The cost of transporting coal from where it is produced to a depleted NG field site for a hydrogen production facility is taken to be \$0.35/GJ, the difference between the import price of Australian coal (with a higher heating value of 27.2 GJ/tonne) imported into Europe and its export price from Australia in 1993 (IEA, 1995). This translates into a cost penalty of \$0.55/GJ of produced hydrogen.

[h] Skovholt (1993) has calculated the pipeline cost PC, in \$/tC (including costs of compression of CO_2 from atmospheric pressure to 110 bar) for 250 km of pipeline transmission of CO_2, for pipelines of capacities of 3 to 100 million tonnes of CO_2/year. A regression yields $PC = 43.85*(CAP)^{-0.54786}$, where CAP is the capacity in million tonnes of CO_2/year. For a plant with CAP = 4.125 million tonnes of CO_2 per year, PC = \$20.18/tC or \$0.60/GJ of H_2.

[i] For injection into saline aquifers (depleted NG fields) at a depth of 2 km, Hendriks (1994) has calculated the storage cost to range from \$9.2/tC (\$2.6/tC) for an injection rate of 20 Nm^3/s to \$34.3/tC (\$13.3/tC)for an injection rate of 2 Nm^3/s.

Table 6. Cost of Producing Hydrogen from Biomass (*\$/GJ of H_2*)

	Venting of Recovered CO_2[a]	Biomass Transported to Depleted NG Field for H_2 Production. Sequestration of Recovered CO_2 in Depleted NG Field[a]		Sequestration of Recovered CO_2 in Aquifer 250 km from H_2 Production Plant[a]	
		Low-Cost Sequestration	High-Cost Sequestration	Low-Cost Sequestration	High-Cost Sequestration
Base H_2 Plant Costs[b]					
Capital	2.87	2.87	2.87	2.87	2.87
Labor, Maintenance	1.39	1.39	1.39	1.39	1.39
Purchased Energy	1.09	1.09	1.09	1.09	1.09
Feedstock	$1.366*P_b$	$1.366*P_b$	$1.366*P_b$	$1.366*P_b$	$1.366*P_b$
CO_2 Drying[c]	-	-[d]	-[d]	0.02	0.02
CO_2 Compression/Drying[e]	-	0.57	0.57	-[f]	-[f]
Biomass Transport[g] or CO_2 Pipeline[h]	-	1.48	1.48	1.30	1.30
CO_2 Storage[i]	-	0.06	0.32	0.22	0.82
Total	$5.35 + 1.366*P_b$	$7.46 + 1.366*P_b$	$7.72 + 1.366*P_b$	$6.89 + 1.366*P_b$	$7.49 + 1.366*P_b$

Notes for Table 6

[a] Lifecycle emissions are + 5.4 kg C/GJ of H_2 with venting of the separated CO_2 and - 18.4 kg C/GJ if the separated CO_2 is sequestered. See Table 1.

[b] For a plant producing 7.73 PJ/year of H_2 @ 75 bar using a Battelle Columbus Laboratory indirectly heated biomass gasifier, for which the overnight construction cost is \$170.3 million; land + working capital are \$14.7 million; external electricity requirements are 21.7 kWh/GJ of H_2 (Williams et al., 1995a; 1995b). Assuming a 2-year construction period, a 25-year plant life, and an annual insurance charge of 0.5%, the annual fixed capital charge rate is 0.1215, while the annual capital charge rate for land + working capital is 0.10. It is assumed that the purchased electricity price is \$0.05/kWh. Here P_b is the price of the biomass feedstock, in \$/GJ.

[c] From Farla et al. (1992) the cost of drying the CO_2 to < 10 ppm is \$0.073/tC for steam (@ 8 MJ/tonne of CO_2) plus \$0.714/tC for capital [for a capital cost $CC = 1.48*(CAP)^{0.7}$ = \$1.12 million when CAP = CO_2 recovery rate = $0.674*10^6$ tonnes/year of CO_2; assuming a 25-year plant life and an annual insurance charge of 0.5%/year, the annual capital charge rate is 0.1172] plus an

Notes for Table 6, continued

annual O&M cost of 2.1% of the capital cost per year or \$0.128/tC. Thus the total cost of drying is \$0.915/tC or \$0.022/GJ of produced H_2.

[d] Included in CO_2 compression/drying charges.

