

**HYDROGEN AND METHANOL:  
PRODUCTION FROM BIOMASS AND  
USE IN FUEL CELL AND  
INTERNAL COMBUSTION ENGINE VEHICLES  
A Preliminary Assessment**

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## ABSTRACT

A systematic analysis is presented of the production of hydrogen and methanol from biomass and the use of these fuels in fuel cell and internal combustion engine vehicles. Comparisons are made among these options and with gasoline-fueled internal combustion engine vehicles, with regard to performance, cost, and environmental and energy security impacts. It is found that the fuel cell vehicle options offer major energy security and environmental advantages and may well be able to compete with the gasoline-based internal combustion engine on a lifecycle cost basis, despite the prospect of higher biofuels costs and higher first costs for fuel cell vehicles. While the methanol fuel cell option is likely to be less costly than the hydrogen fuel cell option and to be easier to implement, the hydrogen fuel cell option offers greater long-term energy security and environmental benefits.

## INTRODUCTION

The transportation sector poses formidable energy security and environmental challenges. The security challenge arises from the near total dependence of the road transport system on petroleum, for which the remaining low-cost supplies are concentrated in the politically volatile Middle East. The use of liquid hydrocarbon fuels for transport is also a major source of urban air pollution in most parts of the world, accounting for a large fraction of total emissions of oxides of nitrogen ( $\text{NO}_x$ ), nonmethane organic compounds (NMOC), and carbon monoxide (EPA, 1991). And motor vehicles account for 25-30% of  $\text{CO}_2$  emissions from the burning of fossil fuels in industrialized countries (DeLuchi, 1991a) and are making a rapidly growing contribution to  $\text{CO}_2$  emissions worldwide (MacKenzie and Walsh, 1990). While there is as yet no consensus as to the preferred approach to meeting these challenges, several points are clear.

First, these energy security and environmental problems will be aggravated unless fundamental changes are made in the road transport system. The US Department of Energy projects that between 1989 and 2010, US domestic crude oil production will decline from 17.0 EJ/year to 10.7 EJ/year, oil imports will increase from 16.2 EJ/year to 28.9 EJ/year, and road transportation fuel demand will increase from 17.5 EJ/year to 20.6 EJ/year (EIA, 1991a). Likewise, the expected continuing growth in motor vehicle travel will eventually offset the reduction in emissions expected as a result of the new tailpipe emissions standards in the 1991 Clean Air Act. Anticipating this, California has adopted tougher regulations, including a requirement that 10% of

the vehicles sold in the state in 2003 emit zero pollutants (CARB, 1990)--a requirement that cannot be met by hydrocarbon-fueled vehicles. Other states are considering similarly strict standards (Wald, 1991). Moreover, concerns about global warming may also force dramatic changes in road transport technology. These concerns already have led the Commission of European Communities to set a target of stabilizing CO<sub>2</sub> emissions by 2000 at the 1990 level, and some individual countries have set for themselves even more ambitious targets (e.g. reductions in the range 20-30% have been targeted by Australia, Germany, and New Zealand for the period 2000- 2005). A reduction of 60% or more in global CO<sub>2</sub> emissions is needed to stabilize the atmosphere (IPCC, 1990). In the transport sector such large reductions cannot be achieved without substantially increasing fuel economy and/or switching to alternative energy sources.

Second, it is desirable to avoid committing to those strategies that would alleviate some problems but in the long run aggravate others. An example might be a shift from gasoline to methanol in cars with internal combustion engines. Such a shift could provide some air quality benefits, as well as reduce oil dependency. Initially methanol would be produced mainly from natural gas, but ultimately, as world gas supplies tighten, the resource base might be shifted to much more abundant coal, which would exacerbate the problem of global warming, since greenhouse emissions per vehicle-kilometer for coal-derived methanol would be much greater than those for gasoline (DeLuchi, 1991a).

Third, it is desirable to have secure, clean, and sustainable energy options that also satisfy consumer preferences. Both the battery-powered electric vehicle (BPEV) and the fuel cell vehicle (FCV) supplied with energy from non-fossil fuel sources are zero-emission options that do not depend on imported oil. However, without radical changes in consumer habits or in the infrastructure for providing electricity, the BPEV probably could not capture more than 15% of the automotive market because of the long recharging time (several hours) for the BPEV (Nesbitt et al., 1991).

This paper presents preliminary results of an analysis of the performance and costs for fuel cell cars operated on methanol and hydrogen derived from biomass. Fuel cell cars operated on biomass-derived fuels could improve urban air quality, reduce emissions of greenhouse gases, and reduce dependence on foreign oil, while satisfying most consumer expectations about vehicle performance and cost. The hydrogen fuel cell option is particularly attractive because biomass-derived hydrogen can be complemented by hydrogen derived from a variety of other clean and secure energy sources.

## METHANOL AND HYDROGEN PRODUCTION

Both methanol ( $\text{CH}_3\text{OH}$ ) and hydrogen ( $\text{H}_2$ ) can be produced from biomass by thermochemical routes that begin with the same gasification process. Gasification leads to a gaseous fuel mixture consisting mainly of  $\text{CO}$ ,  $\text{H}_2$ ,  $\text{CO}_2$ , water vapor and  $\text{CH}_4$ , and small amounts of higher hydrocarbons. After gasification, methane (and other hydrocarbons) would be reformed at high temperature with steam in both instances,



to produce synthesis gas, for which nearly all the fuel energy is carried by  $\text{CO}$  and  $\text{H}_2$ .

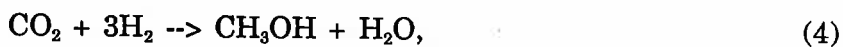
In the case of methanol, the further processing involves first shifting some of the  $\text{CO}$  in the synthesis gas to hydrogen via the water-gas shift reaction,



until the concentration of  $\text{H}_2$  in the gas is sufficiently high that the volumetric ratio  $(\text{H}_2 - \text{CO}_2)/(\text{CO} + \text{CO}_2)$  for the gas entering the methanol synthesis reactor will be greater than two, as needed for methanol synthesis. Shifting is followed by removal of the  $\text{H}_2\text{O}$  and most of the  $\text{CO}_2$  and then methanol synthesis. The dominant synthesis reaction is



A second reaction



plays a minor role. Finally, the produced methanol is purified through distillation.

Hydrogen production involves shift conversion of much more of the  $\text{CO}$  to  $\text{H}_2$ , followed by hydrogen separation from the shifted synthesis gas using a pressure swing adsorber or an alternative technology.

For either energy carrier, all system components except the gasifier are commercially available and widely utilized in the chemical process industries. There are also coal gasifiers on the market that can be adapted to biomass.

The technology for producing methanol from coal via coal gasification is well-understood (Probstein and Hicks, 1982; OPPA, 1989). Though it has been given less attention, hydrogen produced via coal gasification is also well understood (Kim et al., 1979; Probstein and Hicks, 1982; Minet and Desai, 1983). Concerns about global warming have led to a proposed variant of the hydrogen-from-coal concept that involves sequestering the recovered CO<sub>2</sub> by injection into depleted natural gas wells (Blok et al., 1991).

Overall performance in the production of hydrogen or methanol from biomass could be considerably improved by the use of new gasifiers designed to take advantage of the unique properties of biomass as alternatives to gasifiers designed for coal but adapted to biomass (Stevens, 1991; Wyman et al., 1992). Several such systems have been operated at pilot scale but require commercial-scale demonstration before they can be considered commercially ready.

It is desirable to use gasifiers designed specifically for biomass because biomass differs from coal in important ways (Antal, 1980; 1983). Typical biomass feedstocks contain 75-85% volatile matter, compared to half or less this level with coal (Larson et al., 1989). Biomass also contains considerably more oxygen and about 50% more hydrogen per unit of energy than coal.<sup>1,2</sup> The high volatile content of biomass means pyrolysis (devolatilization), the first (low-temperature) stage in gasification, plays a larger role with biomass than with coal. Also, biomass pyrolyzes at lower temperatures than coal (Fig. 1). Furthermore, the char that remains after devolatilization is 10-30 times more reactive than most coal chars (Graboski, 1982). Thus, biomass gasifiers can operate at lower temperatures than coal gasifiers to achieve the same char conversion level (Fig. 2). In addition, most biomass feedstocks contain little or no sulfur and much less ash (typically 1% by weight compared to 10% for coal) (Jenkins, 1989).

Many previous studies have evaluated the production of methanol from biomass [e.g. see Wyman et al (1992); Stevens (1991); OPPA (1990); Kosstrin and Himmelblau (1985)]. The production of hydrogen from biomass has been investigated much less, though a pioneering study carried out at the Hawaii Natural Energy Institute and the Florida Solar Energy Center concluded that biomass gasification offers the most economical route for producing hydrogen from renewable energy sources (Takahashi,

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<sup>1</sup> Typical biomass and coal feedstocks, with heating values of approximately 20 and 30 GJ per dry tonne, respectively, can be represented approximately by the chemical formulas CH<sub>1.5</sub>O<sub>0.66</sub> and CH<sub>0.8</sub>.

<sup>2</sup> Higher heating values are used throughout this paper.

1989). More recently, a promising advanced approach to hydrogen production from biomass, involving gasification in supercritical water, has been described (Manarungson, 1991). The present analysis is aimed at making a systematic comparison of the production of hydrogen and methanol from biomass.

## Gasifier Options

Biomass gasifiers have been designed to operate on one of two fundamental principles--direct heating (partial oxidation) or indirect heating.

### *Directly-heated gasifiers*

In directly-heated gasifiers heat is provided by partially oxidizing some of the biomass feedstock in air or oxygen. For the production of methanol or hydrogen, oxygen rather than air is used, to minimize the gas volumes that must be treated downstream.

There have been significant efforts worldwide to adapt to biomass the fixed-bed and fluidized-bed gasifier designs originally developed for coal (Synthetic Fuels Associates, 1983). Various units are operating commercially on biomass feedstocks (Larson et al., 1989).

Directly-heated gasifiers are characterized by relatively high peak operating temperatures (900°C to 1200°). Such temperatures are required for efficient gasification of coal. One advantage of these units for hydrogen or methanol production is the relatively low hydrocarbon fraction in the product gas compared to gasifiers that operate at the same pressure but lower temperatures.<sup>3</sup> (Low hydrocarbon content minimizes the need for a reforming step after gasification.) A disadvantage is that the need for oxygen increases capital and operating costs. This requirement is particularly troublesome at the smaller scales of most biomass conversion facilities, because the unit capital cost of oxygen plants is characterized by strong scale economies.

For methanol or hydrogen production, it is advantageous to operate the gasifier at elevated pressure. While there are no pressurized gasifiers operating commercially

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<sup>3</sup> The formation of methane and other higher hydrocarbons is favored at lower temperatures and higher pressures.

on biomass, there are several ongoing developmental efforts (Larson et al., 1989). One involves the bubbling fluidized bed gasifier being developed by the Institute of Gas Technology (IGT). A pilot-scale IGT gasifier has been successfully operated on a variety of biomass feedstocks at pressures up to 23 bar (Evans et al., 1988). Construction of a scaled-up demonstration unit is scheduled to begin in Hawaii in late 1991 (Trenka et al., 1991). The gasifier will be operated primarily on sugarcane bagasse (70 tonnes/day capacity). Another is the fixed-bed, down-draft gasifier (11 bar) for which the development work was initiated at the Solar Energy Research Institute (SERI) and the intended initial application was to be small-scale methanol production (Reed et al., 1987). Subsequently, rights to the technology were acquired by a private company that continued development work on a commercial-scale unit (40 dry tonnes/day capacity) operated at slightly positive pressure, to produce fuel gas for stationary, internal combustion engines (Graboski and Brogan, 1988).

#### *Indirectly-heated gasifiers*

Indirectly-heated gasifiers, unlike directly-heated units, are designed to take advantage of the higher reactivity of biomass relative to coal. A number of different designs have been developed to the pilot stage. The most advanced of these must be demonstrated at larger scale before the technology can be considered commercially ready. In each design, heat is supplied to the reactor through heat-exchange tubes or by an inert heat-carrying material like sand. Steam is injected with the feedstock in most of the designs to help promote the gasification reactions. Because of the indirect heating, the reactor temperatures are lower than in directly-heated units, but they are sufficiently high (600°C to 900°C) to effectively gasify the highly reactive biomass. The indirect heating leads to the production of a gas undiluted by nitrogen, without the use of costly oxygen. A disadvantage of indirectly-heated reactors is the relatively large fraction of methane in the produced gas.

