As suggested above, the total-value or total-energy-content approach assumes that the uses and things that the by-products replace would have consumed as much energy — and the same kind of energy — as did the production of the by-products.* Neither assumption is likely to be exact. Certainly, there is no reason to believe that the amount and kind of energy used to make the things displaced by ethanol by-products are at all similar to the amount and kind of energy used to make the by-products. This method probably describes an upper limit to the energy and emissions credit that can be assigned to ethanol production.

Finally, note that the counterfactual-type analysis (comparison of the with-ethanol world and the without-ethanol world) can produce interesting results. For example, increased demand for corn ethanol may not translate into increased planting and farming of corn: the ethanol may be made by diverting to a distillery corn starch that already is being used as an animal feed, and the lost animal feed then made up by increased use of forage or some grain other than corn. Thus, in this case, the net effect of an ethanol policy is an increase in the production of something other than corn as an animal feed. I have not considered such scenarios here.

K.3 Energy Used to Make Methanol, Ethanol, Synthetic Natural Gas, and Gasoline from Wood

Wood is potentially a much more abundant bio-energy feedstock than crops. In 1985, the USDOE projected that energy from conversion of trees to ethanol, methanol, or gas could supply about 5.7 quads of energy 2010, considerably more than any other biomass source (excluding direct combustion of wood) (Klass, 1987). These trees would be grown in a system known as short-rotation intensive-cultivation (SRIC), designed to maximize wood production and minimize cost. The trees would be fast growing, closely spaced, and harvested frequently (hence the name SRIC), to ensure a large and continuous supply of feedstock (see Ranney et al. 1987, for a review). Several researchers have investigated the energy and material input to SRIC (these are reviewed below).

Wood can be gasified and cleaned up to produce a substitute, medium-Btu NG; gasified and then converted to methanol, via normal methanol synthesis; or hydrolyzed by enzymes and converted to methanol. Energy-use data are available for all three routes, and all are analyzed in this report.

Energy and greenhouse gas accounting for wood-based biofuels is relatively straightforward, compared to corn to ethanol. Essentially all of the wood is consumed at plant,

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* Note that it is the amount and kind of energy that would have been consumed by the things replaced by the by-products, and not the energy used by the by-products themselves, that is of interest. This is because if we make the ethanol, we end up with emissions from the ethanol process, but have eliminated the emissions from the processes associated with the things displaced by the ethanol by-products. Thus, the net increase in emissions in the with-ethanol world compared to the without-ethanol world is emissions from ethanol production less emissions from processes displaced by ethanol by-products. (Gasoline is treated separately).

either as process fuel or feedstock for methanol or SNG, and are no major by-products. Two minor difficulties are fertilizer use for SRIC, and oxygen use at conversion plants.

K.3.1 Energy Used in Silvicultural Operations

Energy is used to plant, irrigate, fertilize, harvest, dry, transport trees, and to make the equipment used in these operations. Generally, less energy is used in silviculture than in corn farming, per unit of fuel ultimately provided, because trees require less fertilization and irrigation than does corn, and require little much management while they are growing.

Table K.9 shows estimates of the energy inputs to silviculture, per unit of wood energy available. These estimates are in reasonable agreement, and they show that silviculture is much less energy intensive than agriculture. I have broken the total energy estimates of Table K.9 into five items: fertilizers, irrigation, physical equipment, drying, wood transport, and other (planting and harvesting, primarily). Energy embodied in equipment is small and is ignored. Energy for transport and drying are separated from energy for harvest.

Fertilizers (especially nitrogen fertilizers) are relatively energy intensive, and so one's assumption about fertilizer use in SRIC will noticeably affect calculated total emissions of greenhouse gases from the production of wood-fuels. Unfortunately, there is enormous variability in the amount of fertilizer required in SRIC: some sites will not need any, and some sites will need a lot. Table K.10 summarizes a few estimates or records of fertilizer use in SRIC. Blankenhorn et al. (1985) applied large amounts of fertilizer to their test plots, but also found that unfertilized sites produced nearly as much wood as fertilized sites, if weeds were controlled (Ranney et al. 1987, confirm this). In a personal communication to me, Turhollow (1989) claims that much less fertilizer will be in SRIC than was used by Blankenhorn et al. Klass (1987) lists 6 SRIC experiments which did not use fertilizer.

An additional complication is whether or not lime will be used. Blankenhorn et al. (1985) applied lime, but I have not seen mention of it elsewhere. Although little energy is required to make a pound of lime, Blankenhorn et al. applied a huge amount and, moreover, the manufacture of lime from calcium carbonate drives off CO_2:

$$CaCO_3 \xrightarrow{\text{heat}} CaO + CO_2$$

The model calculates these CO_2 emissions; they turn out to be as large as the CO_2 emissions from the use of fuel to make the lime.

The greenhouse model calculates fertilizer energy use from input data on of the pounds of N, P_2O_5, K_2O, and lime fertilizer applied per fertilized, percent of acreage fertilized, wood yield per acre, and energy required to make fertilizer. In the base case, I assume that 50% of SRIC land is fertilized, at the rate close to that suggested by Turhollow, without lime, and produces 6 dry tons/acre (after harvesting loss). In scenario analyses, I consider more fertilizer (including lime and incidental CO_2 emissions from lime) combined with lower yields, and less fertilizer combined with higher yields. The energy requirements for manufacture of N, K_2O, or P_2O_5 fertilizer are calculated as in the ethanol-from-corn analysis (see Table K.3). N_2O emissions from denitrification of fertilizer are included (see Appendix N on N_2O).

Wood that will be gasified to produce methanol or SNG must at some point be dried, and drying consumes a fair of energy (wood that will be converted to ethanol will not be dried) (Blankenhorn et al., 1985). Wood can be dried at the plantation and shipped dry or it can be shipped green and then dried at the fuel conversion facility. An advantage to drying at the fuel-conversion facility is that there will probably be enough waste heat to dry the wood (see notes to Table K.11). Therefor, I assume that wood that needs to be dried will be dried at the wood-conversion plant at no extra energy cost.

Irrigation increases energy requirements (and cost) considerably, but according to the Oak Ridge studies (Blankenhorn et al., 1985), it increases yield only slightly or not at all. It appears that SRIC will be done without irrigation in many, if not most, cases. I assume no irrigation in all scenarios.

As the data in Table K.9 show, relatively little energy — about 1% of the energy in the harvested wood — is embodied in the equipment used in silviculture. Because I do not count the energy embodied in the equipment used in the other alternative-fuel cycles (except in corn to ethanol), and because this embodied energy is so small, I ignore it here.

In summary, I assume that half the SRIC acreage is fertilized and half is not, that none of the acreage irrigated, and that drying is done at the conversion site at no extra energy cost. I assume that all the "other" fuel (about 0.035 Btu/Btu-wood, for planting, harvesting, chipping) is diesel fuel used by trucks, harvesters, chippers, tractors, and so on. Below, I account the energy required to transport wood to the conversion site.

K.3.2 Energy Required to Transport the Feedstock from the Plantation to the Wood-to-Ethanol or Methanol Conversion Facility

Because it is considerably more costly to transport wood than to transport methanol or ethanol (the wood is much bulkier, much less energy dense than alcohol) wood-to-fuel plants will be located in the middle of large wood plantations, to minimize the average haul of wood to the plant. The wood will obviously be hauled to the plant by truck; no other mode is flexible enough to cover all the ground in a wood plantation. Consequently, the total energy required to move one ton of wood feedstock to the wood conversion facility will simply be the average length of haul multiplied by 2,216 Btu/ton-mi, which is the energy intensity of transporting wood by truck (Table E.2). Diesel fuel will supply the energy.

The average truck haul will depend on the effective radius of the wooded area. This, in turn, depends on trade-offs among wood shipping costs, plant-amortization costs, and product shipping costs: as the wooded area serving a plant increases, feedstock shipping costs increase; however, as the plant gets bigger and reaps economies of scale, lower-cost product transport modes, such as railroads and even pipelines, become available. According to Sperling (1988), the lowest-cost outcome, considering plant amortization and wood shipping cost, is a plant with a capacity of less than 200×10^6 gal/yr. Assuming 150×10^6 gal/yr actual production, 56% wood-to-methanol conversion efficiency, 8,350 Btu/lb wood, 6 net tons wood/acre/yr (after harvesting loss), and 50% of the total land area around a plant is actually growing wood (the rest being given over to roads, facilities, and otherwise unusable or unused land), an area of 344,000 acres, or 538 mi^2 (radius of 13 mi), would be required to support the plant. The average haul would be around 9 mi, one way. At 2,216 Btu/ton-mi, 8,350 Btu/lb, and an 18-mi round trip, the final result is 0.002 Btu-diesel/Btu-wood.

However, some analysts feel that plants larger than 150×10^6 gal/yr would be more economical. Some researchers at SERI believe that wood-to-ethanol plants would draw from an area with a 50-mi radius, which would support an alcohol plant on the order of 2×10^9 gal/yr. Similarly, Smith and Corcoran (1981) in their analysis of wood-to-fuel energetics, assumed that wood would be transported 50 mi one way from the field to the plant (see result in Table K.9). Blankenhorn et al. (1985) calculated roughly the same energy requirements for wood transport as Smith and Corcoran did, implying similar assumptions.

If one assumes an average round trip of 70 mi (corresponding to a feeding area of radius 50 mi), the result is 0.009 Btu-diesel fuel/Btu-wood, consistent with the results of Table K.9. I round this up to 0.01 to account for circuities and the occasional use of other modes.