[e] Following the procedure outlined in note d, Table 4, the capital cost for compression/drying CO_2 recovered at a rate of $0.674*10^6$ tonnes/year is $\$9.8*10^6$, corresponding to a capital charge of \$0.149/GJ and an O&M charge of \$0.044/GJ. Likewise, the electricity requirements for compression are 411 kWh/tC, for which the charge is \$0.378/GJ.

[f] Included in CO_2 drying and CO_2 pipeline costs.

[g] Assuming that wet biomass has a higher heating value of 10 GJ/tonne and that the cost of transporting biomass or coal from where it is produced to a hydrogen production facility at a depleted NG field site, the cost for biomass would be 2.7 times the cost for Australian coal or \$0.94/GJ if the benchmark for coal is as assumed in note g, Table 5. This translates into a cost penalty of \$1.48/GJ of produced hydrogen.

[h] Following the approach outlined in note h, Table 5, the pipeline cost PC, in \$/tC for 250 km of pipeline transmission of CO_2 $PC = 43.85*(CAP)^{-0.54786} = \$54.44/tC$ or \$1.30/GJ of produced hydrogen, for CAP = 0.674 million tonnes of CO_2/year.

[i] For injection into saline aquifers (depleted NG fields) at a depth of 2 km, Hendriks (1994) has calculated the storage cost to range from \$9.2/tC (\$2.6/tC) for an injection rate of 20 Nm^3/s to \$34.3/tC (\$13.3/tC) for an injection rate of 2 Nm^3/s.

Table 7. Delivered Costs of Hydrogen Produced from Alternative Feedstocks[a]
($/GJ of H_2)

Cost Component	H_2 from Natural Gas			H_2 from Coal[d]		H_2 from Biomass[e]	
	w/o CO_2 Sequestration, H_2 Plant at the NG Field[b]	w/o CO_2 Sequestration, H_2 Plant at the City Gate[c]	w/CO_2 Sequestration, H_2 Plant at the NG Field[b]	w/o CO_2 Sequestration	w/CO_2 Sequestration	w/o CO_2 Sequestration	w/CO_2 Sequestration
Production	$2.38 + 1.115*P_{ng}$	$2.67 + 1.115*P_{ng}$	$2.77 + 1.059*P_{ng}$	$6.35 + 1.292*P_c$	$7.60 + 1.292*P_c$	$5.35 + 1.366*P_b$	$7.19 + 1.366*P_b$
H_2 Pipeline T&D[f]							
1000 km pipeline	0.50	-	0.50	-	-	-	-
100 km pipeline	0.10	-	0.10	0.05	0.05	0.24	0.24
10 km pipeline	1.69	1.69	1.69	1.69	1.69	1.69	1.69
Subtotal	2.29	1.69	2.29	1.74	1.74	1.93	1.93
Refueling[g]	5.07	5.07	5.07	5.07	5.07	5.07	5.07
Total	$9.74 + 1.115*P_{ng}$	$9.43 + 1.115*P_{ng}$	$10.13 + 1.059*P_{ng}$	$13.16 + 1.292*P_c$	$14.41 + 1.292*P_c$	$12.35 + 1.366*P_b$	$14.19 + 1.366*P_b$
Total with a $52/tC CT[h]	$10.87 + 1.115*P_{ng}$	$10.54 + 1.115*P_{ng}$	$10.71 + 1.059*P_{ng}$	$15.30 + 1.292*P_c$	$15.00 + 1.292*P_c$	$12.63+ 1.366*P_b$	$13.23 + 1.366*P_b$
Lifecycle CO_2 Emissions (kg C/GJ of H_2)	+ 21.8	+21.4	+ 11.1	+ 41.2	+ 11.4	+ 5.4	- 18.4

Notes for Table 7

[a] Assuming average values for sequestration costs in Tables 4, 5, and 6. Here P_{ng} is the wellhead NG price (in $/GJ); P_c and P_b are, respectively, the prices of coal and biomass delivered to the conversion facility.

[b] For the pipeline transmission and distribution (T&D) system associated with producing H_2 from NG near the NG field, it is assumed that the output for a cluster of 5 plants [a production rate of 95.45 PJ/year (850.3 million scf/day)] is transported 1000 km in a 81.3-cm (32-inch) pipeline, for which the inlet and outlet pressures are 75 bar (1087.5 psia) and 48 bar (697 psia), respectively. At the end of this pipeline, the output is divided into 5 equal parts, each of which are transported another 100 km in 30.5-cm (12-inch) pipelines, for which the outlet pressure is 20.3 bar (294 psia). At the ends of these pipelines the H_2 is transported 10 km further to refueling stations in 4.2-cm (1.7-inch), 1million scf/day (0.113 PJ/year) lines for which the outlet pressure is 14 bar (200 psia).