One indirectly heated gasifier is under development at the Battelle Columbus Laboratory (BCL). The BCL gasifier is an atmospheric-pressure twin fluid-bed unit in which devolatilization and pyrolytic gasification occur in one bed. The char that remains is transferred to a second bed, where it is burned in air. Heat from the combustor is supplied to the pyrolysis reactor in the form of heated sand exchanged between the two units (Wyman et al., 1992; Feldman et al., 1988). The flue gases from the combustor are used to dry the biomass feed for the gasifier. Some steam is injected into the gasification bed, where reactions occur at about 980°C. The product gas contains some tar, which can be removed in a quench stage, separated from the



quench water, and burned in the combustor. To date, a BCL unit has been operated at a scale of 850 kg/hour.

Another unit being developed by Manufacturing and Technology Conversion International (MTCI) is an atmospheric-pressure fluidized-bed gasifier with in-bed heat exchanger tubes (MTCI, 1990). Some of the produced gas is burned by pulse combustion (Parkinson, 1990) inside the tubes, providing the heat needed for gasification. Pulse combustion leads to heat transfer rates about five times those for conventional in-tube heating. At a relatively low reactor operating temperature (700°C) the high heat transfer rate, together with some injection of steam, yields efficient gasification. The MTCI technology is being developed for initial use with black liquor, the lignin-rich spent liquor generated in the production of woodpulp using the Kraft process. An MTCI black liquor gasifier with a capacity of 72 dry tonnes per day is currently being installed in a pulp mill in New Bern, North Carolina (Parkinson, 1990). Less effort has been devoted to developing the gasifier for solid biomass fuels. A similar gasifier design, but one that does not use pulse combustion, is under development at the University of Missouri (Flanigan et al., 1988).

The Wright-Malta (WM) gasifier is a pressurized rotor-kiln designed to directly utilize wet (typically 50% moisture content) biomass (Coffman, 1981; Coffman and Hooverman, 1978). The gasifier provides a methane-rich, tar-free gas, as a result of the combined effects of pressurization (15 bar), low reactor temperature (600°C), long solids residence time (1 hour), and the catalytic effects of ash recirculation. No steam addition is required, since the internal mixing and long residence time allow the natural moisture of the wet biomass to be fully utilized in the reactor. A pilot scale demonstration is in the planning stages (Coffman, 1991).

### **Preliminary Process Energy and Mass Balances**

The WM gasifier was chosen as the basis for a systematic comparison of the performance and costs of producing methanol and hydrogen from biomass. Several considerations motivated this choice. First, this gasifier is indirectly heated, which

appears to be advantageous for biomass feedstocks.<sup>4</sup> Second, this gasifier is pressurized, which is advantageous for producing either hydrogen or methanol. Third, with this gasifier feedstock drying costs are avoided, since wet fuels can be used directly.

Despite such considerations, the purpose of the present analysis was not to identify the optimal gasifier for fluid fuels production but rather to choose a specific gasifier that has been well enough characterized to permit a self-consistent comparison of methanol and hydrogen from biomass with regard to overall efficiency and cost. In light of the fact that the processes for producing methanol and hydrogen differ mainly with regard to features downstream of the gasifier, it is likely that analyses based on other gasifier designs would provide the same relative ordering but generally different absolute values for efficiency and cost.

Process models have been developed to provide a basis for a consistent comparison of energy and mass flows in methanol and hydrogen production systems (Larson et al., 1991). The models are based on the use of off-the-shelf technology in all cases, except for the biomass gasifier. Published performance characteristics of the WM gasifier (Coffman, 1981) were used in these models. Chemical reactors downstream of the gasifier (reformer, shifter, methanol synthesis reactor) have been modeled assuming chemical equilibrium and typical approach temperatures. Physical separation steps (CO<sub>2</sub> removal and H<sub>2</sub> purification) have been modeled based on performance estimates obtained from vendors.

### *Methanol*

In the production of methanol (Fig. 3), wet biomass (45% moisture content) is fed to the gasifier, and ash and some unconverted char are rejected. The sensible energy in the reformed gas provides some of the heat requirements for the gasifier through a heat exchanger; the balance of the gasifier energy needs are provided by the exothermicity of the low-temperature pyrolysis reactions in the gasifier (Hooverman, 1979). The product gas, consisting of 12% H<sub>2</sub>, 4% CO, 22% CO<sub>2</sub>, 20% CH<sub>4</sub>, and 42% H<sub>2</sub>O by volume, exits the gasifier at 600°C.

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<sup>4</sup> It is premature to conclude, however, that indirectly heated gasifiers will always be preferred. Pressure-swing adsorption and membrane separation technologies are providing increasing competition to cryogenic distillation for oxygen production (Shelley, 1991). Such alternative technologies might eventually enable oxygen-blown gasifiers to compete with indirectly heated gasifiers at the modest scales needed for biomass.

Whether or not the product gas must be cleaned before further processing is uncertain. Tars and particulates are expected to be negligible in the product gas because of the long residence time (Coffman, 1981), and sulfur levels are expected to be negligible because biomass generally contains little sulfur. However, particulate and sulfur levels must be kept very low to protect the downstream processing equipment--e.g. the H<sub>2</sub>S level must be less than 0.25 ppm to protect the nickel catalyst in the reformer. Accordingly, performance and cost calculations have been carried out both with and without a quench to remove tars and a guard bed to remove sulfur and chlorine. The base-case analysis includes gas cleanup.

The methane fraction of the gas is sharply reduced in the reformer. Since the reformer feed gas is moisture-rich, little or no external steam input is needed, in contrast to the situation when natural gas is reformed. At the reformer exit the gas is made up of 40% H<sub>2</sub>, 20% CO, 12% CO<sub>2</sub>, 3% CH<sub>4</sub>, and 25% H<sub>2</sub>O.

Because the molar ratio  $(H_2 - CO_2)/(CO + CO_2)$  of the gas supplied to the methanol synthesis unit must be greater than two, some of the CO in the gas exiting the reformer is shifted to hydrogen in a single-stage shift reactor. Subsequently, the shifted gas is cooled before the H<sub>2</sub>O and CO<sub>2</sub> are removed in a Selexol physical absorption unit. (A small amount of carbon dioxide (2-3% by volume) is left in the gas to ensure proper operation of the catalyst in the synthesis reactor.)

Since the production of methanol in the synthesis unit is favored by high pressures and low temperatures, the gas is compressed following the removal of the H<sub>2</sub>O and CO<sub>2</sub>. The use of a methanol synthesis unit of the type produced by ICI (96 bar, 270°C exit conditions) is assumed here. Only a fraction of the carbon is converted to methanol on each pass through the reactor, so a recycle loop is included as part of the synthesis step to increase overall conversion. The recycle ratio is selected such that heat from the combustion of the gas purged from the recycle loop provides sufficient heat to run the reformer. The final step in the synthesis unit, methanol purification by distillation, has only a small impact on the overall heat balance and cost of the process.

The overall efficiency of producing methanol from biomass<sup>5</sup> with this system is about 54% with quenching or 57% without. For comparison, the efficiency of producing methanol from coal using the Texaco gasifier has been estimated to be 56% (OPPA,

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<sup>5</sup> The efficiency is defined as the ratio of the higher heating value of the produced methanol to the higher heating value of the biomass feedstock.

1989), while the efficiency of producing methanol from biomass using the BCL gasifier has been estimated to be 57% (Wyman et al., 1992).

### *Hydrogen*

The gasification, quenching, and reforming steps for hydrogen production are identical to those for methanol production (Fig. 4). After the reformed gas is cooled by transferring heat to the gasifier, it passes through two stages of shift reactors (high and low temperature units), in which the CO is largely converted to H<sub>2</sub> via the water-gas shift reaction (Eqn. 2). The resulting hydrogen-rich gas is then further cooled before being purified in a pressure swing adsorber (PSA), a gas separation technology utilizing molecular sieves (Basta, 1988). The PSA considered here<sup>6</sup> consists of two beds, the first of which removes CO<sub>2</sub> and the second of which produces separate streams of 99.99% pure H<sub>2</sub> and a fuel gas consisting of the remaining H<sub>2</sub> plus the residual CH<sub>4</sub> and CO. Overall, the PSA unit recovers 86% of the volume of H<sub>2</sub> entering the unit (Soloman, 1991). The fuel gas is burned to provide heat for the reformer and for preheating several process streams.

The overall efficiency of producing hydrogen from biomass is estimated to be 63% with quenching and 67% without. This is considerably higher than the efficiency of producing methanol from biomass, but lower than the efficiency of producing pure hydrogen from coal with CO<sub>2</sub> sequestering in depleted gas wells. The latter has been estimated to be 80% for a Shell oxygen-blown, entrained-flow gasifier (Blok et al., 1991).<sup>7</sup>

### **Preliminary Cost Estimates**

The economic analysis for methanol and hydrogen production (Table 1) is based on production facilities with a processing capacity of 3000 green tonnes (1650 dry tonnes) per day. Process component costs were obtained from a variety of sources (notes to Table 1). The capital costs here are estimated to be within  $\pm 25\%$  of what actual costs would be. The financial parameters used in this analysis are taken to be

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<sup>6</sup> The GEMINI-9 PSA System offered by Air Products, Inc., Allentown, PA.

<sup>7</sup> In producing hydrogen from coal (Blok et al., 1991), both pure hydrogen and fuel gas in excess of the internal process needs is produced. The efficiency of producing hydrogen from coal is defined as:  $\text{eff.} = \text{HHV of hydrogen} / [\text{HHV of coal input} - (\text{HHV of fuel gas} / \text{eff.})]$ .

average values for large US corporations in the period 1984-88 (note j, Table 1). The analysis is carried out for biomass feedstocks costing \$2.50/GJ--a cost that can be expected for delivered wet chips derived from biomass produced using Short Rotation Intensive Culture techniques on good agricultural land (Hall et al., 1991).

### *Methanol*

The total cost of producing methanol with the WM gasifier is estimated to be \$14.1/GJ (Table 1). For comparison, Table 2 shows the costs for methanol from biomass based on the oxygen-blown IGT gasifier and the indirectly-heated BCL gasifier. These cost estimates are based on calculations from other studies modified (see notes to Table 2) to conform to the assumptions underlying the present analysis. It is seen that the cost of methanol from the IGT gasifier would be about 1/6 less than from the WM gasifier, while the cost of methanol based on the BCL gasifier would be about 1/3 less.

This comparison indicates that advantages offered by the WM gasifier of pressurization and being able to use wet fuels directly are not adequate to offset some of its intrinsic shortcomings. A high unit capital cost accounts for much of differences between the cost of the WM and the other biomass gasifiers indicated in Table 2. The unit capital cost of the WM gasifier is about 30% higher than that for the IGT gasifier and nearly 90% greater than that for the BCL gasifier. The long residence times for the WM gasifier imply a low throughput rate and correspondingly a relatively high unit capital cost. Also mechanical considerations limit the capacity of a full-scale WM unit to about 300 green tonnes per day of feedstock (Coffman, 1991), so that the opportunities for capturing scale economies in gasification are limited. In contrast, both the IGT and BCL gasifiers are fluidized bed units with relatively high throughput rates and correspondingly low unit capital costs. Most of the reduction in cost in shifting from the IGT to the BCL gasifier is due to the absence of an oxygen plant for the BCL gasifier and its higher biomass conversion efficiency.

Also shown in Table 2 is the cost of methanol from coal based on the use of the Texaco oxygen-blown, entrained-flow gasifier. One would expect the cost of methanol to be lower for coal than for biomass feedstocks. One reason is that the price of coal is generally lower; in this case coal is assumed to cost just 3/5 as much as biomass, per unit of energy. Another is that coal-to-methanol plants can be built large to capture economies of scale, while biomass-to-methanol plants will tend to be smaller, so as to reduce the costs of transporting biomass from dispersed production sites to the conversion facility; in this case, for example, the capacity of the Texaco facility would

be nearly five times that of the BCL facility. Despite these differences, methanol from biomass produced in the BCL gasifier may be roughly competitive with methanol from coal (Table 2)--essentially because the BCL gasifier is designed to exploit the special characteristics of biomass as a feedstock for gasification (Wyman et al., 1992).