K.3.3 Energy Used in Conversion Processes

Net greenhouse gas emissions from conversion of wood to fuels are equal to emissions from electricity generation plus emissions of non-CO_2 greenhouse gases from wood gasification and combustion (less a CO_2 credit). Thus, it is important to estimate the electricity requirement in a fairly precise way, because electricity use can be responsible for a large fraction of total greenhouse-gas emissions from biofuels cycles. The amount of wood required per unit of fuel produced is important as well, not because of emissions from wood combustion or gasification (which are for the most part not counted), but because the more wood required, the greater the emissions from silviculture. Some processes, especially methanol-production processes, may require a considerable amount of wood for process heat and feedstock.

Table K.11 shows several estimates of the amount of wood and power required to produce one energy unit of methanol, SNG, ethanol, or gasoline. The estimates of the efficiency of wood gasification are in close agreement, probably because wood-to-SNG is the most developed of the wood-to-fuel routes considered here. I use the more recent estimates of Table K.11.

Estimates of the efficiency of conversion to methanol don't agree as well, probably because the processes are less well-developed. Methanol production from wood will require more energy than gasification, because of the energy losses and power requirements of the synthesis stage. I use values towards the lower end of the range of Table K.11.

Estimates of the efficiency of producing ethanol are quite scattered because the process is not well-developed, and several approaches are being considered. Wood and electricity consumption depend greatly on whether or not the xylose is fermented, and what is done with the lignin. The most recent research indicates that xylose can be fermented economically, but that lignin should be used to provide fuel and electricity for the plant and electricity for export. Wyman and Hinman (1990) assume that 90% of the carbohydrates are converted to ethanol, and that the lignin is burned to provide heat to run the rest of the process. Researchers now expect that steam produced from the combustion of the lignin can generate more than enough electricity to run the plant and provide all process heat (Table K.11). Assuming that the electricity can be sold, the wood-to-ethanol process should be assigned a negative electricity consumption. In this analysis, I assume a wood-to-ethanol process that converts cellulose and xylose, burns the lignin, and exports electricity.

Some processes use oxygen, and this can complicate the greenhouse analysis. If the gasifier is oxygen-blown rather than air-blown, the energy used to separate the oxygen from the air must be counted since it is not entirely trivial. If all the electrical and process heat energy is provided on site by wood feed, then the oxygen is accounted for. If the oxygen is made using purchased electricity, and the electricity consumption of the facility is known, the problem is again taken care of. However, if the oxygen is imported or made on-site by using purchased power with no accounting of power consumption, the energy used to generate oxygen must be estimated. I have assumed that oxygen use, if any (and if not explicitly quantified), is accounted for in the energy-use values in Table K.11.

K.3.4 Emissions of CH_4, CO, NMHCs, and N_2O

Wood gasification and combustion produce CH_4, CO, NMHCs, NO_x, and probably N_2O. EPA's AP-42 provides emission factors for wood-waste boilers, but these probably apply only to lignin combustion in an ethanol plant. Dahlberg et al. (1988) indicate that methane emissions from the combustion of wood chips are almost 100 times higher than methane emissions from combustion of fossil fuels, and CO emissions are about 10 times higher.

Obviously, one has to make do with poor data. For wood to ethanol, I assume that all emissions come from the burning of lignin to provide process heat, and I apply AP-42 factors for CO, NMHC, NO_x, and CH_4 emissions from the combustion of wood in boilers. (Data on the HHV of lignin and the amount of lignin in process fuel are reported in the notes to Table K.11.) For wood gasification (to produce SNG or methanol), I begin with an estimate of NO_x emissions from wood gasification (Table A.2). Then I estimate CH_4, NMHC, and CO emissions by multiplying this NO_x emission factor for gasification by the ratio of CH_4, NMHC, or CO to NO_x

emissions from wood boilers. This assumes that the ratios of emissions from wood gasification are the same as for wood boilers.

To calculate the net effect of CH_4, I deduct the amount of CO_2 that provides the carbon released in the CH_4 (the carbon in the CH_4 emissions was originally in the atmosphere as CO_2).

K.3.5 By-Products

None of the studies reviewed here report any substantial energy by-products from wood cultivation and conversion. In gasification, and gasification and synthesis, most of the energy in the biomass ends up in the fuel product or in the gas or char that is burned to provide process heat. In wood-to-ethanol processes, the cellulose (50% of the wood) is converted to ethanol, the xylose (25% of the wood) probably will be, and the lignin (25% of the wood) can be burned as a fuel to generate more than enough power to run the process or can perhaps be converted to fuel. Wyman and Hinman (1990) imply that in a large ethanol-from-wood program, the wood will be converted to fuel or used as fuel. Therefore, I assume no major nonfuel by-products from any wood-to-fuel process. (Ferchak and Pye, 1981, note that process residues can be returned to the soil as fertilizer; I assume that this has a negligible effect, if any, on fertilizer requirements.)

K.3.6 Energy in Labor

In principle, one should consider the incremental energy requirements of people involved in the biofuel cycle, where "incremental" is relative to the amount of energy the laborers would require were there no biofuels program. It is possible, of course, that the incremental energy requirement so defined would be negative. In any event, incremental labor energy is utterly trivial, whatever its sign. Blankenhorn et al. (1985) estimate that the energy required by moderately active people in SRIC operations, less the energy required by slightly active people, would be 0.002% of the energy in the fuel product (but again, there is no reason to believe that the laborers would be less active if they were not employed in SRIC operations). Even the total energy requirements of laborers, not just incremental energy, would be small, on the order of 0.02% of the energy in the product (Ferchak and Pye, 1981). Giampietro and Pimentel (1990) show 0.03% for corn to ethanol. Labor can be completely ignored.

K.3.7 Distribution of Wood-Derived Fuels from the Plant to End User

To calculate greenhouse gas emissions from the distribution of ethanol or methanol from wood, the greenhouse gas emissions model requires input assumptions about the amount and distance of fuel movement by pipeline, truck, train, international tanker, and domestic tanker. These input assumptions, shown in Table E.1, are scaled to an arbitrarily chosen 100×10^6-ton/yr level of ethanol or methanol production. The calculation is explained in detail in the section "Methanol Transport," at the end of Appendix J (as explained there, the level of production does not matter, as everything in effect is scaled by the level of production). The absolute tonnages are not by themselves meaningful; they are meaningful only relative to the arbitrarily chosen level of total production (again, see the discussion in Appendix J). Here, I briefly explain my assumptions regarding the total production shipped by each mode.

The structure of a wood-fuel distribution system will depend on the optimum size and best location of wood-to-fuel plants, in a large-scale wood-to-fuels program. As discussed above, Sperling (1988) argues that alcohol plants will be relatively small, and will ship their product primarily by truck and rail. However, the 2×10^9 gal/yr plants envisioned by others would be large enough to use pipelines economically, if a large market were available, and especially if several plants shared a pipeline. Even so, pipelines would not be built until a large alcohol-fuel market were well-developed, because pipelines are a large and risky investment. I assume that in 2000 most wood fuels will be shipped by rail to bulk terminals, and from there transported by truck to end users.

My assumptions are the same for ethanol and methanol. Of course, ethanol distribution turns out to require less energy because ethanol contains more energy per gram than does methanol.

I assume that SNG will be delivered from production plants to end users via pipeline. I assume that SNG pipelines will be smaller than NG pipelines because SNG facilities will be smaller and more decentralized than NG production areas. More energy is required to move a gas through a smaller-diameter pipeline, all else equal, and so I assume a higher transmission energy requirement for SNG (Table 3). The new SNG pipelines probably will rely more on combined-cycle turbines than do NG pipelines at present, because combined-cycle turbines are more efficient and have lower fuel costs, and SNG will be expensive (Table 5).

Note on SNG energy density: The SNG estimates in Table K.11 are for medium-Btu syngas, which consists of large amounts of CO, H_2, and CO_2, and typically has a higher heating value in the range of 300-600 Btu/SCF — much less than that of NG. If medium-Btu syngas is used as such in vehicles, then the density of the SNG will be much less than that of natural gas, and the range of the SNG vehicle will be much less than that of the NGV. The SNG can be cleaned up to have a higher energy density, but clean up requires additional energy, which I have not accounted for here. These points should be kept in mind when considering the results of the SNG analysis.

Biomass also can be converted into petroleum-like liquids. Presently, the production of gasoline from wood is less efficient than the production of methanol, but researchers expect to improve this considerably (Gaines et al., 1987; Stevens, 1987, 1989). Estimates are shown in Table K.11.

K.4 Note on Use of Biofuels as Process Fuels

In a large biofuel program, it is possible that biofuels themselves will be used to harvest, deliver, and distribute feedstocks and fuels. For example, methanol-burning trucks may deliver wood-methanol to end users, and ethanol-burning harvesters may harvest wood to be converted to ethanol. This "own-use" of fuel changes total greenhouse gas emissions both directly, as a consequence of burning the biofuel rather than (typically) diesel fuel, and indirectly, because of the need to make the additional fuel used by the trucks and harvesters themselves.

The greenhouse model allows the user to specify that some or all of the energy used to harvest and transport biofuel feedstocks (corn or wood) and to distribute biofuels by truck be the biofuel itself rather than diesel. Both the direct emissions effect and the indirect "own-use" effect are accounted for. In the base case, I have assumed that no biofuels are used at any stage of the process. I have checked the importance of this assumption in sensitivity analyses and reported the cases in which changing this assumption noticeably affects the results (see scenario analyses in Table 12).

K.5 Land Use and the Estimation of the Greenhouse Effect of Biofuels

It is usually assumed that because the CO_2 released from the burning of a biofuel is equal to the CO_2 removed from the atmosphere by the biofuel-feedstock, a biofuel program will be in carbon balance, with no net emissions of greenhouse gases (emissions from the use of process energy and fertilizers aside). In this section, I will show that generally this will not be true.