Notes for Table 7, continued

[c] In this instance NG is piped from the NG field via 1000 km and 100 km pipelines (similar to those described in note b) to a H_2 conversion plant at the city gate. The cost of compressing the NG and transmitting it to the city gate adds \$0.64/GJ to the cost of H_2 production. Since the plant is so close to the market, the H_2 recovered from the PSA unit need not be compressed to high pressure at the production plant. Here it is assumed that H_2 is instead sold at the 20.3 bar pressure at which it is recovered from the PSA unit, saving \$0.35/GJ in compression costs. This compression savings is much larger than the cost of compressing NG at the gas field to 75 bar. The lifecycle CO_2 emissions are reduced slightly as a result of this compressor work savings.

[d] It is assumed that the output for a single plant producing H_2 from coal [a production rate of 37.76 PJ/year (336.5 million scf/day)] is transported 100 km in a 32.3-cm (12.7-inch) pipeline, for which the inlet and outlet pressures are 75 bar psia and 20.3 bar, respectively. At the end of this pipeline, the H_2 is transported 10 km further to refueling stations in 4.2-cm (1.7-inch), 1 million scf/day lines for which the outlet pressure is 14 bar.

[e] It is assumed that the output for a single plant producing H_2 from biomass [a production rate of 7.73 PJ/year (68.9 million scf/day)] is transported 100 km in a 17.7-cm (7-inch) pipeline, for which the inlet and outlet pressures are 75 bar and 20.3 bar, respectively. At the end of this pipeline the H_2 is transported 10 km further to refueling stations in 4.2-cm (1.7-inch), 1 million scf/day lines for which the outlet pressure is 14 bar.

[f] Hydrogen T&D costs presented here are illustrative rather than definitive. (The pipeline/compressor systems are not optimized.) Flow rate and cost calculations are based largely on Christodoulou (1984). However, it is assumed that pipeline unit costs are never lower than about \$180/m, the actual installed cost for a 2700 m pipeline rated for 1000 psia with D = 3 inches (Ogden et al., 1995); thus, for small diameter pipelines, it is assumed that the cost per meter of pipe is independent of the pipe diameter. It is assumed that pipelines last 50 years, so that the annual capital charge rate (including an insurance rate of 0.5%/year) is 0.1059.

[g] See Table 8.

[h] This is the carbon tax (CT) required to make the cost of H_2 produced from NG with sequestration in a depleted NG field equal to the cost of H_2 produced from NG at the city gate without sequestration. At this tax level the cost of H_2 produced from coal with sequestration is also less than the cost of H_2 produced from coal without sequestration.

Table 8. Estimated Cost for Hydrogen Refueling[a]	
Cost Component	\$/GJ of delivered H_2
Capital for H_2 storage at the refueling station[b]	2.00
Capital for compressor[c]	0.61
O&M for compressor[d]	0.02
Electricity for compressor[e]	1.08
Hydrogen dispenser and controls[f]	0.36
Labor[g]	1.00
Total	5.07

Notes for Table 8

[a] For a large refueling station providing 10^6 scf/day (0.132 million GJ/year) of gaseous hydrogen, based on a design by Ogden et al. (1995). It is assumed that fuel cell cars have a 250-mile (400-km) range and that the average fuel economy of these cars is 71.6 mpg (30.4 km/liter) of gasoline equivalent, so that refueling requirements are 0.46 GJ/car, and 787 cars are refueled per day. Further it is assumed that H_2 is stored onboard cars @ 552 bar (8000 psia), and that the compressor discharge pressure at the refueling station is 58 bar (8400 psia).

[b] Storage cylinders for the refueling station having a maximum operating pressure of 8400 psia and have a capacity of 6005 scf each and an installed cost per vessel of \$10,500. The refueling station needs 150 cylinders, so that the total capital cost is \$1.575 million. The cylinders are expected to last 10 years. The annual capital charge rate (including an insurance rate of 0.5%/year) is thus 0.1677

[c] The compressor capacity required for the refueling station (for inlet and outlet hydrogen pressures of 200 psia and 8400 psia, respectively) is 270 kW_e, its installed cost is estimated to be \$1919/kW_e, and its lifetime is expected to be 100,000 hours (11.4 years), so that the annual capital charge rate (including an insurance rate of 0.5% per year) is 0.1559.