### *Hydrogen*

The total cost of producing hydrogen per unit of energy with the WM gasifier is estimated to be \$10.2/GJ (Table 1), nearly 30% less than the cost of producing methanol with this gasifier. Almost 2/3 of the cost difference is due to the much lower capital cost for the hydrogen production system.

The production cost for hydrogen would probably be lower if the BCL gasifier were used instead. If the cost reduction associated with this shift were in the same ratio as for methanol production (Table 2), the production cost of hydrogen based on the BCL gasifier would be about \$7 per GJ. Whether or not the cost of hydrogen would actually be this low with the BCL gasifier must be determined by a detailed assessment of hydrogen production with that gasifier. The economic analysis of hydrogen production from biomass based on the use of the SERI oxygen-blown gasifier carried out by the Hawaii Natural Energy Institute and the Florida Solar Energy Center (Takahashi, 1989), modified to conform to the financial and biomass feedstock cost assumptions of the present study, leads to a cost of \$8.6/GJ, roughly midway between the cost for the WM gasifier and our "guesstimate" of the cost for the BCL gasifier. This cost position might be expected in light of the facts that: (i) the SERI gasifier, like the IGT gasifier, is oxygen-blown; (ii) the estimated production cost of methanol for the IGT gasifier is approximately midway between the cost estimates for the WM and BCL gasifiers (Table 2).

The cost of producing hydrogen from coal with the Shell gasifier, including the cost of sequestering the recovered CO<sub>2</sub> in depleted natural gas wells (Blok et al., 1991), modified to be consistent with the present study,<sup>8</sup> is about \$7 per GJ, roughly our "guesstimate" for the hydrogen production cost for the BCL gasifier. This is in line

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<sup>8</sup> In addition to using the financial parameters of the present study (note j, Table 1), the coal cost is assumed here to be \$1.48/GJ (note d, Table 2), and the capacity factor is assumed to be 90% (note a, Table 1).

with the comparability of methanol production costs from biomass and coal based on the BCL and Texaco gasifiers (Table 2).<sup>9</sup>

The cost of the hydrogen to the consumer will depend not only on the production cost but also on the way the hydrogen will be used by the consumer. This is illustrated for hydrogen produced using the WM gasifier in Table 3. This table shows that the cost to the consumer would be the lowest for the case where gaseous hydrogen is stored in motor vehicles in metal hydride containers--\$13.2/GJ (\$1.74 per gallon of gasoline-equivalent, exclusive of retail gasoline taxes). In this case hydrogen would be stored at the refueling stations at a pressure of 69 bar (1000 psia) and transferred to the consumers' hydride containers that are pressurized to 52 bar (750 psia; the pressure in the hydride container depends on the type of hydride).

If instead the consumer stores hydrogen gas in canisters pressurized to 620 bar (9000 psia), as is assumed below for fuel cell cars, the refueling station would have to store the hydrogen at 690 bar (10,000 psia). In this case the retail mark-up would be about 75% higher, leading to a consumer price of \$14.7/GJ (\$1.94 per gallon of gasoline-equivalent--Table 3).

If the consumer were to use liquid hydrogen that would be stored in cryogenic dewars, the extra costs of liquefaction and the costs associated with hydrogen transfer losses (estimated to be at least 3% per transfer--Table 3) would drive the consumer price to \$22.9/GJ (\$3.03 per gallon of gasoline-equivalent)--well above that for methanol, some \$17.2/GJ (\$2.26 per gallon of gasoline-equivalent).

In all cases the cost of hydrogen to the consumer would be much greater than the expected price of gasoline in the year 2000 time frame--some \$1.2 per gallon, without the retail gasoline tax (corresponding to a price of \$1.5 per gallon with the tax). This would still be true even if the production cost were as low as \$7 per GJ, as might be the case for the BCL gasifier. (In this case the cost exclusive of retail taxes would be \$1.3 per gallon of gasoline-equivalent for the hydride option, the least costly of the hydrogen options.)

The fuel price per unit of energy content, however, is not a good indicator of economic competitiveness as a transport fuel--one needs to consider the efficiency of fuel

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<sup>9</sup> One might expect the cost of hydrogen from coal to be higher than from biomass because of the added cost of sequestering CO<sub>2</sub> with coal. However, the extra cost for sequestering contributes only about 15% of the total cost of hydrogen from coal, and the Shell gasifier may offer some cost advantages over the Texaco gasifier (Blok et al., 1991).

use, the cost and life of the vehicle, and many other factors as well. As will now be shown, the overall economics depend strongly on the vehicular technology involved and only weakly on the relative fuel prices.

## METHANOL AND HYDROGEN USE IN MOTOR VEHICLES

If methanol or hydrogen from biomass were used as fuel in fuel cell vehicles (FCVs), the extra fuel production costs relative to gasoline would be offset by multiple benefits. FCVs would emit almost no greenhouse gases, regulated pollutants, or toxic air contaminants. They would be much more energy-efficient than internal combustion engine vehicles (ICEVs), and thus much less demanding of primary energy and the land resources needed to grow the biomass. They are expected to be reliable and relatively inexpensive to maintain. And, as will be shown, they may also be no more costly to own and operate than comparable ICEVs.

### **Background on Fuel Cell Vehicles**

Recently, interest in fuel-cell vehicles has grown dramatically. In early 1991 Roger Billings demonstrated a hydrogen-powered FCV that uses metal hydride storage and a compact, lightweight proton-exchange-membrane (PEM) fuel cell (American Academy of Science, 1991). Energy Partners of Florida has announced plans to demonstrate a hydrogen-powered FCV by March 1992. Ballard Technologies of Canada is working on a program to demonstrate a 30-foot transit bus powered by compressed hydrogen and a PEM fuel cell (Prater, 1991). The Canadian Government also is considering a 5-year, \$100 million (Canadian \$) hydrogen research, development, and demonstration program (Prater, 1991).

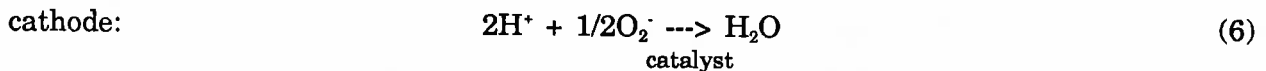
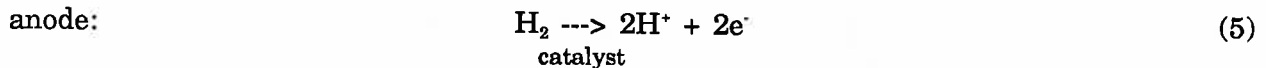
At present the US Department of Energy is supporting two fuel cell projects: the Georgetown Bus Project, which uses a phosphoric acid fuel cell operated on reformed methanol (Kevala, 1990; Romano, 1990), and a project with General Motors, which is to deliver a methanol-fueled, PEM-powered fuel cell automobile within five years (Prater, 1991). DOE support of hydrogen R&D would increase considerably over the present modest level if the Renewable Hydrogen Energy and Research Development Act of 1991 (S. 1269) becomes law. This bill instructs DOE to fund a broad range of hydrogen projects, including hydrogen-powered FCVs (Harkin, 1991).



## Fuel Cell Technology

A fuel cell converts chemical energy contained in hydrogen fuel directly into electrical energy, without first burning the fuel to produce heat. In directly converting chemical energy into electrical energy a fuel cell is like a battery; but unlike a battery, for which the delivered electricity is limited by the battery charge, the hydrogen chemical energy can be supplied continuously. Conversion efficiencies can be much higher than with heat engines because the Carnot "heat trap" is avoided with fuel cells.

Alternative fuel cells operate in slightly different ways; here the operation of the PEM fuel cell [also called the solid polymer electrolyte (SPE) fuel cell], the most promising near-term option for motor vehicles, is described. In a PEM, hydrogen (either stored as such or produced by reforming methanol into hydrogen and CO<sub>2</sub> with steam) is delivered to an electrode (the anode) where it separates, with the help of a platinum catalyst, into hydrogen ions and electrons. The electrons are collected into an external circuit and sent to perform useful work. The hydrogen ions--protons--are transported by an ion-conducting membrane (the proton exchange membrane) to the opposite electrode, where they combine with pressurized oxygen (in air taken from the atmosphere) and the electrons returning from the external circuit to form water. The water is removed from the fuel cell. The reactions at each electrode are simply:



Fuel cells generally are named after their electrolyte (hence the name PEM or SPE). Other types of fuel cells include phosphoric acid, alkaline, and solid oxide.

## The Fuel Cell Vehicle System

In a FCV the electrical output of the fuel cell is used to power the vehicle via an electrical drive train, as in the battery-powered electric vehicle (BPEV). The FCV marries the best attributes of the BPEV--quiet, emission-free, operation, and a low-maintenance, reliable electric drive train--with the best attributes of the ICEV--long range and fast refueling time.

A complete fuel cell system consists of several components: the fuel cell stack itself; a container to store the fuel (hydrogen or methanol); an air compressor, to provide pressurized oxygen to the fuel cell (the efficiency of the fuel cell increases with the partial pressure of oxygen); a cooling system; a water management system, to keep the fuel cell saturated and to remove product water; and an electric motor and controller. If the vehicle stores methanol, rather than hydrogen, it also will have a reformer, to convert the methanol into hydrogen and CO<sub>2</sub>, and some method or device to start the vehicle and follow rapid changes in load, because the reformer does not provide power instantly at start up, and cannot follow rapid changes in power demand.

PEM fuel cells, which will be commercially available in a few years (Prater, 1990), are better suited for near-term vehicular use than are phosphoric acid, alkaline, or solid oxide fuel cells. Phosphoric-acid fuel cells are too large and heavy to be used in many motor vehicle applications; alkaline fuel cells are too intolerant of CO<sub>2</sub> to be used in most terrestrial applications; and solid oxide fuel cells, while promising, are far from commercialization. Most vehicle research, development, and demonstration programs are using (or planning to use) PEM fuel cells. The present analysis is based on the use of the PEM fuel cell, sized to provide the driving range and cruising power for the vehicle.

Several systems analyses have indicated that a small, high-power battery should be used to provide the peak power (Patil and Huff, 1987; Swan, 1989; Kevala, 1990; Romano, 1990). The cost of a battery scales roughly with the amount of energy it can store, so that a battery with a relatively large peak power output but modest storage capacity is relatively cheap, while a fuel cell sized to meet the maximum power requirement of a passenger car would be quite expensive, because its cost scales with the power capacity. Thus, in most designs, the fuel cell provides the cruising range, and the battery provides the peak power. In the systems specified in this paper, the battery is larger in the methanol FCV than in the hydrogen FCV, because it provides all the driving energy immediately after start up until the methanol reformer warms up to its operating temperature (which takes a few minutes). The present analysis is based on the use of a bipolar Li-alloy/FeS<sub>2</sub> battery, a high-temperature battery that is projected to have high specific energy (190 Wh/kg) and very high specific power (500 W/kg) and volumetric energy density (500 Wh/liter) (Kaun et al., 1990).

The hydrogen fuel can be provided by reforming methanol, or by storing hydrogen on board the vehicle. Both cases are considered here. Hydrogen can be stored on board a vehicle as a compressed gas, a metal hydride, a cryogenic liquid, a liquid hydride, or a cryo-adsorbed gas. High-pressure gas storage and refueling has the

advantages of being simple, very easy to use, commercially available, and capable of providing fast refueling (about 5 minutes)--advantages that no other hydrogen storage technique has. Although high-pressure storage of hydrogen is bulky, the high efficiency of the fuel cell reduces the amount of fuel that must be stored to travel a given distance, making high-pressure storage feasible. High-pressure storage (620 bar) is assumed here for the hydrogen FCV analysis.