There are two ways in which a biofuel program can, on balance, emit or uptake greenhouse gases (emissions due to energy use and process fuels aside). One has to do with the transformation of CO_2 to a more potent greenhouse gas, the other with land use:

1. If carbon is removed from the atmosphere as CO_2 but returned as CH_4, CO, or NMHCs (out of the tailpipe), there will be an increase in radiative forcing because CH_4, CO, and NMHCs are more potent than CO_2; this has the same effect as a net increase in emissions of CO_2.

2. The adoption of a biofuel program represents a change in land use, compared to no biofuel program. This change (e.g., the removal of the original vegetation) can result in net emissions of greenhouse gases. More precisely, the time-integrated carbon content of the biofuel ecosystem will probably be different than the time-integrated carbon content that would have resulted had the original ecosystem been left alone, and this will difference constitute a net change in carbon emissions to the atmosphere. This carbon content can be broken down into a soil component and a biomass component.

The first consideration, the transformation of CO_2 to more potent organic species, can be modeled relatively easily, and is done so here. The second consideration has many facets, and is more difficult to quantify. In this section, I will discuss the major aspects of point 2 and estimate the general magnitude of the effects. We will see that emissions from changes in land use can be surprisingly large and can either add considerably to greenhouse gas emissions from a fuel production-and-use cycle, or offset many years of fuel-cycle emissions.

K.5.1 Change in the Carbon Content of Soils and Biomass Over Time

Consider Figure K.1, which illustrates a result of clearing a forest to plant crops. Assume that had the forest remained, it would have been in carbon equilibrium; that is, that it was neither net growing nor decaying, on balance (ignoring seasonal variations in carbon density), before it was cleared. This counterfactual, shown by the solid horizontal line, is the baseline against which changes in carbon density are measured. Note that this baseline need not be equilibrium; if the cleared forest were young and still growing, it would have been a net sequesterer of carbon over time, and the baseline would have a positive slope.

If we cut down the forest and plant crops, two things happen. First, much of the carbon in the original forest ecosystem will be released, over time. This drop, shown by the short-dash line, can be broken down into a biomass-loss component (vertically hatched area) and a soil-loss component (horizontally hatched areas). Second, the carbon content of the new crop system will increase relatively rapidly from zero (it did not exist before) to its equilibrium value as the crops grow. The carbon-content history of the crop system is shown by the long-dash line.

Most of the carbon in the forest biomass and much of the carbon in the forest soil will oxidize. The rate of oxidation will depend on the amount of forest biomass that is burned (oxidation is immediate), the amount that is left to rot (oxidation within 10-100 yr, depending on climate, soil, wood type, and other factors), the amount converted to paper (oxidation within 10 yr) and the amount converted to wood products (oxidation within 100 years) (Detwiler and Hall, 1988; Houghton et al., 1983). A small amount of carbon may be removed permanently from the global carbon cycle as charcoal (Detwiler and Hall, 1988; Bolin, 1986; Campbell, 1986; Woodwell et al., 1983). The soil will lose carbon quite rapidly, within five years.

When the farming stops, and the forest either is replanted or left to recover on its own, the carbon content of the biomass and soil will start to increase and, over many decades, will approach its original equilibrium value. Thus, the total carbon-history of the forest will be a bowl, usually steeper on the "oxidation" side than on the "regrowth" side. (Note that for purposes of illustration, I consider that a certain amount of carbon in the soil belongs to the forest system, even after the forest biomass has been removed, and that the crop system is overlayed on the forest system.)

The carbon history of the crop system will be the inverse of the history of the displaced forest system. After the initial rapid growth of the first planting, the carbon content will reach and

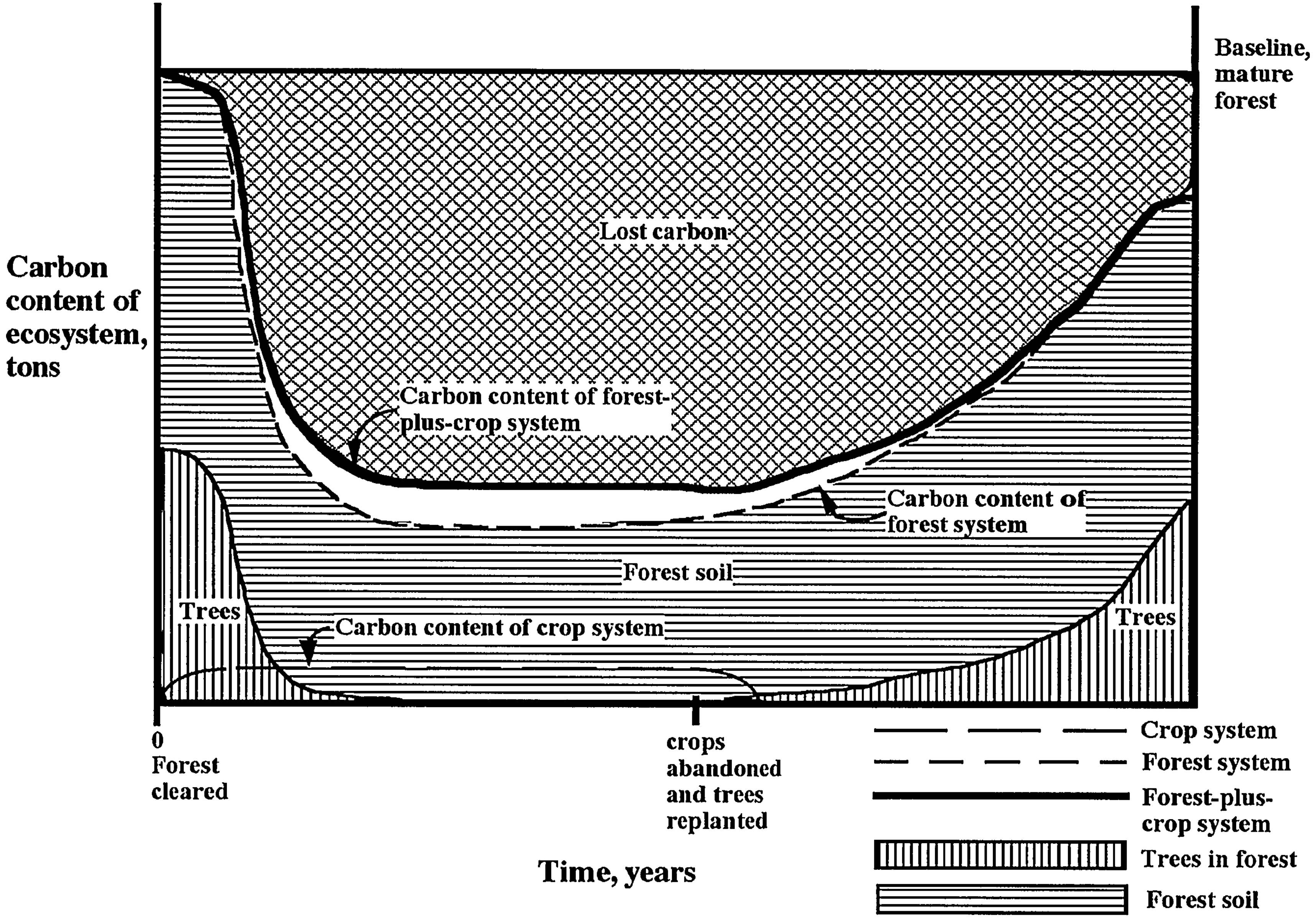

FIGURE K.1 Carbon History of Replacing Forest with Crops remain at its equilibrium value. This is because after the first planting, the rate of oxidation of the carbon (i.e., the rate of burning the fuel made from the plant) will about equal the rate of carbon uptake by new plantings (ignoring the probably minor effect of changes in stocks of biofuels). This equilibrium will continue until the last batch of fuel is burned; for this batch, there will be no counterbalancing uptake by plants, because the program will be over; thus, the total carbon content will go to zero. One might take the perspective that the CO_2 in the first crop is in effect not released until the last crop is burned.

The grand-total carbon history of the forest-to-crop system is simply the sum of the separate crop and forest histories. This is shown by the thick line in Figure K.1. The difference between this history and the baseline, "would-have-been" history of the original forest is the effect on carbon content of switching to biofuel crops (cross-hatched area). On the basis of the assumption that all carbon lost from biomass and soils enters the atmosphere, the loss of carbon is equal to the emission to the atmosphere. Hence, the cross-hatched area shows CO_2 emissions to the atmosphere over time as a result of switching from forest to crop.

The case illustrated in Figure K.1 is only an example; the results will be quite different if, instead, range land is cleared for SRIC plantations. In general, the net CO_2 change (the double line of Figure K.1) can be either positive or negative; the outcome will depend on the difference between the carbon content of the soil and biomass of the original ecosystem and the carbon content of the soil and biomass of the biofuel system, and on the rate of CO_2 uptake and release. Also, Figure K.1 shows the results only for a particular site. In a biofuel program, many sites will be developed over time, so that the total CO_2 curve will rise and fall much more gradually.

With respect to global warming, the important features of the net change in carbon are the total amount and rate of carbon uptake or release. More CO_2 emission is worse than less, because the equilibrium means global temperature increases with CO_2 concentration, and a faster rate is worse than a slower rate because ecosystems have difficulty adapting to rapid change. In the following sections, I will review the biomass and soil carbon content of various ecosystems, and consider the issue of rate of CO_2 release.

K.5.2 Changes in the Carbon Content of Biomass

Table K.12 shows estimates of the carbon content of biomass in crops, grasslands, crops, open woodlands, SRIC plantations, and dense forests. Biomass is about half carbon, so the more biomass per acre, the more carbon per acre in the biomass. Note that forests contain at least an order of magnitude more carbon than do grasses and crops.