[d] Ogden et al. (1995) estimate the annual cost for the compressor to be \$3000 .

[e] Electricity requirements are 6.49 kWh/1000 scf (17.93 kWh/GJ) of H_2. It is assumed that the electricity price is \$0.06/kWh.

[f] The capital cost for the hydrogen dispenser, priority panel and sequencer are estimated to be \$285,500. This equipment is expected to last 10 years. The annual capital charge rate (including an insurance rate of 0.5%/year) is thus 0.1677

[g] The annual labor cost is \$131,400 per year, assuming a labor plus benefits rate of \$15/hour.

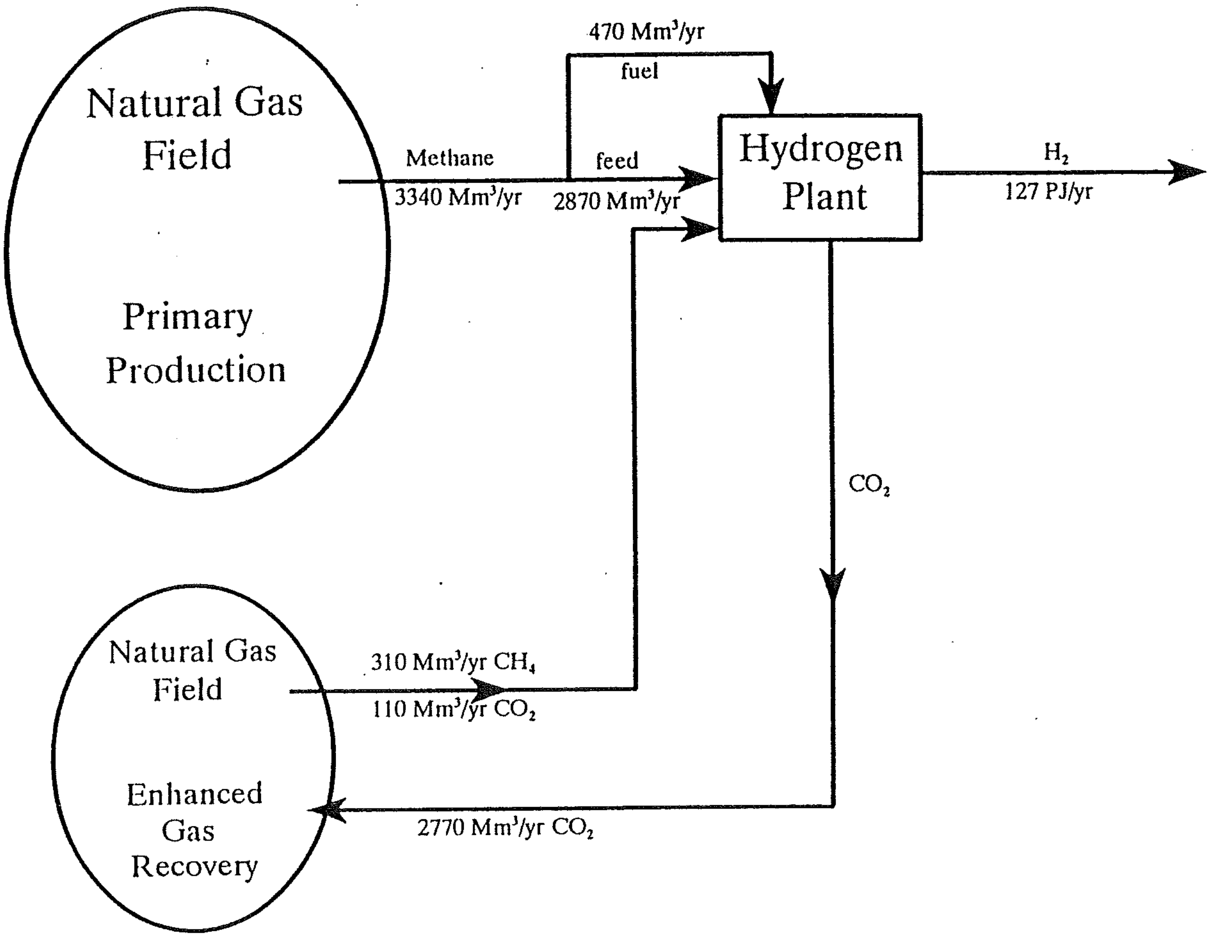

Figure 1. Wellhead Production of Hydrogen from Natural Gas with Injection of the Separated CO_2 into a Depleted Natural Gas Field and Enhanced Natural Gas Recovery as a Result of Reservoir Repressurization.