Table 4 shows some of the important vehicle specifications used for ICEVs and the "comparable" FCVs used to define the base case in the following analyses of weight, bulk, efficiency, and lifecycle cost. The ICEVs and FCVs, while very similar (i.e., with respect to size, weight, capacity, and style), are not exactly comparable. In particular, it is assumed that the FCV has less peak power and a shorter range than the "comparable" gasoline ICEV vehicle. The peak power output of the FCV is assumed to be less than for an ICEV because extra power is very costly in a FCV (much more costly than in an ICEV), and it is well established that the peak power of gasoline ICEVs is virtually never used. Most drivers would never notice the lower peak power. Similarly, the range of the FCV is scaled down to what is considered the "minimum acceptable" range (not more than about 400 km, according to unpublished data from researchers at the University of California at Davis), because hydrogen storage systems are expensive and bulky. (It would not be costly to provide extra range in a methanol FCV. The range of the methanol FCV could easily be taken to be the same as for the methanol and gasoline ICEV, but instead it was decided to make the methanol and hydrogen FCVs as similar as possible, for purposes of comparison.) In sensitivity analyses discussed below, the lifecycle cost implications of making FCVs match the power of "comparable" gasoline ICEVs is indicated.

## Calculated Vehicle Characteristics

### *Weight*

Table 5 shows the calculated weights of the individual components of the FCVs, and the total extra weight of the FCV, compared to the gasoline ICEV, for the baseline vehicles of Table 4. The analysis indicates that a hydrogen or methanol FCV with a 400-km range will weigh up to about 60 kg more than the comparable gasoline vehicle. This weight increase is much less than that with BPEVs or hydride/hydrogen-powered ICEVs, which have very short ranges on account of their considerable extra weight. Thus, consideration of weight *per se* will not seriously affect the design or range of a FCV.

### *Bulk and range*

Fitting the fuel cell system--fuel cell, reformer, and fuel storage--into automobiles will be a challenge to vehicle designers. The fuel cell system would occupy 6-7 times more space than does the gasoline tank in an ICEV (Table 6). The methanol system is less bulky than the hydrogen system, because the added bulk of the reformer is less than the extra bulk of hydrogen storage, but the advantage is small. The compactness of the electric drivetrain compared to the complete ICE system (engine, fuel system, cooling system, electrical system, exhaust system, pollution control system, etc.) will alleviate the space problem somewhat, but it still is likely to be quite a challenge to fit the fuel cell system into a fuel cell electric vehicle designed from the ground up.

The bulkiness of the fuel cell system subtracts from the space available for passengers and luggage, and in the particular case of hydrogen restricts the range of the vehicle and forces the use of very high pressure storage, which is costly. For the purposes of the present analysis it is assumed that vehicles can be designed to accommodate the indicated fuel cell system volumes at relatively low cost.

### *System efficiencies*

Energy efficiencies are important parameters in comparing alternative systems for several reasons. The conversion efficiency of the vehicle (the ratio of the useful energy provided to the wheels to the fuel supplied to the vehicle) is a measure of the fuel required per km and the fuel contribution to the lifecycle cost. Total system efficiency (the ratio of the useful energy provided to the wheels to the energy of the biomass feedstock delivered to the gasification facility) is an indicator of both total greenhouse gas emissions and overall biomass requirements and thus land-use requirements for the system of motor vehicles operated on biomass-derived fuels. Here the relative overall efficiencies of methanol and hydrogen FCVs are discussed. Later the implications of efficiency will be incorporated into the lifecycle cost analysis and the discussion of greenhouse gas emissions and land use requirements.

A much-cited analysis by Kumar et al. (1989) indicates that a PEM system with a reformer has an overall efficiency (methanol to power) of 30%. Data from Ballard (1990) indicate an efficiency of 40-55% for hydrogen to power, depending on the operating point of the fuel cell, excluding energy used to compress air or circulate water. Assuming that pumping losses are 15% of gross power (Kumar et al., 1989), a midrange overall efficiency for hydrogen fuel cells would thus be about 40%.

Another paper by Kumar et al. (1988) states that a PEM fuel cell has a gross efficiency of 40.3% on methanol, including air compression, but excluding reforming and fuel vaporization. The efficiency with reforming and vaporization is 34.4%.

Advances in heat management and heat recovery, and low-energy designs for air compression, cooling, and water management, will improve the overall energy efficiency of both the methanol and the hydrogen fuel cell systems. Accordingly, for the present analysis it is assumed that a methanol fuel cell will be 37-38% efficient (methanol energy to net electricity to the motor), and that a hydrogen-only fuel cell will be about 44% efficient. The hydrogen fuel cell system thus will be about 17% more efficient than the methanol system, in relative terms.

The efficiency of the battery and drivetrain will be about the same in both vehicles. However, the hydrogen vehicle will weigh slightly more than the methanol vehicle, because of the heavier hydrogen storage tanks, and thus will be 1 to 2% less efficient.

Above, it was estimated that the production of biomass from hydrogen with the WM gasifier would be 63% efficient, and the production of methanol from biomass 54% efficient (Table 1). Overall, then, the hydrogen system will be about 34% more efficient than the methanol system. As discussed below, this has important implications for land-use requirements and emissions of greenhouse gases.

## **Safety**

For methanol and hydrogen to see widespread use as transportation fuels, policy makers and the public must be convinced that the new fuels are no more dangerous than the petroleum fuels they are accustomed to. Although there is some concern about certain properties of methanol (such as the possibility of a flammable concentration of vapor accumulating in the air space of a storage tank), the technical community generally agrees that methanol is no more dangerous than gasoline and in some respects is safer (Machiele, 1987). Because methanol is a liquid, and will be handled in much the same way that gasoline is today, motorists probably will react to it like they do to gasoline. A recent survey of driver reaction to methanol vehicles indicates that this indeed is likely to be the case (Sperling, 1991).

Gaining public acceptance of hydrogen probably will be harder, because hydrogen has a reputation of being a particularly dangerous fuel. However, the limited experience with hydrogen, and analyses of its physical and chemical properties, indicate that hydrogen is not necessarily more dangerous than gasoline, and, like methanol, is safer in some ways.

Hydrogen is more hazardous than gasoline in several respects. First, it is invisible and odorless, and therefore requires odorants and colorants to enable detection. Second, hydrogen flames are very hot, yet radiate very little heat and are invisible, which makes them harder to locate, and thus harder to extinguish or to avoid. Third, hydrogen can ignite within a rather large range of concentrations in air--from 4 to 74% (by volume). Compared to methanol or gasoline, it needs very little energy to ignite.

But hydrogen also has several safety advantages over gasoline. First, it requires much higher concentrations in air (18-59%) than gasoline (1-3%) to detonate. Second, because of its very low molecular weight, hydrogen, if leaked will disperse exceedingly quickly--unlike gasoline, which will puddle and remain a fire hazard much longer. Third, hydrogen fires radiate very little heat and burn quite rapidly and are relatively short lived; gasoline fires are much more persistent than hydrogen fires involving an equivalent amount of energy. Finally, hydrogen storage systems have been judged to be relatively safe (Strickland, 1978; Bockris, 1980; Huston, 1984; Peshcka, 1986).

Carbon-wrapped aluminum containers, assumed here for storage of hydrogen in FCVs, will have to undergo extensive safety testing before they can be certified. When hydrogen pressure vessels fail, they rupture, or tear, but do not shatter into fragments. Presently, the USDOT requires that commercial cylinders withstand gunfire without fragmenting, a bonfire without exploding, and several pressure cycling and thermal cycling tests. One manufacturer has found that dragging a compressed natural gas (CNG) cylinder from the back of a car, dropping it repeatedly onto a steel plate from 10 to 16 feet, partially cutting its fiber wrap, or leaving it pressurized outdoors for up to 11 years does not lower the burst pressure (Morris, 1986). The exterior of a composite high-pressure cylinder resists water, cleaning solvents, and salt air (SCI, 1986).

For the reasons cited above, the U.S. National Bureau of Standards (Hord, 1978), the Stanford Research Institute (Hoffman, 1981), and the German "Alternative Fuels for Road Transport" program (Quadflieg, 1986) have concluded that the hazards of hydrogen are different from, but not necessarily greater than, those presented by current petroleum fuels.

Though this judgment is shared by most of the hydrogen technical community, hydrogen fuel must also be regarded as acceptably safe by policymakers and by the general public before it can be widely used as a fuel. One recent study of public reaction to high-pressure natural gas storage tanks indicates that the use of high-pressure storage tanks integrated into the frame of a vehicle are not likely to be of serious concern to motorists (Sperling, 1991). However, to extend this favorable outlook to hydrogen, a wide range of demonstrations would be desirable, to show the safety of hydrogen in refueling, storage, and use in routine experience.

## **Environmental Impacts**

### *Urban air quality*

The great attraction of hydrogen FCVs is pollution-free operation. While many undesirable compounds are emitted from gasoline and diesel fuel vehicles or are formed in the atmosphere from the emitted compounds, a hydrogen FCV emits only water. Hydrogen FCVs do not produce CO, NMOCs, NO<sub>x</sub>, particulates, SO<sub>x</sub>, oxidants (such as ozone), carcinogenic aromatic compounds (such as benzene), toxic metals (such as lead), aldehydes, or greenhouse gases. They are environmentally superior even to hydrogen ICEVs, which produce some NO<sub>x</sub> as a result of the relatively high temperature of the internal-combustion engine (PEM fuel cells operate far below the temperatures required to produce NO<sub>x</sub>), and trace amounts of CO and HC from combustion of the lubricating oil. Only BPEVs can match the zero-emission performance of hydrogen-powered FCVs (Table 7).

Methanol FCVs will produce tiny amounts of NO<sub>x</sub> and CO from the reformer and a small amount of evaporated methanol from the fuel system. As shown in Table 7, these emissions are very small, although technically the evaporative emissions may disqualify methanol FCVs as "zero emission" vehicles.

### *Greenhouse gases*

The production, transport, and use of methanol and hydrogen derived from biomass will produce much less greenhouse gases, per kilometer of travel, than does the present gasoline production-and-use cycle. There are two reasons for the large reduction, relative to gasoline: (i) any CO<sub>2</sub> released from the production and use of a

biofuel does not count as a net emission to the atmosphere, because the carbon in the CO<sub>2</sub> comes originally from CO<sub>2</sub> in the atmosphere, via photosynthesis; and (ii) FCVs emit very little (methanol) or zero (hydrogen) non-CO<sub>2</sub> greenhouse gases.

However, methanol FCVs will produce noticeably greater greenhouse-gas emissions than hydrogen FCVs, when biomass is the feedstock. Because of its lower overall system efficiency (see discussion above), the biomass/methanol fuel cycle requires about 30 to 35% more primary biomass inputs than the biomass/hydrogen fuel cycle.<sup>10</sup> Thus, this much more biomass must be planted, fertilized, grown, harvested, and transported per unit of vehicle travel compared to hydrogen. This translates directly into greater emissions from the biomass production and transport stages (including emissions from the manufacture of fertilizer, and the denitrification of fertilizer to N<sub>2</sub>O), which account for most of total fuel cycle emissions from the use of biofuels (DeLuchi, 1991a).

In the long run, the greenhouse advantages of hydrogen over methanol are likely to grow. Because the production of biomass is land-use intensive and because the transport sector will be competing with other energy sectors for biomass supplies [especially the power sector (Williams and Larson, 1992)] biomass will probably not be able to meet the entire demand for transportation fuels, and supplemental energy sources will be needed.

For methanol, the most likely supplemental energy source is coal. But the use of coal to produce methanol for FCVs will result in about the same fuel cycle greenhouse gas emissions per kilometer as the use of gasoline in ICEVs (DeLuchi, 1991a; Fig. 5)--an unacceptable outcome if society decides to slow the rate of global warming.