The longer the time between the initial clearing and the eventual recovery (if any) of the original ecosystem, and the longer recovery takes, the more the emissions from the initial clearing will affect climate. In some situations, the initial carbon release will be considerably more important than the eventual carbon uptake during recovery. For example, burning a forest will release a large amount of carbon very quickly; much of this carbon in effect will remain in the atmosphere for decades, until the delayed and slow process of regrowth removes it. (Obviously, regrowth will not fix the physically same carbon that was oxidized as a result of clearing. From the standpoint of carbon accounting, though, all CO_2 is the same.)

Similarly, if there is a considerable time between the beginning and end of a biofuels program, then the build-up of carbon in the first planting of the biofuel feedstock (crop or tree) will not be negated by the final release, in the last burning, for many decades. Thus, replacing crops with SRIC trees will result in a large initial sequestering of carbon.

K.5.3 Changes in the Carbon Content of Soil

The carbon content of the soil is a function of local precipitation, temperature, ground cover, plant fall, biological activity, soil type, and other factors. Generally, soils in natural forests contain more carbon per acre than do shrubland and grassland soils, which in turn contain more carbon than crop soils (Burke et al., 1989; Schlesinger, 1977; Table K.12). The conversion of forest soils to permanent agriculture increases the oxidation of the organic matter in the soil, and over the course of few years decreases its carbon content by about 40-50% (Detwiler and Hall, 1988; Woodwell, et al. 1983; Houghton et al., 1983). Even the conversion of range land to crop land can reduce the carbon content of the soil by 20-40% (Burke et al., 1989) in a relatively brief period. If farming stops and the forest recovers, soil carbon will return to near its original level, but as long as the land is cultivated, the soil will contain 40-50% less carbon per acre than before.

Although crop soils generally have less organic matter than do other soils, careful soil management, intended to improve crop yield and reduce erosion will build organic matter in the soil and thereby increase its carbon content (Wallace et al., 1990; Homberg, 1988). Homberg (1988) claims that with proper corn farming, the total carbon in an acre of soil can be built up about 1% per year, enough to remove 0.73 t of CO_2 from the air, per year. Wallace et al., (1990) imply that 0.26 t of CO_2 could be removed, per acre, per year. Havlin et al., (1990) have shown that by adding crop residues to the surface and tilling less often the organic matter in the soil can be built up at about 1-2% per year.

However, such a high net build-up can not be sustained forever. At some point the rate of oxidation of organic matter will equal the rate of addition, and the system will be in dynamic equilibrium. Assuming that the soil reaches steady state (in which carbon added equals carbon oxidized and released) after 10 yr of build-up, a total of 7.3 metric tons of CO_2 will be sequestered in each acre of crop soil. As shown in Table K.12, this amount, while not trivial, is an order of magnitude smaller than the CO_2 lost from the soil as a result of clearing a forest. It will offset a couple years of greenhouse gas emissions from the corn-to-ethanol production and use cycle.

Changes in soil use can cause interesting second-order emissions of greenhouse gases. For example, phosphorus fertilizer that runs off crop land and reaches aquatic systems can cause eutrophication and create anoxic regions where organic matter is not oxidized (Bolin, 1986).

Thus, fertilizer use indirectly can increase carbon sequestering in some water bodies — a point which favors conversion to crop land. On the other hand, Bowden and Bormann (1986) report that N_2O emissions from cleared tropical soils are two orders of magnitude higher than from undisturbed soils. However, as shown in Table K.12, the N_2O release from the soil is insignificant compared to the CO_2 release. The fertilizer effect probably is small as well.

K.5.4 Summary

A biofuel program likely will change the carbon-storage history of the land. On one side of the ledger, most or all of the preexisting biomass cleared to make way for the first planting of the biofuel crop will oxidize to CO_2 at a rate dependent on the type and fate of the biomass. On the other, the new biofuel feedstock crop will sequester CO_2. The soil can either gain or lose carbon, depending on the carbon content of the soil of the new and old ecosystems.

The emissions or uptakes resulting from land-use changes can greatly exceed emissions from the entire fuel production and use cycle. For example, in round numbers, the clearing of a dense forest to plant crops will release about 200 metric tons (t) of CO_2 per acre (soil release plus biomass release; Table K.12). By comparison, the entire corn-to-ethanol production-and-use cycle, including vehicle manufacture, emits about 3.5 t of CO_2-equivalent gases/acre/yr (assuming, in round numbers, 100 bu/acre/yr, 2.6 gal/bu, 23 mi/gal of ethanol, and 590 g/mi CO_2-equivalent emissions from the entire cycle, including vehicle manufacture). Thus, this land use change will emit, in a relatively short period of time, as much as will more than 50 years of ethanol production and use. Even clearing an open woodland with half the carbon density of a dense forest will release as much CO_2 as will more than 25 yr of ethanol production and use. This release will be only partially mitigated if and when the forest recovers after cultivation stops.

Of course, farmers in the United States will not clear forests to plant corn for ethanol. Moreover, there probably is not a large overlap between land suitable for energy forests, and land suitable for energy crops (Energy Resources Limited, 1990). The point here is that even seemingly minor changes in land use — like converting range land to agriculture, which is not so unlikely in the United States — may result in nontrivial emissions of greenhouse gases, compared to emissions from the [rest of the] fuel production-and-use cycle. This conclusion is supported by an analysis by Environmental Resources Limited (1990), which shows that clearing set-aside (grass) land to grow energy crops releases to 19-38% as much CO_2 (per liter of ethanol) as the production of the ethanol (including by-product credits for ethanol production).

Conversely, a considerable amount of CO_2 can be sequestered in SRIC plantations — enough to balance many years of emissions from the production and use of the wood fuel. Converting crop land to SRIC plantations will sequester (net) about 50 t of CO_2 per acre in the biomass (Table K.12). (I assume, perhaps conservatively, that the carbon content of the soils in SRIC systems will be about the same as the carbon content of soils in crop systems; see note i, Table K.12.) By comparison, the entire alcohol production and use cycle will emit about 1.6 t of CO_2-equivalent emissions/acre/yr (assuming 6 dry tons/acre/yr, 8,500 Btu/lb-wood, 43%

conversion efficiency to ethanol, 84,600 Btu/gal of ethanol, 23 mi/gal of ethanol, and 140 g/mi CO_2-equivalent emissions from the entire cycle, including vehicle manufacture). Thus, the uptake of carbon as a result of the land use change will offset about 30 years of emissions of greenhouse gases, including emissions from vehicle manufacture. And in the case of SRIC, the land may well be managed as a forest when the program is over, rather than converted back to cropland, so that there will be no later emissions of CO_2 (from the clearing of the forest) to consider. And since SRIC likely will be directed to abandoned or marginal range and crop land, it is reasonable to conclude that an SRIC program in the United States will provide a one-time CO_2 uptake, and that the whole planting and fuel use program will generate no net greenhouse gases for many decades. Note, too, that the CO_2 uptake offsets all greenhouse gas emissions from the alternative-fuel production-and-use cycle: NO_x, N_2O, CH_4, CO, and NMHCs from all processes.

K.6 Biofuels from Waste

SNG, methanol and ethanol can be made from urban and agricultural wastes, as well as from trees. In many instances, waste will be an attractive feedstock, because it is essentially free.

From a greenhouse perspective, there are at least two opposing considerations in the analysis of making fuels from urban or agricultural wastes. The first, which favors turning wastes into fuels, is that some (of the carbon in) biowaste will decompose to methane if it is not converted to a fuel, whereas, if it is converted to a fuel, it will be oxidized to CO_2, which is less potent. The second, which favors leaving the waste alone, is that some waste oxidizes so slowly as to have only a minor effect on climate, whereas biofuels made from waste will be burned rapidly and so contribute to more rapid climate change.

This implies that, to calculate net greenhouse gas emissions from the use of biomass waste as fuel, relative to the base case of leaving the biomass as waste, one should:

- Ignore the fraction of total carbon that would have oxidized quickly anyway, had the waste been left as waste, because the result — a high rate of CO_2 emissions — is the same in either case (use as a fuel, or leave as waste).

- Ignore the fraction of total carbon that ends up as methane in either case (the burning of a biofuel will produce a small amount of methane).

- Assign, to each mole of biofuel carbon that would have taken longer to oxidize had the biomass not been converted to fuel, a weight ranging from 0 to 1.0, where 0.0 indicates that the slower rate of oxidation (from waste) is treated the same as the faster rate (from fuel combustion), and 1.0 that the slower-oxidizing carbon in waste is treated as though it never oxidizes. The sum of these weighted moles is the total (time-weighted) CO_2 emission due to rapidly burning waste as fuel rather than leaving it as waste to oxidize more slowly.

- Deduct at least 4 moles of CO_2 for each mole of fuel carbon that would have been released in CH_4 had the biomass waste been left to decay. This follows from the fact that 1 mole of CH_4 has a warming effect equivalent to at least 5 moles of CO_2 (see Appendix O), which means that emitting 1 mole of CO_2 instead of 1 mole of CH_4 — equivalent to 5 moles of CO_2 — results in a net removal (relative to the waste/CH_4 base case) of at least 4 moles of CO_2.

Unfortunately, the data do not permit a definitive estimate of these processes. I note, however, that humans generate a huge volume of waste, most of it buried in landfills or disposed at sea, where oxidation may be relatively slow. Olson (1982) notes that poorly aerated landfills remove carbon from the global cycle, and others have calculated that every year at least 0.38 Gt of carbon in human waste alone are "subtracted from any substantial oxidation" (*Nature,* 1986). Also, as noted above, pollution, such as from the disposal of nutrients containing waste, creates conditions that increase permanent carbon deposition. It is quite possible, then, that converting a biowaste to a biofuel will result in the rapid release of a substantial amount of carbon that would have been released slowly, or never, and that this effect will outweigh the benefit of reducing methane emissions. This should be analyzed before major greenhouse benefits are claimed for biofuels from waste.