This illustrates, for a large prototype depleted natural gas reservoir in The Netherlands (the reservoir is characterized by small permeability differences between adjacent layers) the mass balances for a system involving hydrogen production from natural gas, injection of the separated CO_2 into the reservoir, and the enhanced natural gas production that is made possible by reservoir repressurization. The reservoir is capable of sustaining a CO_2 injection rate of 15,000 tonnes per day. Injection begins after 20 years of primary natural gas production, by which time the reservoir pressure has fallen to 30 bar, from the original pressure of 350 bar. During the next 15 years there is enhanced natural gas recovery that makes it possible in this instance to provide about 8.5% of the natural gas requirements for the hydrogen production facility "free," as a result of reservoir repressurization via CO_2 injection. (This corresponds to the case with "high credit for enhanced natural gas recovery" in Table 4.) The reservoir pressure reaches about 130 bar after 15 years of CO_2 injection. The recovered gas is about 3/4 natural gas, the rest being CO_2. It is assumed that the small level of overall contamination (< 5% of the total gaseous input to the hydrogen production plant is CO_2) is readily managed in the hydrogen production process. The hydrogen production plant is sized to match the depleted reservoir capacity for accepting CO_2. For details, see Blok et al. (1995).

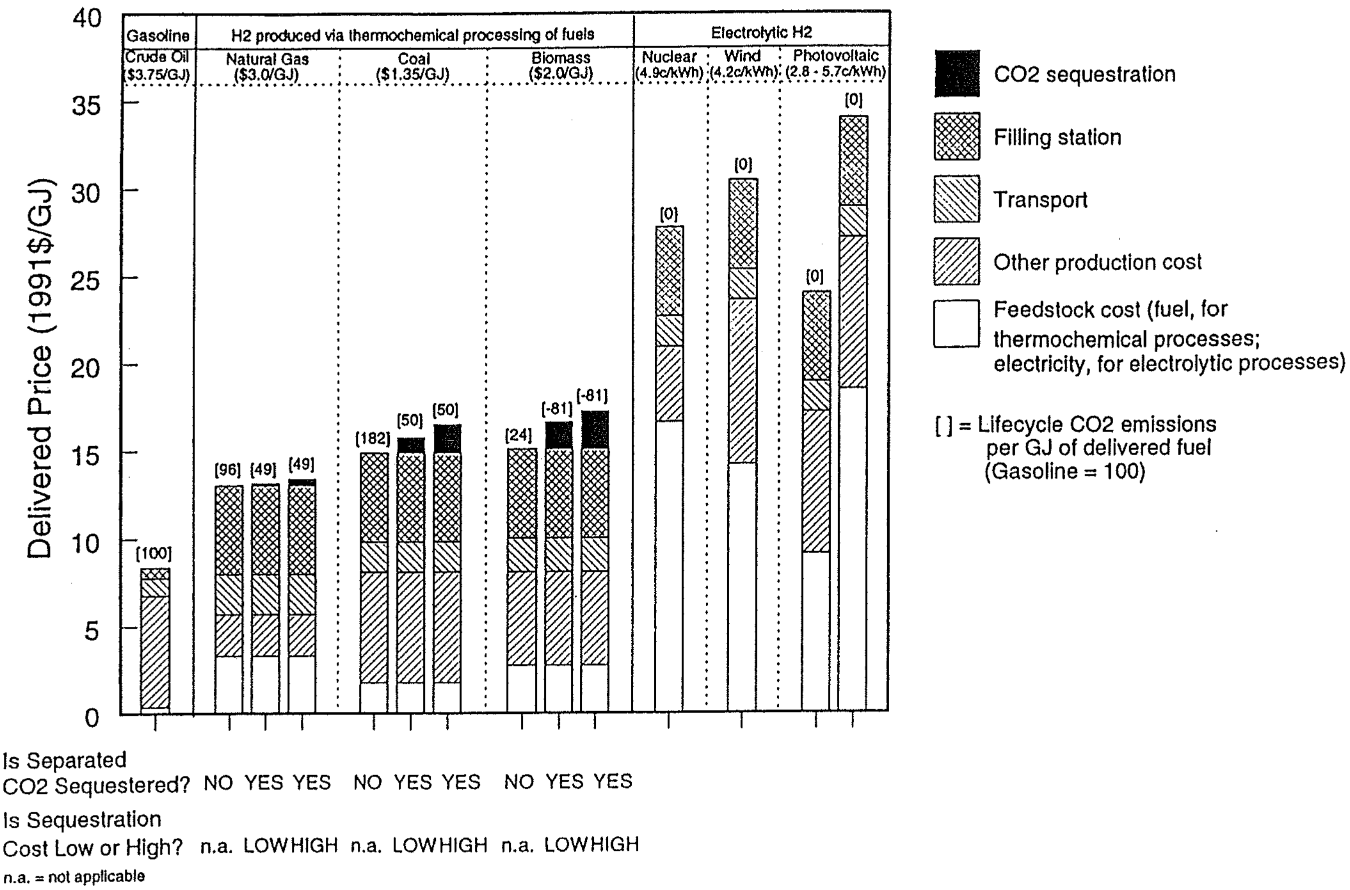