In contrast, hydrogen can be made electrolytically from water using many non-fossil energy sources, including hydroelectric power, photovoltaic power (Ogden and Williams, 1989), wind power (Ogden and Nitsch, 1992), and nuclear power. Moreover, hydrogen can also be produced from coal with sequestering of the recovered CO<sub>2</sub> in gas wells (Blok et al., 1991). In this case the CO<sub>2</sub> emissions would be a tiny fraction of those from gasoline cars (Fig. 5). [Even if the separated CO<sub>2</sub> could not be sequestered,

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<sup>10</sup> In addition, methanol FCVs produce very small amount of non-CO<sub>2</sub> greenhouse gases (NO<sub>x</sub>, CO, and methanol), whereas hydrogen FCVs produce none. And if diesel-fuel trucks were used to transport methanol from production plants to service stations, they would also contribute modest additional greenhouse gas emissions; it is likely that biomass-fired power plants (Williams and Larson, 1992) located near the biomass-to-hydrogen production facility would provide the electricity needed to compress hydrogen for pipeline transport.



the high efficiency of hydrogen FCVs would lead to a 1/5 reduction in CO<sub>2</sub> emissions relative to gasoline cars (Fig. 5).] Of course the CO<sub>2</sub> produced at the methanol conversion plant could also be sequestered, but for this case, CO<sub>2</sub> emissions would be much larger than for hydrogen from coal (Fig. 5). From the standpoint of global warming, then, the biomass-to-hydrogen strategy is slightly more attractive than the biomass-to-methanol strategy in the short run, and considerably more attractive in the long run. Moreover, if other environmental impacts of coal mining (Chadwick et al., 1987) lead to restrictions on the use of coal, there are, as mentioned above, various alternative possibilities for providing additional hydrogen but not methanol.

### *Ecological concerns about biomass production*

The production of biomass for energy gives rise to a range of environmental concerns, including erosion, the adverse consequences of herbicide and fertilizer use, and the potential loss of biological diversity associated with such activities carried out on a large scale (Cook et al., 1991; Hall et al., 1991). While such concerns can often be addressed with careful planning (Hall et al., 1991), it is likely that some potential biomass supplies will not be developed for environmental reasons. In this regard the high efficiency of fuel cell cycles generally and the hydrogen fuel cell cycle in particular would make it possible for biomass to play very substantial roles in the overall energy economy, while respecting ecological constraints. This is illustrated by alternative scenarios for providing all US road transport energy requirements in the year 2030 with alternative biomass-derived fuel and vehicle technologies. If all road vehicles were ICEVs fueled with methanol derived from biomass in 2030, nearly all potential US biomass supplies would be required as fuel; but if instead all road vehicles were FCVs supplied with biomass-derived hydrogen, less than half the total potential supplies would be needed (Fig. 6).

### **Automotive Cost Comparisons**

It is widely believed that hydrogen's environmental advantages are outweighed by the high costs of hydrogen fuel and hydrogen vehicles. Indeed, a cost analysis by DeLuchi (1989) showed that hydrogen ICEVs will have much higher lifecycle costs than gasoline vehicles under most scenarios. But this conclusion does not necessarily apply to hydrogen-powered FCVs. In this section, the economics of FCVs are examined by making a detailed comparison of gasoline ICEVs and methanol and hydrogen FCVs.

Two summary cost-effectiveness parameters were calculated in this analysis--the total lifecycle cost and the break-even gasoline price.

The total lifecycle cost, expressed here in US cents (1990\$) per km of travel, is the sum of all annual operating costs and all annualized initial costs, divided by the distance (in km) traveled per year. Initial costs include costs of the basic vehicle (body, chassis, interior, and motor and drivetrain), the traction battery, the fuel cell, the reformer (for the methanol FCV), and the fuel storage system. Operating costs include fuel, insurance, maintenance, registration, inspection and maintenance, accessories, tires, and parking and tolls. Most of these initial and operating costs are functions of other parameters. For example, in the model used here (DeLuchi, 1991b), the fuel cost-per-km for the hydrogen FCV is a direct or indirect function of about 60 input parameters, and the cost of the fuel cell is a function of about 30 input parameters. The financial parameters used in this modeling exercise are summarized in Table 8.

The break-even price of gasoline is that retail price of gasoline, in dollars per gallon, obtained by equating the *total* cost-per-km of the gasoline vehicle (insurance cost, maintenance cost, tire cost, amortized initial cost, fuel cost... everything) and the *total* cost-per-km of the hydrogen vehicle.

The base case cost analysis (with biomass-derived fuels obtained using the WM gasifier) is summarized in Tables 6 and 9. There are three noteworthy results. First, both hydrogen and methanol FCVs have lower lifecycle cost-per-km and breakeven gasoline prices than hydrogen and methanol ICEVs (Table 6). Second, methanol FCVs probably will have a slightly lower lifecycle cost than hydrogen FCVs (Table 9). Third, with the base-case cost parameters used here, methanol and hydrogen FCVs would be roughly competitive with gasoline vehicles at the gasoline price projected for the year 2000--\$1.5 per gallon, including retail taxes (Table 9).

The superior outlook for biofuel-powered FCVs compared to biofuel-powered ICEVs reflects the inherent advantages of the fuel cell compared to the internal combustion engine, for fuels that can be used in both. The lower cost of the methanol FCV compared to the hydrogen FCV is due primarily to the high cost of hydrogen storage--adding nearly \$4,000 to the cost of the FCV (Table 5). The extra cost for hydrogen storage more than offsets differences between the two fuels in fuel retail price, vehicle efficiency, maintenance cost, insurance cost, and battery cost (Table 9). The prospect that biofuel-powered FCVs could be competitive with gasoline-fired ICEVs, despite the high initial cost of FCVs (Table 6) and the high cost of biofuels to the consumer (Table 3) is due mainly to three factors: the lower initial cost of the electric

drivetrain; the much higher efficiency of the fuel cell, compared to the IC engine; and (most importantly) the greater reliability and durability (longer life) of the electric drivetrain compared to the ICEV drivetrain (Table 4). The higher efficiency of the FCV not only reduces fuel costs [so much so that the cost-per-km of hydrogen or methanol in an FCV is lower than the cost-per-km of gasoline in an ICEV (Table 9)], but also reduces the amount of fuel that must be carried to provide a given range. This reduces the cost of the fuel storage system--especially important in the case of hydrogen. The greater reliability and durability of the electric drivetrain lowers the maintenance cost of the vehicle and dramatically lowers the amortized cost-per-km of vehicle ownership. These three cost advantages more than compensate for the extra cost of the fuel cell system in the FCV; the longer life of the electric drivetrain by itself nearly cancels all the cost disadvantages of the FCV.

It should be emphasized, however, that many of the important cost parameters involved are uncertain. Although the lowest cost estimates available for important components were generally not used in this analysis and no major technological breakthroughs were assumed, an underlying assumption is that the key battery, fuel cell, and hydrogen storage technologies will be developed, and that mass production will greatly reduce costs to levels that are being estimated or targeted for these components by industrial analysts. If any one of the most important FCV cost parameters is substantially underestimated, the breakeven gasoline price for the FCV would increase substantially (Table 10). The cost of the membrane in the fuel cell (case 1), the lifetime of the electric-drivetrain vehicle (cases 7 and 9), and the mark-up from manufacturing cost to retail price (case 12) are particularly important and uncertain. Also, if the FCV were required to have the same power as the gasoline vehicle (case 5), the breakeven gasoline price would increase to \$2.1 to \$2.3 per gallon. (Requiring the FCV to have the same range as the gasoline vehicle [560 km] would further increase the breakeven price for hydrogen FCVs but not for methanol FCVs because hydrogen storage is very expensive and methanol storage is virtually free.) Any combination of two or three of such unfavorable parameter changes would result in a much higher vehicle lifecycle cost than in the base case, and would make the fuel cell relatively unattractive.

But some key cost parameters assumed for the base case FCVs might also be overestimated. For example, biomass fuel production costs might turn out to be about 1/3 lower than the costs estimated for the WM gasifier (as might be the case for the BCL gasifier) (case 3). In this case the breakeven gasoline price would be \$1.1 per gallon for methanol FCVs (lower than the present gasoline price) and \$1.5 per gallon for hydrogen FCVs (approximately the gasoline price projected for the year 2000) (Table

10). Or the FCV lifetime might be 75% longer than for an ICEV (case 8: compared to 50% longer in the base case); in this case the breakeven price for gasoline would be reduced to \$1.1 for methanol FCVs and to \$1.4 for hydrogen FCVs. Experience with BPEVs suggests that vehicles with electric drives will last much longer than ICEVs; for example, electric milk vans in Britain reportedly last three times as long as comparable ICEVs (Bruner et al., 1987). If the production cost of biofuels were 1/3 lower, and if the FCV lasted 75% longer than the comparable ICEV (case 15), the breakeven gasoline price would be just \$0.8 for methanol FCVs and \$1.2 for hydrogen FCVs. Finally, if the environmental impacts of gasoline use were monetized and added to the price of gasoline, the economic balance might favor FCVs under a wide range of conditions.

## CHOOSING AN ENERGY CARRIER

Meeting all US road transport energy needs with petroleum in 2030 (Fig. 6) would require oil supplies amounting to more than 2.6 times expected domestic oil production at that time (EIA, 1991b) and give rise to CO<sub>2</sub> emissions of over 0.5 billion tonnes of carbon per year--equivalent to 36% of total US annual emissions from all fossil fuel sources in 1989. The same transport needs could be met largely with FCVs fueled with hydrogen or methanol derived from biomass, even with major constraints on biomass production and assuming significant demands for biofuels from other energy sectors (Fig. 6). Local air pollution and greenhouse gas emissions would be dramatically reduced with this alternative course. Moreover, these alternatives for road transport could be provided at costs that would certainly be affordable and may be competitive with gasoline-fueled ICEVs. This outlook does not depend on major technological breakthroughs, but it does require commitments on the part of government and industry to pursue radical changes in the road transport energy system.

In particular, since changing energy carriers requires costly infrastructure changes that will take a long time to bring about, considerable attention should be given to the choice of energy carrier, methanol or hydrogen, if a decision is made to pursue a road transport system based on the use of FCVs operated on biofuels.

A methanol fuel cell system would have two major advantages over a hydrogen fuel cell system. First, methanol FCVs would probably have lower lifecycle costs and longer ranges than hydrogen FCVs, because of the high cost of hydrogen storage. Second, it would be easier to introduce methanol, because it is a liquid energy carrier that can be handled by essentially the same distribution, storage, and refueling

infrastructure now used for gasoline and diesel fuel. These advantages must be weighed against methanol's principal disadvantages. One is the fact that the lower overall energy efficiency for providing methanol from biomass would lead to greater land use requirements for biomass production and thus greater potential environmental conflicts than would be required to provide the same transport needs with a hydrogen system. Another is the likelihood that biofuels alone will not be able to meet all future energy requirements for the transport sector (both because of environmental constraints and competing demands for biofuels), and the fact that there is no feedstock for methanol production other than biomass that is also domestically abundant, affordable, and characterized by low pollutant and greenhouse gas emissions, while there are many such possibilities for hydrogen.

The choice between these alternative energy carriers is not clearcut. Indeed it may be practical to launch a shift to biofueled FCVs using both carriers, as appropriate in different applications, and to delay making a choice between them until later. The choice, and the timing of the decision, depend largely on society's vision of the most desirable mix of energy sources for transportation and of how quickly and at what cost that mix should be achieved.