TABLE K.1 Corn Production Data

Year	1,000 Bushels Corn	1,000 acres Harvested for Grain	Bushels/ Harvested Acre	July Rain (in.)	August Temp. (°F)	Fertilizer Used (lb/acre)[a]				Bushels per lb Fertilizer
						Total	Nitrogen	P_2O_5	K_2O	
1969	4,687,057	54,574	85.88	2.30	73.30	213	102	56	55	0.40
1970	4,152,243	57,358	72.39	3.32	73.60	230	105	64	61	55 6
1971	5,646,260	64,123	88.05	4.43	71.60	208	101	55	52	0.42
1972	5,579,832	57,513	97.02	4.38	72.90	229	110	59	59	0.42
1973	5,670,712	62,143	91.25	4.85	74.30	218	106	55	57	0.42
1974	4,701,402	65,405	71.88	1.78	71.30	211	97	54	61	0.34
1975	5,840,757	67,625	86.37	2.24	75.00	204	99	50	55	0.42
1976	6,289,169	71,506	87.95	3.01	71.20	249	123	60	66	0.35
1977	6,505,041	71,614	90.83	3.68	71.60	250	123	60	67	0.36
1978	7,267,927	71,930	101.04	4.86	72.90	244	120	59	65	0.41
1979	7,928,139	72,400	109.50	5.42	72.30	260	130	61	69	0.42
1980	6,639,396	72,961	91.00	3.14	76.40	252	125	57	70	0.36
1981	8,118,650	74,524	108.94	5.65	71.60	265	133	60	72	0.41
1982	8,235,101	72,719	113.25	4.81	71.00	260	131	57	72	0.43
1983	4,174,251	51,479	81.09	2.35	78.70	258	132	56	71	0.31
1984	7,672,130	71,915	106.68	3.38	74.50	257	134	52	71	0.41
1985	8,875,453	75,209	118.01	3.14	70.30	254	136	52	66	0.47
1986	8,225,764	68,907	119.37	5.18	69.30	237	125	51	61	0.50
1987	7,131,300	59,505	119.84	4.82	73.20	241	127	51	64	0.50
1988	4,928,681	58,250	84.61	3.07	77.10	254	133	55	66	0.33
1989	7,527,152	64,781	116.19							
Summaries										
1969-73			87.03	3.86	73.14	220	105	58	57	0.40
1974-78			87.92	3.11	72.40	232	112	57	63	0.38
1979-83			102.00	4.27	74.00	259	130	59	71	0.39
1984-88			110.35	3.92	72.88	249	131	52	66	0.44
1969-88			97.05	3.79	73.11	240	120	56	64	0.40

[a] Total pounds of fertilizer used divided by all planted acreage, not just fertilized acreage. This method thus properly accounts for nonfertilized acreage.

Sources: Three USDA publications: *Weather in U. S. Agriculture, Fertilizer Use and Price Statistics,* and *Feed Situation and Outlook.*

TABLE K.2 Results of Multiple Regression to Explain Bushels/Acre Corn Production

	Fertilizer			Rain		Temperature	
Independent variables[a]	R_2	Coeff.	t[b]	Coeff.	t	Coeff.	t
Rain, Temp., Fert.[c]	0.643	0.294	3.67	5.43	2.54	-1.92	-1.78
Rain, Temp., Fert.[d]	0.382	0.288	2.79	1.60	1.31	-1.11	-0.45
Rain, Fert.[e]	0.576	0.267	3.20	7.10	3.48		
Fertilizer	0.291	0.292	2.79				

[a] In general, squaring the rain, temperature, and fertilizer dependent variables, singly or in combination, did not change any of the results.

I also ran the regression with a "technology improvement" variable, meant to capture the effect on yield of improvements in the technology of planting, growing, and harvesting corn. The variable was set to 1 in the base year (1969 or 1978), and then increased at 1.5% per year. The technology variable was statistically very significant, and it improved the R_2 of the regression. Interestingly, it did not dramatically change the t statistic for the rain and temperature variables, but it did make the fertilizer variable insignificant. However, I have not shown the results with the technology variable because it is rather arbitrary.

[b] Here, a t-statistic above 2.60 is significant at the 0.99 level, and a statistic above 1.75 is significant at the 0.95 level.

[c] Independent variables are July rainfall in inches, August temperature in °F, and total fertilizer application in lb/acre. Dependent variable is bushels of corn per acre. I used August temperature and July rain data because Teigen (1989) found that these were the most important components of weather. I verified this here (see note d).

[d] As in note a, except using rain and temperature data for the months of May through August. This specification is significantly worse, which is consistent with Teigen's (1989) finding.

[e] July rainfall, lb/acre fertilizer.

TABLE K.3 Energy Used to Make Fertilizers, Btu/lb of N, P_2O_5, or K_2O

Energy Source	Nitrogen, N, in NH_3	Nitrogen, N, in NH_4NO_3	Phosphorus, P_2O_5	Potash, K_2O
From Turhollow (1989)				
Natural gas	30,602		1,986	1,677
Electricity	266		1,181	860
1) Total	30,868		3,167	2,537
From TRW (1980)[a]				
Natural gas	19,603	23,803		
Gasoline			52	17
Diesel fuel			766	250
Fuel oil			92	30
Steam		4,646		
Electricity	27	263	1,292	297
2) Total	19,630	28,712	2,202[b]	594
3) Total from ORNL[c]		28,860	4,515	4,515
4) Total from G & P[d]	37,818		4,959	3,735
5) Total from Pimentel[e]	37,551		11,298	4,465
Used here, base case	25,000		3,000	3,000

Notes: I converted from physical units to energy units by using values of Table C.1 and assuming 3,412 Btu/kWh of electricity.

[a] Converted to per lb-nitrogen from per lb-NH_3 or lb-NH_4NO_3. Calculated from data in the text.

[b] Does not include the energy needed to make molten sulfur. That energy may be the difference between Turhollow's and TRW's estimate.

[c] Blankenhorn et al. (1985). Includes energy for mining, production, transportation, storage, and transfer of fertilizer. I assume that their estimate for ammonium nitrate is in units of Btu/lb-N, not Btu/lb-NH_4NO_3, because even they appear to mean "N" when they say "ammonium nitrate." They also show 620 Btu/lb for lime.

[d] Giampietro and Pimentel (1990). I calculated the K_2O figure by multiplying their figure for K alone by 0.8298, the mass percentage of K in K_2O, and the P_2O_5 figure by 0.4366, the mass percentage of P in P_2O_5. They show 566 Btu/lb limestone (presumably lime, which is made from naturally occurring limestone).

[e] Pimentel (1990).

TABLE K.4 Energy Expenditures[a] per Acre of Corn Planted and Prices Paid[b] by Farmers for Fuels

							My Assumptions[d]	
Year	Energy $/ Planted Acre of Corn[a]	Regular Gasoline ($/gal[b])	Unleaded Gasoline ($/gal[b])	Diesel Fuel ($/gal[b])	LPG ($/gal[c])	Power ($/kWh[c])	NG ($/$10^3$ ft^3)	Coal ($/ton)
1980	23.74	1.104	1.139	0.969	0.62	0.047	3.39	28.76
1981	28.82	1.248	1.257	1.143	0.70	0.053	4.00	32.31
1982	24.99	1.214	1.201	1.130	0.66	0.062	4.82	34.90
1983	20.95	1.000	0.997	1.000	0.77	0.065	5.59	35.50
1984	19.45	1.129	1.115	1.058	0.75	0.068	5.55	35.12
1985	22.87	1.140	1.135	1.043	0.72	0.070	5.50	34.53
1986	18.22	0.848	0.837	0.748	0.64	0.069	5.08	33.30
1987	18.80	0.883	0.851	0.769	0.56	0.068	4.78	31.83
1988	16.47	0.858	0.823	0.744	0.58	0.067	4.63	30.60

[a] From USDA, Economic Research Service, *Costs of Production* (various years). My "energy $/planted acre of corn" figure is the sum of the USDA's fuel, lube, and electricity cost per acre and drying cost per acre. The electricity cost in the former includes the cost of electricity used for irrigation. The drying cost per acre, according to the USDA, is all fuel costs (mostly LPG). For every year, I have used the latest, revised figures.

Note that technically, we want to know energy-dollars per acre of corn harvested for grain rather than energy-dollars per planted acre of corn. However, the two are likely to be extremely close, because virtually all planted acreage is harvested for grain.

[b] Calculated by dividing total expenditure on fuel used for farming (Table K.5) by total quantity of fuel purchased for farming, in the corn belt (excludes household use of fuels) (USDA, *Farm Production Expenditures*, various years).

[c] From USDA, *Agricultural Prices.* LPG prices are for July of the year. Price of power from 1985-1988 is my estimate, based on EIA data.

[d] Based on data in EIA *Annual Energy Review 1989* (1990).