Figure 2. The Estimated Cost to Automotive Consumers of Pressurized Hydrogen Derived from Alternative Sources, per Unit of Delivered Energy

The costs for hydrogen derived thermochemically from natural gas, coal and biomass are based on the transmission, distribution, and refueling station costs shown in Table 7 and on the production costs presented in Tables 4, 5, and 6--for natural gas, coal, and biomass prices of \$3.0/GJ, \$1.35/GJ, and \$2.0/GJ, respectively. The cost for reformulated gasoline derived from \$23/barrel crude oil is shown for comparison. Retail fuel taxes on not included.

The cost of hydrogen derived from natural gas without sequestration is for a plant sited at a depleted natural gas field. The sequestration costs shown for coal and biomass are for sequestration in saline aquifers located 250 km from the hydrogen production facilities. The costs for hydrogen derived electrolytically from nuclear and wind (photovoltaic) sources are for the indicated ac (dc) electricity prices, assuming an 85% efficiency for electrolysis and a 96% efficiency for rectification. The cost of transporting electrolytic hydrogen from production facilities to refueling stations is assumed to be the same as for hydrogen derived from coal. In all cases production costs include the costs for pressurization to 75 bar at the production plant. For the intermittent renewable electric sources, costs for hydrogen storage are also included in production costs.

The numbers at the tops of the bars are the lifecycle CO_2 emissions in kg C per GJ of delivered fuel, relative to lifecycle emissions for gasoline.