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Table 1. Comparison of production costs (1990\$) of methanol and hydrogen from biomass for units processing 3000 green tonnes (1650 dry tonnes) per day of biomass.<sup>a</sup>

	Methanol	Hydrogen
<b>Capital costs (10<sup>6</sup> \$)</b>		
Feed preparation <sup>b</sup>	5.76	5.76
Gasifier <sup>c</sup>	64.0	64.0
Reformer <sup>d</sup>	16.9	16.9
Vessels/exchangers/pumps/filters <sup>d</sup>	9.4	9.4
Carbon dioxide removal <sup>e</sup>	14.3	--
Pressure swing adsorber <sup>f</sup>	--	18.0
Methanol synthesis & compressor <sup>g</sup>	50.0	--
Hydrogen compressor <sup>h</sup>	--	4.50
Utilities/auxiliaries <sup>b</sup>	40.1	28.0
Subtotal	200.5	139.8
Contingencies (20%)	40.1	28.0
Owners costs, fees, profits (10%)	20.0	14.0
Startup <sup>b</sup>	6.65	6.65
Total investment capital	269.5	201.5
Working capital	20.1	14.8
Land <sup>b</sup>	2.21	2.21
<b>Variable operating costs (10<sup>6</sup> \$/yr)</b>		
Feed	28.3	28.3
Catalysts & chemicals <sup>b</sup>	2.78	2.78
Total	31.1	31.1
<b>Fixed operating costs (10<sup>6</sup> \$/yr)</b>		
Labor <sup>b</sup>	1.13	1.13
Maintenance (3% of cc subtotal) <sup>i</sup>	6.01	4.45
General overhead (65% lab/maint.) <sup>i</sup>	4.64	3.62
Direct overhead (45% of labor) <sup>i</sup>	0.51	0.51
Total	12.29	9.71
<b>Annual production (10<sup>6</sup> GJ/yr)</b>	6.12	7.14
<b>Levelized costs (\$/GJ)</b>		
Capital <sup>i</sup>	7.01	4.50
Labor, maintenance, chemicals	2.46	1.75
Biomass	4.63	3.97
Total	14.10	10.22

(a) Assuming: Wright-Malta gasification technology; processing plants operated at 90% average capacity factor; the processing of wet (45% moisture content) biomass costing \$2.5/GJ; and conversion efficiencies of 54% and 63%, respectively, for producing methanol and hydrogen from biomass; a higher heating value of wet biomass of 11.5 GJ/t.

(b) Based on (Wyman, et al., 1992).

(c) Based on (Coffman, 1991).

(d) Based on (Kessler, 1991).

(e) Based on (Epps, 1991).

(f) Based on (Soloman, 1991).

(g) Based on (Mansfield, 1991).

(h) Assuming a unit compressor cost of \$700 per kW of capacity.

(i) Based on (OPPA, 1990).

(j) Assuming: average financial parameters for major US corporations in the period 1984-88 (9.9% real rate of return on equity, 6.2% real rate of return on debt, a 30% debt fraction, a 44% corporate income tax rate); a property tax and insurance rate of 1.5% per year; and a 25-year plant life. For these parameters the levelized capital charge rate for plant and equipment is 15.1% per year. For land and working capital the annual capital charge rate is taken to be 9.9% per year, the corporate discount rate.

Table 2. Comparison of methanol production costs (1990 \$/GJ) for alternative technologies.

	Biomass Gasifiers			Texaco Gasifier with Coal <sup>b</sup>
	WM	IGT <sup>a</sup>	BCL <sup>a</sup>	
Capital <sup>c</sup>	7.01	5.34	3.74	4.95
Feedstock <sup>d</sup>	4.63	4.38	3.62	2.95
O&M	2.46	2.35	2.19	1.52
<b>Total</b>	<b>14.10</b>	<b>12.07</b>	<b>9.55</b>	<b>9.42</b>

- (a) Based on analyses for the Institute of Gas Technology (IGT) oxygen-blown gasifier and the Battelle-Columbus Laboratory (BCL) gasifier carried out at the Solar Energy Research Institute (Wyman, et al., 1992), adjusted to conform to the financial assumptions and the biomass feedstock cost assumptions of the present study.
- (b) Based on an analysis of the Texaco oxygen-blown, entrained-flow gasifier (OPPA, 1989), adjusted to conform to the financial assumptions of the present study.
- (c) In all cases the annual capital charge rate is assumed to be 15.1% per year for plant and equipment and 9.9% per year for land and working capital. Property taxes and insurance (assumed to be 1.5% of the plant and equipment investment per year) are included in the capital charge rate for plant and equipment.
- (d) The biomass feedstock cost is assumed to be \$2.5/GJ for all three biomass gasifiers. The cost of coal is assumed to be \$1.48/GJ (OPPA, 1989).

Table 3. Levelized costs to consumers of alternative fuels (in \$/GJ).

	Fuels Derived From Biomass				
	Gasoline	Meth- anol	Gaseous hydrogen hydride for ICE	Comp- ressed hydrogen gas for fuel cell	Liquid hydro- gen <sup>i</sup>
<b>Production<sup>a</sup></b>					
Feedstock	4.55 <sup>b</sup>	4.63	3.97	3.97	4.35
Capital	-- <sup>c</sup>	7.01	4.50	4.50	4.93
O&M	-- <sup>c</sup>	2.46	1.75	1.75	1.92
Subtotals	7.58 <sup>b</sup>	14.10	10.22	10.22	11.20
<b>Distribution</b>	0.98 <sup>d</sup>	1.90	0.95	0.95	0.78 <sup>e</sup>
<b>Liquefaction</b>	--	--	--	--	6.04 <sup>f</sup>
<b>Retail margin<sup>l</sup></b>	0.61 <sup>d</sup>	1.17	1.99 <sup>g</sup>	3.52 <sup>g</sup>	4.92 <sup>h</sup>
<b>Total cost to consumer<sup>i</sup></b>					
(\$/GJ)	9.17	17.17	13.16	14.69	22.94
(\$/gal. gasoline-equiv.)	1.21	2.26	1.74	1.94	3.03

- (a) Entries for biomass fuels are from Table 1 (based on the use of the WM gasifier).
- (b) Assuming: refiner crude oil acquisition cost of \$27.8/barrel, as projected for 2000 by the US Department of Energy (EIA, 1990a), with 0.9 of a barrel used for gasoline; a cost of \$0.25/gal for standard gasoline refining (based on the difference between the refinery wholesale price and the refinery crude oil acquisition price (EIA, 1990b); an additional cost of \$0.15/gal for reformulated gasoline (Boekhaus et al, 1990); a heating value of 0.1319 GJ/gal for gasoline.
- (c) The capital and O&M costs are not estimated separately for gasoline.
- (d) From Dougher and Jones (1990).
- (e) Estimated to be 25% less than for the gaseous hydrogen fuel cases, because the liquefaction plant is near a hydrogen trunk line--i.e. no local gaseous fuel distribution to refueling station.
- (f) Estimated electricity requirements for liquefaction are 0.26 GJ per GJ of hydrogen, so that electricity for liquefaction costs \$3.61/GJ [for electricity at \$0.05/kWh, the projected industrial electricity price in 2000 (EIA, 1990a)]; other liquefaction costs are \$1.90/GJ.
- (g) At refueling station, hydrogen from the distribution line at 3.4 bar is compressed to 51 bar for transfer to the cars' metal hydride storage tanks that are pressurized to 34 bar, and to 680 bar for transfer to hydrogen storage cylinders in cars containing hydrogen compressed to 620 bar.
- (h) The cost of truck transport to refueling station, \$1.01/GJ, plus refueling station markup, \$3.92, including liquid hydrogen transfer losses [see note (i)].
- (i) Includes estimated liquid hydrogen losses of 3% at each transfer point (liquid hydrogen to truck, truck to refueling station, station to customer's car).
- (j) Does not include retail gasoline tax (\$0.29/gallon of gasoline).



Table 4. Characteristics of vehicles in the analysis.<sup>a</sup>

Vehicle type ==>	Internal Combustion Engine				Proton Exchange Membrane Fuel Cell/AC Electric Motor	
	Gasoline METAL TANK	Methanol METAL TANK	Gaseous Hydrogen FE-TI HYDRIDE	Liquid Hydrogen CRYOGENIC DEWAR	Methanol METAL TANK	Hydrogen CARBON-WRAPPED ALUM. PRESSURE VESSEL (620 BAR)
Peaking battery	N.A.	N.A.	N.A.	N.A.	BIPOLAR LITHIUM-ALLOY/IRON-DISULFIDE	
Maximum power at wheels (kw)	67	67	67	67	45	45
Driving range (km)	560	560	240	400	400	400
Vehicle life (1000 km)	193	193	222	222	290	290
Fuel economy (mpg of gasoline equivalent)	30.0	34.5 <sup>b</sup>	33.0 <sup>c</sup>	38.8 <sup>d</sup>	53.5 <sup>e</sup>	61.4 <sup>e</sup>

(a) All vehicles are compact cars. N.A. = not applicable;

(b) Assuming that methanol is 15% more thermally efficient than gasoline, due primarily to the use of a higher compression ratio, and that the new 0.25 gm/km NO<sub>x</sub> standard precludes use of lean burning, which would further increase methanol's efficiency advantage.

(c) Assuming a 27% thermal efficiency advantage over gasoline, due to lean burn and the use of a high compression ratio. (Hydrogen vehicles will probably be able to use lean burn and still meet the new 0.25 gm/km NO<sub>x</sub> standard.) The value shown accounts for the efficiency effect of the extra weight of the hydrogen vehicle.

(d) Assuming a 30% efficiency advantage over gasoline (slightly higher than for gaseous hydrogen used in hydrides because of the cooling effect of the cold liquid hydrogen). The value shown accounts for the efficiency effect of the extra weight of the hydrogen vehicle. The value shown is miles per gasoline-equivalent gallon delivered to the vehicle; that is, it does not account for upstream hydrogen boiloff. The value in miles per gasoline-equivalent gallon produced at the liquid hydrogen facility would be 35.4 (38.8x0.97<sup>3</sup>); three transfers with 3% losses at each.)

(e) The fuel cell/electric motor system (without a reformer) is about 2.1 times more efficient than the ICE system. The reformer reduces the efficiency of the fuel cell system by about 15%. The values shown account for the extra weight of the fuel cell vehicles.

Table 5. Weight, volume, and initial cost of fuel cell vehicle components.<sup>a</sup>

Item	Retail Prices (\$) <sup>b</sup>		Weight (kg)		Volume (liters) <sup>c</sup>	
	Methanol	Hydrogen	Methanol	Hydrogen	Methanol	Hydrogen
Traction battery	3,594	3,469	68	63	19	17
Fuel storage, incl. valves, regulators, etc.	40	3,909	22 <sup>d</sup>	88 <sup>d</sup>	35 <sup>e</sup>	143 <sup>e</sup>
Fuel cell stack and associated auxiliaries	2,390	2,390	74	74	127	127
Methanol reformer and associated auxiliaries	577	0	36	0	64	0
Extra support structure on alternative-fuel vehicle	6	11	2	4	N.E.	N.E.
Difference between electric and ICE power trains <sup>f</sup>	-795	-795	-166	-166	N.E.	N.E.
Complete alternative-fuel vehicle	17,812	20,984	1,164	1,191	N.E.	N.E.
Complete gasoline vehicle	12,000	12,000	1,128	1,128	N.E.	N.E.
Difference between complete vehicles	5,812	8,984	36	63	N.E. <sup>g</sup>	N.E. <sup>g</sup>

(a) Values from model documented by DeLuchi (1991b). N.E. = not estimated.

(b) Retail price includes license and all mark-ups and taxes, including sales tax.

(c) Water volumes of components only. Does not include volume required to package the various components or unuseable space between and around components.

(d) Fuel system and vehicle weights for half-full storage tank.

(e) Fuel storage system volume does not include fuel lines, valves, regulators, etc.

(f) The electric power train consists of all EV-specific parts except the battery, fuel cell and reformer system, and fuel storage. The ICE power train includes all parts removed from ICEV, including pollution control equipment.

(g) Could not be estimated due to difficulty of determining water displacement volume of engine, transmissions, fuel system, exhaust system, pollution control, electronics, etc., in a modern vehicle. Note, though, that an electric power train requires much less space than an ICE power train.

Table 6. Summary of weight, volume, and cost results.<sup>a</sup>

Vehicle type ==>	Internal Combustion Engine -----			Proton Exchange Membrane Fuel Cell/AC Electric Motor		
	Gasoline <sup>b</sup>	Methanol <sup>c</sup>	Gaseous Hydrogen Hydride <sup>d</sup>	Liquid Hydrogen <sup>d</sup>	Methanol <sup>b</sup>	Hydrogen <sup>b</sup>
Vehicle weight (kg)	1128	1128	1,382	1,136	1,164	1,191
Fuel storage/processing volume (liters)	47	N.E.	N.E.	N.E.	278	317
Fuel retail price (\$/gallon gasoline-equivalent) <sup>f</sup>	1.21	2.26	1.74	3.03 <sup>e</sup>	2.26	1.94
Full vehicle retail price, with taxes (\$)	12,000	12,000	16,351	13,248	17,812	20,984
Maintenance cost (\$/yr)	444	444	400	400	330	311
Breakeven gasoline price (\$/gallon) <sup>g</sup>	N.A.	2.34	2.66	2.53	1.43	1.66

(a) N.A. = not applicable; N.E. = not estimated.