TABLE K.5 Thousands of Dollars of Expenditures on Fuels and Electricity by U. S. Farms in the Corn Belt (except as noted)

Year	Regular Gasoline	Unleaded Gasoline	Diesel Fuel[a]	LPG	Power[b]	NG	Other[a] (coal)	Total[c]
1980[d]	2,678,195	791,094	3,328,379	678,782	1,779,492	270,438	13,324	9,919,885
1981[d]	2,795,068	915,530	3,591,805	717,544	2,137,253	291,905	9,829	10,891,753
1982	507,517	115,353	656,114	205,713	334,074	34,666	1,308	1,922,852
1983	443,053	125,089	682,337	140,625	341,221	27,687	4,151	1,846,969
1984	389,882	108,716	614,754	204,856	381,791	14,196	24,772	1,808,524
1985	347,443	91,703	625,617	228,975	373,203	28,908	11,019	1,775,772
1986	252,500	64,302	448,651	159,069	381,341	19,298	4,400	1,394,626
1987	244,673	56,399	478,792	101,317	412,499	21,807	29,512	1,394,965
1988	203,360	58,416	422,925	81,747	415,412	21,045	4,037	1,260,834

Note that these data are expenditures by all farms in the corn belt, whereas what we want is expenditures for corn farming in particular. However, the difference is almost certainly unimportant, first, because corn farming is a major part of all farming in the corn belt, and second, because we are interested in the percent of the total energy expense spent on each fuel, not the absolute expenditures themselves, and there is likely to be much less variation among farms in this number (the ratio) then in the absolute numbers.

[a] For 1980-1983, figures under "diesel fuel" include kerosene and fuel oil, and figures under "other" are the difference between the total shown by the USDA and the sum of all the expenditure categories shown. For 1984-1988, the figures under diesel fuel include only diesel fuel, and the "other" category, which is explicitly shown by the USDA for these years, includes coal, kerosene, wood, and other fuels.

[b] Includes electricity for irrigation.

[c] Includes a small amount of expenditure for "motor oils, grease, and special fluids." This expenditure for oil and fluids must be included in the total expenditure here because it is included in the dollar/acre figures of Table K.4; that is, the "expenditure total" here, which is used to determine each fuel's share of total energy expenditures, must be defined the same way as the "total" in "total energy \$/acre." Note, though, that I do not actually count any emissions from oxidation of grease. This is because I cannot determine how much of the expenditure is for grease, which eventually oxidizes to CO_2, and how much is for non-CO_2-producing "special fluids."

[d] National expenditure data, as opposed to expenditures in the corn belt.

Source: USDA, *Farm Production Expenditures* (various years).

TABLE K.6 Million Btu Per Planted Acre of Corn (except last column)

Year	Regular Gasoline	Unleaded Gasoline	Diesel Fuel	LPG	Power	NG	Other (coal)	Total	10^6 Btu/ Bushel
1980	0.726	0.208	1.140	0.229	0.308	0.197	0.024	2.832	0.0311
1981	0.741	0.241	1.153	0.236	0.361	0.199	0.018	2.949	0.0271
1982	0.679	0.156	1.046	0.354	0.239	0.096	0.011	2.582	0.0228
1983	0.628	0.178	1.073	0.180	0.204	0.058	0.029	2.350	0.0290
1984	0.464	0.131	0.867	0.256	0.205	0.028	0.166	2.117	0.0198
1985	0.491	0.130	1.071	0.357	0.236	0.070	0.090	2.444	0.0207
1986	0.486	0.125	1.087	0.283	0.246	0.051	0.038	2.317	0.0194
1987	0.467	0.112	1.164	0.212	0.281	0.063	0.273	2.572	0.0215
1988	0.387	0.116	1.029	0.160	0.278	0.061	0.038	2.070	0.0245

Data on 10^6 Btu/acre are calculated from data of Tables K.4 and K.5. Data on 10^6 Btu/bushel are calculated by dividing total 10^6 Btu/planted-acre by bushels/acre-harvested for grain (Table K.1).

TABLE K.7 Estimates of Energy Used to Grow Corn and Produce Ethanol, Btu-Process Energy/Btu-Ethanol

					Conversion to Ethanol			
Reference	Fertilizer[a]	Farming	Farm Equipment	Corn Transport	Coal	Electricity[b]	Facility	Notes
Giampietro and Pimentel (1990)	0.33	0.16	0.13	0.06	0.90	I?	0.06	c
Jones (1989)	NE	NE	NE	NE	0.79	0.057	NE	d
Jones (1989)	NE	NE	NE	NE	0.60	0.071	NE	e
Anderson (1988)	-------0.41-0.62-----		NE	?	0.57-0.85	?	NE	f
Ferchak and Pye (1981)	-------0.46-0.53-----		I?	NE	---see Katzen (1979)---			g
Katzen Associates (1979)	---------0.44--------		NE	I	0.49	0.050	<0.01	h
Chambers et al. (1979)	0.41	0.34	0.09	0.11	0.59	I?	0.04	i
Ho (1989)	0.21	0.22	NE	NE	0.59	0.052	NE	j
Parisi (1983)	0.28	0.23	0.10	0.05	0.42	I	0.09	k
Marland and Turhollow (1990)	0.17	0.10	NE	NE	0.33-0.53	0.048	NE	l
Pimentel (1990)	0.27 (0.33)	0.27	0.07	0.006	NE	NE	NE	m
Wayman and Parekh (1990)	NE	NE	NE	NE	0.28-0.77	0.036-0.049	NE	n
Energy Fuels Development (1990)	---------0.29--------		NE	NE	0.38	0.11	NE	o
Keim, IRI (1989)	NE	NE	NE	NE	0.63	0.052	NE	p
This report	0.19	0.10	NE	0.03	0.35-0.60	0.050	NE	q

An "I" under "conversion to ethanol/electricity" means electricity use is included in the estimate of coal-energy requirement; "?" means it is not clear if the electricity-energy is included in the coal-energy or if it has simply not been counted. "?" under "corn transport" means that it is not clear if corn transport energy has been included under farming energy or not. "I" under "corn transport" or "farm equipment" means that the energy is included under "farming" and "fertilizer." "NE" means that the particular kind of energy use is not estimated. Estimates are based on higher heating values, unless stated otherwise.

For methanol, I assume 22.7 kJ/g or 64,500 Btu/gal HHV and 19.95 kJ/g or 56,700 Btu/gal LHV; for ethanol, I assume 84,600 Btu/gal HHV and 75,670 Btu/gal LHV.

[a] Does not include N_2O emissions from denitrification of fertilizer (see Appendix N).

[b] Electricity counted at 3,412 Btu/kWh, unless otherwise noted.

TABLE K.7 (Cont.)

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[c] "Farming" energy includes labor (negligible), fuel, electricity, and energy embodied in herbicides, insecticides, and seeds. "Fertilizer" energy includes energy embodied in lime fertilizer. "Farm equipment" energy includes energy embodied in transport vehicles. Energy required to ship water to the conversion plant is not included.

[d] Based on actual energy and material balance for the South Point Ethanol plant in October 1984. The plant yielded 2.69 gal/bu of corn and 3,212 tons of DDGS/10^6 gal of ethanol. Energy for drying DDGS is included. I count electricity at 3,412 Btu/kWh and coal at 21×10^6 Btu/ton. I ignore energy in limestone, chemicals, and water.

[e] Based on the actual energy and material balance for the Kentucky Agricultural Energy Corporation plant in July, 1987. The plant yielded 2.58 gal of ethanol/bu of corn and produced 2,985.6 tons of DDGS/10^6 gal of ethanol. I count electricity at 3,412 Btu/kWh and coal at 21×10^6 Btu/ton.

[f] Anderson takes his numbers from other sources, including the Katzen report (1979) and an earlier report by Amoco.

[g] Ferchak and Pye (1981) cite a 1976 estimate that "total cultural energy" requirements for corn are 10.2-11.621 × 10^6 Btu/acre-year (I assume HHV); at 100 bu/acre and 2.6 gal of ethanol/bu (my assumption), the result is 0.46-0.53 Btu/Btu ethanol. Their use of "total" implies that the energy embodied in farm machinery is included.

[h] The farming and fertilizer energy requirement is from a 1974 report and includes energy used for field preparation, harvesting, fertilizer, transport, and miscellaneous activities. The Katzen design produces 2.57 gal of ethanol/bu and consumes 9.2 tons/d of ammonia, 1.2 tons/d of yeast, 3.7 tons/d of chemicals for treating wastewater, and 1,500 gal/d of denaturant. It produces 536.7 tons/d of DDGS and 31.6 tons/d of ammonium sulfate. The by-product DDGS is dried with waste heat from the boilers.

I calculated the electricity consumption assuming a 32% generation efficiency.

The ammonia consumption amounts to 0.121 lb/gal of ethanol produced, or 0.02-0.04 Btu-ammonia/Btu-ethanol, depending on one's assumption about the amount of energy required to make ammonia. This is a nontrivial amount of energy. Nevertheless, I do not count it, because I have not evaluated all chemical inputs for all fuels and processes.

The Katzen design is cited by Chambers et al. (1979), White (1980), TRW (1980), Ferchak and Pye (1981), the *DOE Handbook* (1983), and Anderson (1988). The 0.01 figure for facility energy (under "conversion to ethanol") is from the TRW report (1980).

TABLE K.7 (Cont.)

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[i] Data are for a project described by ACR Process Corporation, of which Chambers is (was) president. The ACR process was designed specifically to produce gasohol (that is, gasoline and ethanol together, not just ethanol which later would be blended with gasoline) and have low energy consumption. It produces 2.5 gal/bu. Conversion figures include energy for drying by-products. All figures are supposed to include all nonrenewable energy inputs, which implies that electricity is included.

Two other studies cited by Chambers et al. estimate about 1.9 Btu of process energy and 0.60 Btu of agricultural energy per Btu of ethanol. Chambers et al. claim that the ACR estimate for agricultural energy is more realistic than these other two.

In converting Chamber et al.'s estimates of process energy requirements to percentages of energy in the ethanol product, I have used their estimate of 77,200 Btu/gal of ethanol, on the assumption that they were consistent and always used lower heating values.

Chambers et al. calculate energy embodied in capital equipment by multiplying the capital cost by 100,000 Btu/dollar. Lave (1977) cites an estimate of 77,600 Btu/dollar.