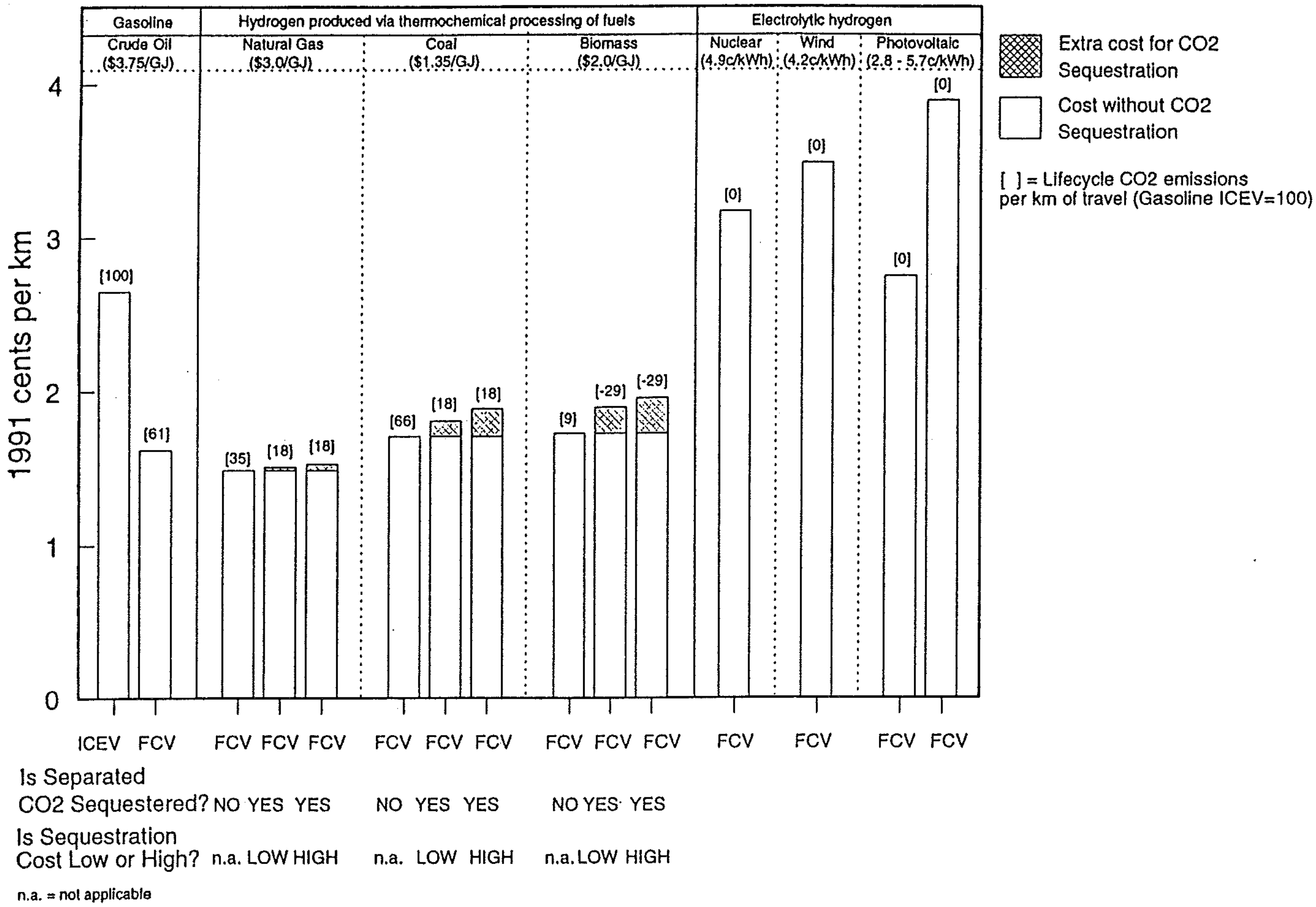

Figure 3. The Estimated Cost to Automotive Consumers of Pressurized Hydrogen Derived from Alternative Sources, per km of Driving

The consumer prices and lifecycle CO_2 emissions for hydrogen shown in Figure 2 are converted here to fuel costs and lifecycle CO_2 emissions per km of driving a fuel cell vehicle (FCV), along with a comparison of gasoline costs and lifecycle CO_2 emissions per km of driving, for both internal combustion engine vehicle (ICEV) and FCV applications. Retail fuel taxes are not included.

The reference gasoline ICEV is a year-2000 version of the Ford Taurus automobile with a fuel economy of 11.0 km/liter. The hydrogen FCV has performance characteristics that are comparable to those for this ICEV and a gasoline-equivalent fuel economy of 30.4 km/l. Fuel costs are also shown for a FCV operating on gasoline. In this case the gasoline is converted via partial oxidation onboard the vehicle to a gaseous mixture of H_2 and CO_2, which is a suitable fuel gas for operating the fuel cell; the estimated fuel economy for the gasoline FCV is 18.0 km/l.