(b) Results for the fuel cell vehicles and the gasoline ICEV are based on the analysis outlined here and detailed by DeLuchi (1991b).

(c) Results for the methanol ICE vehicle are based in part on the analysis in DeLuchi, et al. (1988).

(d) Results for the hydride and liquid hydrogen ICE vehicles are from an updated version of the analysis described by DeLuchi (1989).

(e) Accounts for boil-off of liquid hydrogen when it is transferred from one container to another.

(f) Excludes retail taxes.

(g) Includes retail taxes.

Table 7. Percentage change in gm/km emissions from alternative-fuel vehicles, relative to gasoline.<sup>a</sup>

Fuel/vehicle	NMOC	CO	NO <sub>x</sub>	O <sub>3</sub>	SO <sub>x</sub>	PM
Methanol/ICEV (w/catalyst)	-50	0 <sup>b</sup>	0	-50	-100 <sup>c</sup>	lower
Hydrogen/ICEV (no catalyst)	-95	-99	? <sup>d</sup>	-95	-100 <sup>c</sup>	lower
Methanol/fuel cell	-90 <sup>e</sup>	-99 <sup>f</sup>	-99 <sup>f</sup>	-90	100 <sup>c</sup>	-100
BPEV (solar power)	-100	-100	-100	-100	-100	-100
Hydrogen/fuel cell	-100	-100	-100	-100	-100 <sup>c</sup>	-100
Baseline gm/km emissions from gasoline ICE vehicle <sup>g</sup>	0.48	3.81	0.28	N.A.	0.03 <sup>h</sup>	0.01

- (a) From (Sperling and DeLuchi, 1991), except for methanol/fuel cell. These are rough estimates only, assuming advanced-technology, single-fuel cars, and in the case of ICEVs, emission control and engine operation designed to meet a NO<sub>x</sub> standard, which will be the most difficult standard to meet. NMOC = nonmethane organic compounds. PM = particulate matter. N.A. = not applicable.
- (b) CO emissions depend very strongly on the air/fuel ratio. It appears that ICE vehicles will have to operate very near stoichiometric to meet the new US 0.25 gm/km (0.40 gm/mile) NO<sub>x</sub> standard. (Reduction catalysts do not work in an oxygen-rich environment.) At or near stoichiometric operation, methanol vehicles will emit about as much CO as gasoline vehicles.
- (c) Assuming that the fuel is pure methanol or pure hydrogen, and hence contains no sulfur. Actual SO<sub>x</sub> emissions will depend on the amount of sulfur in the fuel.
- (d) It is possible that ultra-lean operation, which can be done with hydrogen, could greatly reduce and even eliminate NO<sub>x</sub> emissions. This has not been demonstrated in drive-cycle tests, however.
- (e) Not a 100% reduction because of evaporative emissions of methanol from methanol storage, distribution, and refueling (DeLuchi, 1991a; DeLuchi, et al., 1991).
- (f) There would be very minor emissions from the methanol reformer. Data and statements in Zegers (1990), Patil, et al (1990), Kevala (1990), and Werbos (1987) indicate that these emissions would be on the order of 1% of the emissions from a gasoline ICEV. The very low temperature of the PEM fuel cell assumed here is insufficient for formation of NO<sub>x</sub>.
- (g) Emissions from a vehicle operating on reformulated gasoline and meeting 1990 Clean Air Standards in year 2000 (DeLuchi, 1991a).
- (h) Assuming gasoline is 0.03% sulfur by weight, the vehicle gets 7.84 lit/100 km (30 mpg), and all sulfur oxidizes to SO<sub>2</sub>.

Table 8. Financial parameters used in the motor vehicle analysis.

<b>Financing new car purchases</b>	
Fraction of new car buyers who take out a loan to buy a new gasoline vehicle	0.70
Fraction of new car buyers who take out a loan to buy a new fuel cell vehicle	0.90 <sup>a</sup>
Downpayment on the car (fraction of full selling price)	0.10
Length of financing period for gasoline cars bought on loan (months)	54
Length of financing period for fuel cell cars bought on loan (months)	60 <sup>a</sup>
Real annual interest rate on loans for buying a new gasoline car, before taxes	0.080
Real annual interest rate on loans for buying a new fuel cell car, before taxes	0.090 <sup>a</sup>
Real annual discount rate, for all consumer expenditures on transportation, before taxes	0.040
Effective (average) income tax rate (for evaluating interest deductions)	0.18
<b>Mark up from original equipment manufacturer to retail level</b>	
Automotive division mark up (over materials, labor, operating cost)	1.20
Mark up from division level to factory level	1.25
Dealer mark up, excluding sales tax and shipping	1.20
Mark up to account for cost of shipping vehicle from factory to dealer	1.02
Sales tax mark up	1.06
<b>Financing parameters for refueling station cost calculation</b>	
Insurance and property tax (fraction of total investment per year)	0.020
Real rate of return on investment, after taxes	0.09
Real rate of interest on loan, before taxes (assume period of loan = life of equipment)	0.07
Corporate income tax rate	0.44
Fraction of initial investment financed by loan	0.50
Life of station--building and all equipment (years)	20

(a) The loan rate, loan period, and fraction of buyers taking out a loan are assumed to be higher with fuel cell vehicles than with gasoline ICEVs, because the fuel cell vehicles will cost several thousand dollars more than the gasoline vehicles.

Table 9. Total lifecycle cost components of gasoline ICE vehicle and methanol and hydrogen FC vehicles.<sup>a</sup>

Cost Component	Total Lifecycle Cost (cents per kilometer)	
	Gasoline	Methanol Hydrogen
Purchased electricity (after regenerative braking)	--	0.08
Vehicle, excluding battery, fuel cell, and hydrogen storage	7.68	5.32
Battery	--	1.88
Fuel cost (excluding retail taxes)	2.50	2.37
Hydrogen or methanol storage	--	0.01
Fuel cell (including reformer, if any)	--	1.07
Insurance (a function of vehicle value and km traveled)	2.54	2.91
Maintenance	2.49	1.56
Oil	0.06	0.00
Replacement tires (a function of vehicle weight and km traveled)	0.25	0.33
Parking and tolls	0.50	0.50
Registration (a function of vehicle weight)	0.14	0.12
Inspection and maintenance	0.22	0.09
Retail fuel tax <sup>c</sup>	0.60	0.60
Accessories	0.11	0.11
<b>TOTAL CONSUMER LIFECYCLE COST (CENTS/KILOMETER)</b>	<b>17.10</b>	<b>16.97</b>
<b>Breakeven price of gasoline, including taxes (\$/gallon)<sup>b</sup></b>	<b>N.A.</b>	<b>1.43</b>

(a) From the lifecycle cost model of DeLuchi (1991b). N.A. = not applicable.

(b) Price of gasoline at which the lifecycle consumer cost of the gasoline vehicle equals that of the fuel cell vehicle.

(c) Assumed to be the same for all cases, on a per-kilometer basis. A gasoline tax of \$0.29/gallon is equivalent, for a 30 mpg car, to 0.6 cents/km.

Table 10. Sensitivity of breakeven gasoline price to important cost parameters.<sup>a</sup>

Case	Parameter and sensitivity examined	Breakeven Gasoline Price (\$/gallon)		Case
		Methanol	Hydrogen	
0)	Base case results (Table 9)	1.43	1.66	(0)
1)	Cost of proton exchange membrane (membrane only) four times higher (\$322/m <sup>2</sup> )	2.03	2.26	(1)
2)	Cost of biomass feedstock 100% higher (\$5/GJ)	1.74	1.89	(2)
3)	Total cost of fuel production 33% lower <sup>b</sup>	1.12	1.46	(3)
4)	Electric drivetrain 3.8 times more efficient than ICEV drivetrain (4.4 times in base case)	1.69	1.98	(4)
5)	Max. power required at wheels of 67 kW--same as gasoline vehicle (45 kW in base case)	2.05	2.29	(5)
6)	EV drivetrain cost the same as ICEV drivetrain (\$750 less in base case)	1.64	1.86	(6)
7)	Fuel cell vehicle lifetime km traveled 25% higher than gasoline vehicle (50% higher in base case)	1.98	2.20	(7)
8)	Fuel cell vehicle lifetime km traveled 75% higher than gasoline vehicle (50% higher in base case)	1.12	1.36	(8)
9)	Fuel cell vehicle lifetime same as gasoline vehicle's (50% higher in base case)	2.88	3.12	(9)
10)	Fuel cell vehicle per-km maintenance costs same as gasoline vehicle	1.78	1.99	(10)
11)	Price of methanol reformer 50% higher than base case	1.50	--	(11)
12)	Ratio of selling price to manufacturing cost is 2.5 (1.95 in base case)	1.88	2.26	(12)
13)	Price of hydrogen refueling 50% higher than base case	--	1.76	(13)
14)	Price of hydrogen container 50% higher than base case	--	2.01	(14)
15)	Cases 3 and 8 combined	0.81	1.16	(15)
16)	Cases 3, 5, and 8 combined	1.46	1.83	(16)

(a) The breakeven price of gasoline is the retail price of gasoline, including sales taxes, at which the full lifecycle cost of the gasoline vehicle equals the full lifecycle cost of the fuel cell vehicle.

(b) Corresponding to the estimated cost of producing fuel using the Battelle-Columbus Laboratory gasifier (see Table 2 and text).

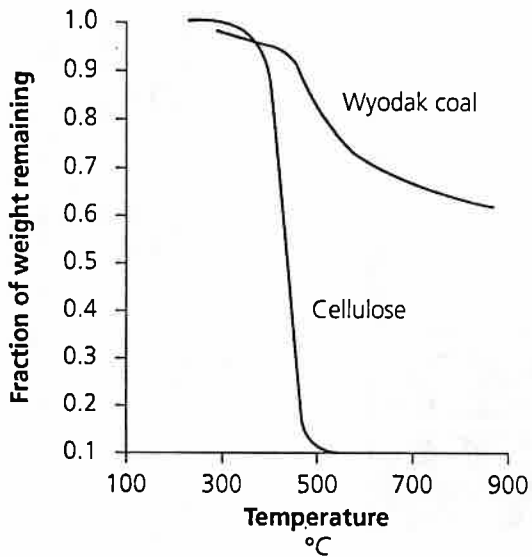


Fig. 1. Weight loss as a function of temperature during pyrolysis of coal and cellulose, a major component of biomass (Antal, 1980)

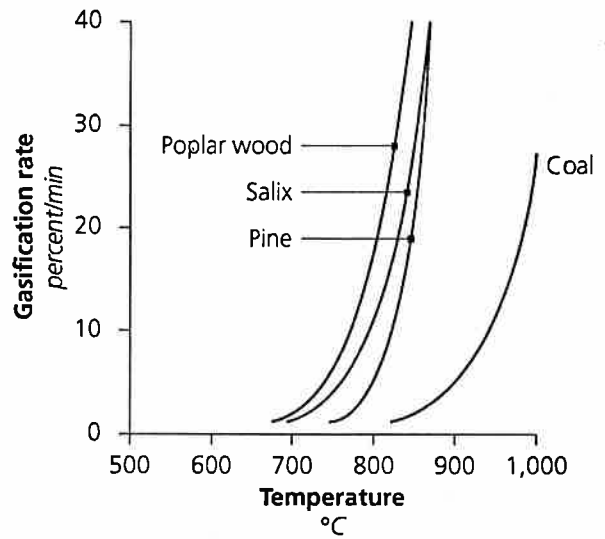


Fig. 2. Gasification rates in steam of chars from coal and several biomass feedstocks (Waldheim and Rensfelt, 1982).