[j] The main difference between Ho and Marland and Turhollow (1990) is that Ho assumes that corn fields yield 90 bu/acre (the 10-year average in the U. S.) and M & T assume a 1987 value of 119. Another difference is that Ho uses all lower heating values, whereas M & T use all higher values. This means that if both Ho and M & T says a process takes 10,000 Btu/gal of ethanol, the energy consumption is 13.2% for Ho, but only 11.% for M & T.

Ho says that conversion plants use 12,000 Btu/gal of ethanol for electricity and direct heat. I assume that all of this is electricity, and that he means Btu-thermal, and convert back to Btu-electric at 10,400 Btu/kWh. Ho's energy consumption data may come from earlier work by Keim (see note p).

[k] The value for "farm equipment" includes energy embodied in transport trucks (the value for corn transport does not) and is based on the estimate of Chambers et al. (1979) and one other reference.

The value for "farming" includes energy used by machinery, irrigation, and "other." Fuel type is not specified. The value for "conversion to ethanol/coal" is equal to the sum of energy for wort preparation, fermentation, alcohol recovery, and "other" (lighting, administration...). It apparently does not include energy for drying by-products, as that is counted in the by-product analysis.

It is not clear how the author derived the value for "conversion to ethanol/facility." In the text, he mentions only the estimate by Chambers et al. (1979), which is quite a bit lower.

[l] Fertilizer energy requirements are about 96% NG and 4% electricity (Btu-electric). Farming energy is 86% liquid fuel for direct use, 11% energy for irrigation and embodied in pesticides, and the rest electricity. I have converted from their 10,400 Btu/kWh to 3,412 Btu/kWh. See also Marland and Turhollow in Segal (1989) for an earlier version of their work. Based on a fairly thorough literature review.

TABLE K.7 (Cont.)

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[m] Pimentel assumes a corn yield of 110 bu/acre. I assume 2.6 gal/bu. Energy ratio under "Fertilizer" includes energy in lime. If the energy values of seeds, insecticides, and herbicides are included here, the ratio increases to 0.33. The energy ratio under "Farming" includes irrigation, drying, electricity, gasoline, and diesel fuel.

[n] The lower coal consumption figure is based on Wayman and Parekh's report of a plant that consumes 21,000 Btu/gal (I assume they are using lower heating values), a value they say "is considered low by industry standards" (p. 199). They correlate this figure with a steam consumption rate of 2.04 kg steam/liter of ethanol (indicating about 1,200 Btu/lb steam). Then, they show that whole grain milling consumes up to 5.64 kg steam/liter of ethanol.

The lower electricity consumption figure is calculated from Wayman and Parekh's figure of 0.24 kWh/liter for whole grain milling; the higher, from their figure of 0.32 kWh for wet milling (I use HHVs).

[o] The values shown for conversion are design values. Actual energy consumption is lower: 0.34 Btu-coal/Btu-ethanol and 0.085 Btu-electricity/Btu-ethanol.

[p] Keim shows 1.3 kWh of purchased power per gallon and 40 lb of steam from coal per gallon. I assume 1,195 Btu/lb steam and 90% generation efficiency, following a personal communication from Ho to Keim.

[q] See text for details. Fertilizer energy estimate from data of Table K.1 and K.3, with additional accounting for energy embodied in herbicides, insecticides, and seeds (factor of 1.2; see text), and energy in lime and sulfur fertilizer. Farming energy estimate from data of Table K.6. Conversion energy estimates are from consideration of data of this table. Although in the base case, I do not account for energy embodied in farming equipment and conversion facilities, in the scenario analyses of the main chapter, I do consider the effect of assuming that 0.15 Btu of energy is embodied in equipment and facilities per Btu of ethanol produced.

TABLE K.8 Estimates of By-Product Credit for DDGS

Reference	DDGS Replace	Total Btu/gal	% Breakdown in Btu/gal G / D / R / C / NG / E
TRW (1980)	Soy protein	8,526[a]	32/28/1/31/7/[a]
Ho (1989)	Soy protein	7,000-7,600[b]	
Marland & Turhollow (1990)	Soy protein	7,390[c]	--/45/--/30/6/20
Chambers et al. (1979)	Corn feed	7,000-20,000[d]	
EPA (1990)[e]	Soybeans	8,777-9,418[f]	
Giampietro and Pimental (1990)	Feed	10,500[g]	

G = gasoline; D = diesel fuel; R = residual fuel; C = coal; NG = natural gas; E = electricity.

[a] 2,695 Btu gasoline, 2,415.5 Btu diesel fuel, 110.6 Btu residual fuel, 577.8 Btu NG, 2,635.7 Btu coal, and 91.5 Btu other energy. I have not assigned the 91.5 Btu to a fuel category. Electricity does not show up here because TRW has already broken down electricity into specific input fuels; in other words, the breakdown shown in this note includes fuel inputs to electricity. TRW assumes 3,544 tons of DDGS/10^6 gal of ethanol, based on the design described by Katzen Associates (1979), which is a bit higher than the actual production of DDGS reported recently by two ethanol plants (Jones 1989); see notes to Table K.7. Wyman and Hinman (1989) report 3,269 tons of DDGS/10^6 gal of ethanol for whole corn milling. This is close to the Katzen number (3,544).

[b] Ho (1989) reports 7,000 Btu/gal using LHV; if he had used HHV, the result would have been about 7,600 Btu/gal. TRW and Turhollow use HHV; Chambers et al. apparently use LHV.

[c] They estimate 0.721 lb of soybean meal per lb of DDGS and count electricity at 10,400 Btu/kWh.

[d] Chambers et al. assign DDGS used as animal feed (not protein feed) a credit of about 27% of the energy required to produce corn, which results in 7,000 to 20,000 × 10^6 Btu/10^6 gal of ethanol, depending on one's assumption regarding the amount of energy required to produce corn (the upper end probably is too high).

[e] *Analysis of the Economic and Environmental Effects of Ethanol as an Automotive Fuel.*

[f] The reference actually shows the soybean farming credit as 1.37-1.47 lb of CO_2/gal of ethanol produced. If the CO_2 credit comes from the use of diesel tractors, at 70,800 g of CO_2/ 10^6 Btu of diesel (Table A.2), the result is 8,777-9,418 Btu of diesel/gal of ethanol. I assume HHV.

[g] The authors may be using LHV. If so, the use of HHV would raise the total to about 11,600 Btu/gal.

TABLE K.9 Energy Required to Grow and Harvest Wood in SRIC Systems, Btu-Process Energy/Btu-Wood

Reference	Tree Type	Btu/lb	Fertilizer	Irrig.	Equipment	Drying	Transport	Other[a]	Total[b]
Blankenhorn et al. (1985)	Poplar	8,319	0.069	0.029	I[c]	NI	I	0.067	0.165[d]
Blankenhorn et al. (1985)	Poplar	8,319	0.070	NI	0.020	NI	0.009	0.037	0.136[e]
Ledig (1981)	Poplar	NS	0.032	0.058	NI	NI	NI	0.005	0.094
Ledig (1981)	Poplar	NS	0.038	0.017	0.007[f]	NI	NI	0.027	0.089
Ranney et al. (1987)	Generic	8,100	?	?	?	I	I	- -	0.083[g]
Ledig (1981)	Jack pine	NS	0.021	0.022	0.009[f]	NI	NI	0.027	0.079
Ledig (1981)	Poplar	NS	0.047	NI?	NI?	NI	NI	0.028	0.074
Smith & Corcoran (1981)[h]	Generic	8,350	0.040	NI	0.003	NI	0.011	0.014	0.068
Blankenhorn et al. (1985)	Poplar	8,319	NI	NI	0.016	NI	0.008	0.035	0.059[e]
Ferchak & Pye (1981)	Generic	8,350	NI[i]	NI	0.006[j]	NI	NI	0.040	0.046[k]
Parisi (1983)	Generic	NS	I	I	I	NI	I	- -	0.019
This report	Generic	8,350	0.039[m]	NI	NI	I[n]	0.008	0.035	0.087

SRIC = short-rotation intensive cultivation; ODT = oven-dried ton of wood. "I" means that the energy for the category is included in the total shown but is not broken out separately; "NI" means the energy item is not counted at all; "?" means not clear if included in the total or not; "NS" means not specified.

[a] Energy used for planting, harvesting, chipping, etc.

[b] Excludes energy used for transport and energy embodied in equipment.

[c] Includes energy embodied in agricultural equipment but not in the wood-to-fuel conversion plant. Blankenhorn et al. (1985) do a detailed calculation of the energy embodied in machinery; it includes energy required to make the materials (mostly steel), energy required to fabricate the machinery, and energy required to maintain and repair the machinery. Their figures for energy in materials agree with mine (Appendix P), but their figures for fabrication energy seem high.

[d] This scenario is not given explicitly in the reference. I have added irrigation energy cost to a fertilizer-only case.

TABLE K.9 (Cont.)

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[e] Table 3-8 of Blankenhorn et al. (1985) shows establishment, maintenance, fertilizer (if any), and harvest and transport energy requirements for an SRIC-to-ethanol scenario. I have broken their estimate for "establishment" into energy embodied in equipment and other energy, and their estimate for "harvest and transport" into energy embodied in equipment, including transport trucks, energy used by transport trucks, and harvest energy. I then add all the energy embodied in equipment and assign it to my "equipment" category. I assign the energy used by transport trucks to my "transport" category; all the remaining energy (nonequipment, nontransport energy used for establishment, harvest, and maintenance) I assign to "other."

I apportion their single number in their Table 3-8 for "harvest and transport" energy into energy embodied in equipment, transport energy, and harvest energy, by using their data from their Table C-8, strategy B: I assign fuel use by tractor truck and trailer van to my "transport" category, all fixed energy to my "equipment" category, and harvest energy to my "other" category. I apportion establishment energy into equipment and other energy by using the data of their Tables A-15 and A-16.