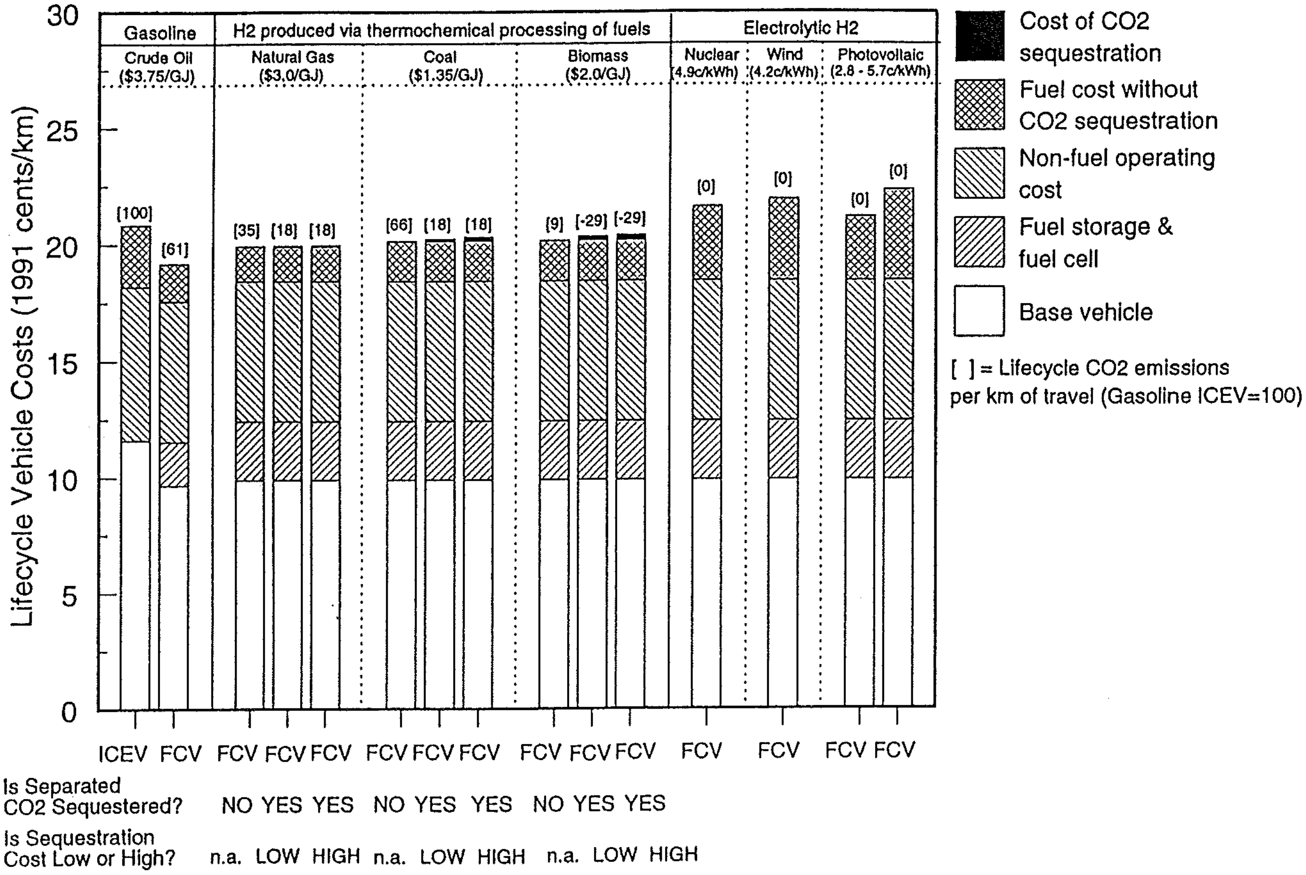

Figure 4. Estimated Lifecycle Cost to Consumers for Owning and Operating a Hydrogen Fuel Cell Vehicle for Hydrogen Derived from Alternative Sources, per km of Driving

Vehicle performance and cost characteristics are based on Ogden et al. (1994). Fuel costs are from Figure 3. Operating lifetimes of 241,000 km and 193,000 km are assumed for fuel cell vehicles (FCVs) and internal combustion engine vehicles (ICEVs), respectively. It is assumed that hydrogen is stored onboard vehicles in carbon-fiber-wrapped aluminum tanks @ high pressure (550 bar). Because of the bulkiness of gaseous hydrogen storage, the hydrogen FCV is designed for a range between refuelings of 400 km, compared to 640 km for a gasoline ICEV. The weight of the hydrogen FCV is estimated to be 1.3 tonnes, compared to 1.4 tonnes for the ICEV. Initial costs are estimated to be $17,800 for an ICEV and $25,100 for a hydrogen FCV (in mass production). The initial cost for a gasoline FCV is assumed to be $21,700, the same as the estimated cost for a methanol FCV (Ogden et al. 1994). Retail fuel taxes are included under "other non-fuel operating costs" at the average US rate for gasoline used in ICEVs; to ensure that road tax revenues are the same for all options, it is assumed that retail taxes are 0.75 cents per km for all options (equivalent to 8.2 cents per liter or 31 cents per gallon for gasoline used in ICEVs).