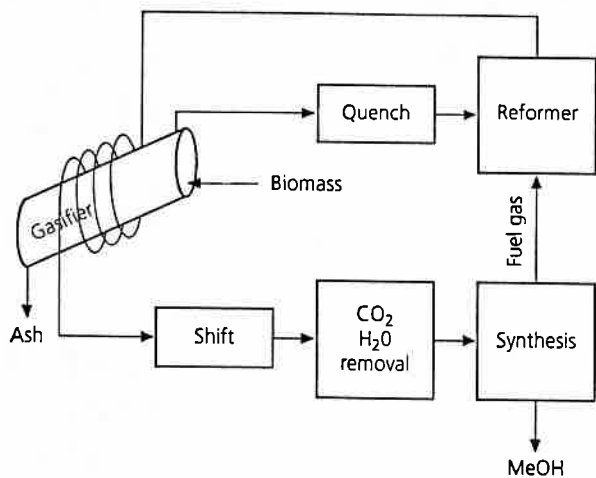


Fig. 3. Conceptual process schematic for production of methanol from biomass based on the Wright-Malta gasifier.

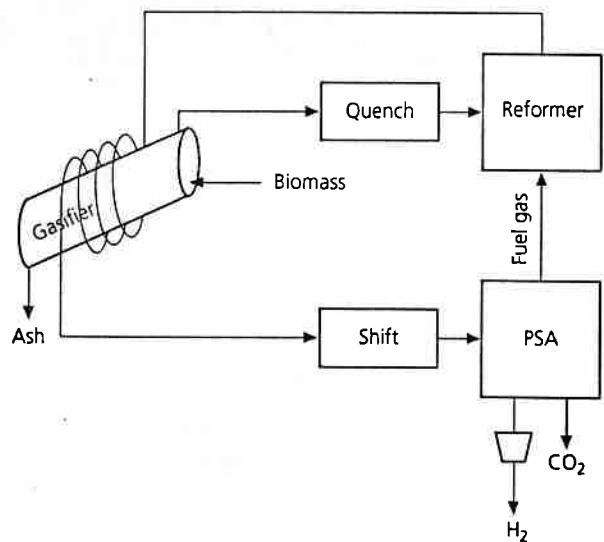


Fig. 4. Conceptual process schematic for the production of hydrogen from biomass based on the Wright-Malta gasifier.



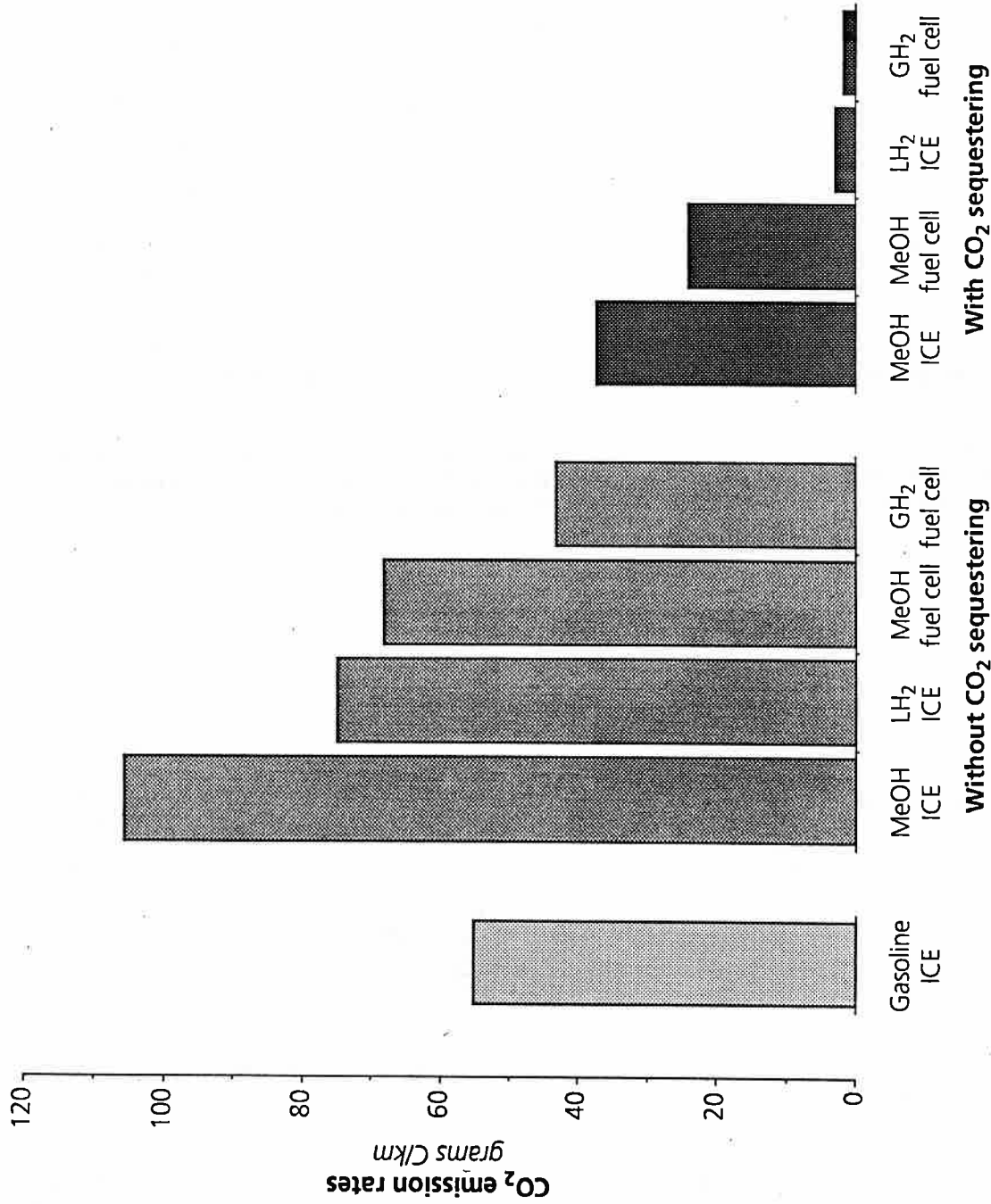


Fig. 5. Carbon dioxide emission rates for gasoline ICEVs (left bar) and for alternative coal-based methanol and hydrogen ICEV and FCV options, assuming the automotive fuel economies listed in Table 4. The four bars on the right refer to cases where the CO<sub>2</sub> separated from the fuel at the fuel conversion facility is sequestered in depleted natural gas wells, while the other four bars refer to cases where the separated CO<sub>2</sub> is vented. For hydrogen production with sequestering it is assumed that 88% of the carbon in the coal can be sequestered (Blok et al., 1991) and that the byproduct fuel gas (containing the rest of the carbon, mainly as CO) displaces natural gas, so that only emissions in excess of what they would have been had natural gas been used are charged to hydrogen. (Without taking this credit, the emission rate for hydrogen FCVs would be about 1/10 the rate for gasoline.) It is estimated that methanol production from coal is 56% efficient and that 65% of the carbon in the coal can be recovered at the methanol plant for sequestering, assuming that methanol production is based on the use of a Texaco gasifier (OPPA, 1989).

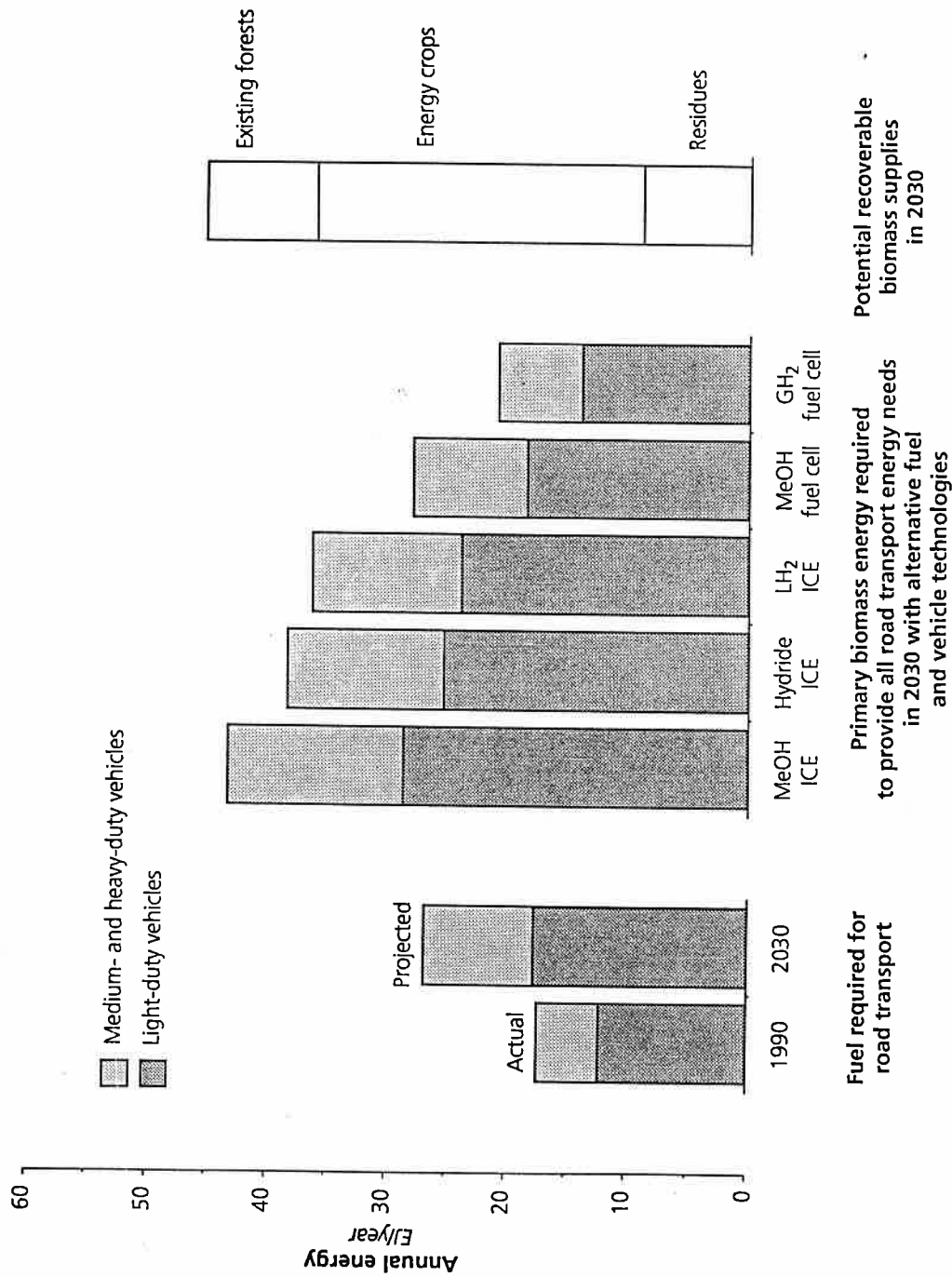


Fig. 6. Primary biomass energy requirements to provide the entire energy requirements for the US road transport sector in 2030, for alternative combinations of fuels (methanol and hydrogen) and motor vehicles (ICEVs and FCVs). On the left for comparison are shown the 1990 and year 2030 energy requirements for road transport if based on petroleum, as projected for the EIA's reference case (EIA, 1990c). The EIA projects: that light-duty and medium-heavy-duty vehicle travel will increase from 2.84 and 0.51 trillion vehicle km in 1990, to 5.42 and 1.09 trillion km in 2030, respectively, and that the average on-the-road fuel economy will increase in this period from 19 to 25 mpg for light-duty vehicles and from 8 to 10 mpg for medium-heavy-duty vehicles. Biomass energy production efficiencies are assumed to be 54% and 63%, for methanol and hydrogen, respectively. The gasoline-equivalent fuel economies for the various alternative fueled-vehicles are taken to be in the same ratio to gasoline ICEVs as in Table 4. The bar on the right indicates potential US biomass supplies in 2030. "Residues" include estimated forest-product-industry and agricultural residues that could be recovered in environmentally acceptable ways, as well as urban refuse, while the potential contribution from "existing forests" refers to what could be obtained from commercial forests with improved forest management (Fulkerson et al., 1989). The amount of biomass that could potentially be obtained from "energy crops" is based on the use of 78 million hectares of cropland and potential cropland producing biomass at an average yield of 20 dry tonnes per hectare per year (INEL, 1990).

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