[f] Irrigation equipment.

[g] Presumes drying to 20% moisture (authors may mean "passive" drying; it is not quite clear). The authors note that fertilizing improves growth on some sites, but, in general, less fertilizer is used than in agriculture, and in some cases, no fertilizer is needed. Not clear if energy embodied in capital is included. The authors give a single total energy requirement, not broken down into subareas.

[h] Data in reference are in 10^6 Btu/ODT. I assume 8,350 Btu-lb. Their fertilizer use and energy content assumptions were 1,000 lb of nitrogen/acre/yr and 33,000 Btu-lb for manufacturing and applying fertilizer. They assume energy required to build roads would be small. Data in reference indicate that energy cost would be the same if no fertilizer were used (energy input would be reduced by about half, but yield would be reduced by about half, too).

[i] Manure, but no chemical fertilizer.

[j] Based on a yearly, amortized, embodied energy requirement of 3,979 Btu/lb, a number Ferchak and Pye get from a 1973 report. Since energy consumption has declined considerably since pre-1973, the 3,979 figure is probably too high. To see this, consider the data of Table P.4. Assume that the material in the farm equipment averages 25,000 Btu/lb, and that repair brings the total to 30,000 Btu/lb before amortization. If the equipment lasts 15 years, the result is 2,000 Btu/lb per year, half the figure used by Ferchak and Pye.

[k] Data in original in Btu/ODT. They assume a rather high yield of 10 oven-dried tons/acre/yr, and 1/2 ton residue-fertilizer (such as manure, not chemical fertilizer) per oven-dried ton of wood. I assume 8,350 Btu/lb-wood.

TABLE K.9 (Cont.)

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[l] Given as 0.038 Btu-input/Btu-ethanol. I assume 50% conversion efficiency to ethanol. Parisi does not break his estimated total energy requirement into subareas.

[m] This is the figure for fertilized acreage only. Some acreage is not fertilized. Calculated from data of Table K.10.

[n] Included in the energy used by the conversion facility.

TABLE K.10 Fertilizer Use for and Productivity of SRIC

Reference	Fertilizer (lb/acre/yr)				Yield (dry tons/acre/yr)
	N	P_2O_5	K_2O	Lime	
Turhollow (1989)	44.6	13.4	13.4	0	5.00[a]
Blankenhorn et al. (1985)[d]	151.3	83.4	99.5	2079.6	4.30
Smith & Corcoran (1981)	1,000.0	NS	NS	NS	5.00[c]
Ranney et al. (1987)	------- Zero in some cases ---------				5.85[d]
Ranney et al. (1987)	------- Zero in some cases ---------				7.65-9.00[e]
Klass (1987)	-------- No fertilizer used ---------				4.2-27.3[f]
Base-case assumptions here[g]	150.0	25.0	25.0	0.0	6.0

[a] Yield after harvesting loss of about 20%, indicating about 6.0 tons/acre/yr before losses.

[b] Fertilizer and yield figures are four-year totals for the Basher site, with fertilization and no irrigation, divided by four. Yield is after harvesting loss of 10% has been deducted.

[c] "Growth rate."

[d] 1987 value. Not clear if this accounts for harvesting losses.

[e] Projection for the year 1996, assuming ambitious research. Not clear if this includes harvesting losses.

[f] Not clear if this is after or before harvesting. Range shown is overall range for six different SRIC systems not using fertilizer. High end of range applies to cottonwoods. Excluding cottonwoods, typical yield was 6-7 tons/yr.

[g] Fertilizer applied to acres receiving fertilizer. I assume in the base case that about 50% of the acres receive fertilizer.

TABLE K.11 Energy Required to Convert Wood to Fuel, Btu-in/Btu-Fuel

Process and Reference	Wood	Electricity	Other	Notes
Methanol/wood/gasification				
Chrysostome et al. (1986)	2.05-2.36	NS		a
Mehrling and Reimert (1986)	2.22	NS		b
Klass (1987)	1.75-2.04	NS		
Stone and Webster (1987)	1.74	0.083		c
DOE (1983)	1.75	0.0164		d
White (1980)	1.35	0.019		e
SERI (1989)	NS	0.038		f
Hall et al. (1990)	1.73	0.019	?	g
SNG/wood/gasification				
Feldmann et al. (1988)	1.46	0.024		h
DOE (1983)	1.37	0.000005		i
Flanigan et al. (1988)	1.36	NS	1.44	j
SERI (1989)	NS	0.02		f
Evans et al. (1988)	1.33	0.033		k
Gaines et al. (1987)	~1.33	NS		l
Cogliati (1986)	1.35	I		m
Bridgwater (1990)		0.011		mm
Ethanol/wood/enzymatic hydrolysis				
Stone and Webster (1985)	3.16	0.31		n
Ferchak and Pye (1981)	2.83	0.05-0.24	(-0.90)	o
Blankenhorn et al. (1985)	2.17	NS		p
Wright (1988)	2.00	0.08		q
Lynd (1990)	1.7-2.0	I?		r
Hinman et al. (1989)	?	-0.02		s
Private communications from SERI	2.35	-0.08		t
Wood-to-gasoline				
Stevens (1989)	1.4-2.7	0.01-0.03		u
Gaines et al. (1987)	1.6-3.1	NS		v

NS = not specified; "I" means included in wood requirement.

For methanol, I assume 22.7 kJ/g or 64,500 Btu/gal HHV and 19.95 kJ/g or 56,700 Btu/gal LHV; for ethanol, I assume 84,600 Btu/gal HHV and 75,670 Btu/gal LHV. Electricity is counted at 3,412 Btu/kWh, unless otherwise noted.

[a] This estimate includes neither electric power nor energy required to convert oxygen.

[b] Some of the steam raised from the wood fuel is used to separate air and provide oxygen. However, some electricity is still imported. Wood drying is included in the system.

TABLE K.11 (Cont.)

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[c] The electricity figure is equal to the amount reported as being purchased, 0.30 Btu-electric/Btu-methanol, plus my calculation of the amount of electricity required to produce the required oxygen. I calculated this to be 0.053 Btu-electric/Btu-methanol, based on the reported oxygen consumption of 0.6 kg-O_2/liter methanol and an oxygen-manufacturing power demand of 0.2 kWh/lb-O_2 (Table J.2). It is not clear if wood drying is included, as I have not consulted the original reference.

[d] The *DOE Handbook* (1983) expresses electricity consumption as Btu of electricity/Btu of product. I assume that Btu of electricity refers to end-use power consumption (3,412/Btu/kWh). The DOE estimates do not include energy used to make the equipment used to convert the biomass. They assume 9,650 Btu/lb for the wood feed to the methanol process.

[e] White estimates that the use of purchased electricity produces 13 lb of $CO_2/10^6$ Btu of methanol. He assumes that the electricity plants use coal and have a heat rate of 10,340 Btu/kWh and that coal produces 225 lb of $CO_2/10^6$ Btu. These numbers result in 0.019×10^6 Btu of power (end-use electricity)/10^6 Btu of methanol. He also states that wood combustion or gasification produces 292 lb of CO_2 per 10^6 Btu of methanol. Assuming 50% carbon in the wood, and 8,500 Btu/lb (Klass 1987), the result is 1.35×10^6 Btu of wood/10^6 Btu of methanol.

[f] Stevens (personal communication, 1989) of the Solar Energy Research Institute (SERI) says that the latest information at SERI indicates 0.7-0.75 kWh/gal of methanol, from wood gasification. He estimated that production of medium-Btu SNG from wood would require 25-50% less power, because the methanol synthesis loop, in which the gas is compressed, would be eliminated.

[g] The authors report that electricity for the process costs $0.0290/gal. Assuming $0.08/kWh, the result is 0.3625 kWh/gal, or 0.019 Btu/Btu. The process produces excess steam but also requires some additional fuel (probably on the order of 0.04 Btu-fuel/Btu-methanol). I assume that the energy value of the excess steam is equal to the energy value of the extra fuel required.

The Hall et al. data are from a December 1989 report by Chem Systems, *Assessment of Cost of Production of Methanol from Biomass*, for SERI.

[h] These figures include wood drying: wood is dried in this system by waste heat from the gasifier. The process apparently does not require pure oxygen.

[i] See note d regarding electricity consumption and equipment. The medium-Btu syngas process uses a small amount of natural gas to burn the wood. They assume 8,538 Btu/lb for wood chip feed for SNG.

[j] Typical test results were: 1,557,317 Btu/h feed, 1,140,813 Btu/h gas (apparently HHV), and 78 lb/h propane (21,110 Btu/lb). Process does not require pure oxygen. Authors remark that excess heat probably would be sufficient for drying the wood. The "other" fuel is the propane; a surprisingly large amount is required.

TABLE K.11 (Cont.)

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[k] The data given in the reference are 0.22 lb-O_2/lb feed, 8,306 Btu/lb-feed, and 75% thermal efficiency. I assume 0.2 kWh/lb-O_2, from Table J.2.

[l] The authors state that the long-term goal is to achieve an overall thermal efficiency of 95%, which implies that only 5% of the feed wood energy is required for process energy (unless process energy is provided by other sources). It is not clear if their energy estimates include power or drying.

[m] The author states that the heat in flue gas would be used to dry the wood and generate electricity for the plant. No oxygen (air separation) is required if it is acceptable for the medium-Btu syngas to have some methane; if the methane is to be removed, oxygen must be added, at an additional energy cost. A small amount of auxiliary fuel (propane) is used at startup.

[mm] Bridgwater (1990) cites a 1986 review of gasifiers that states that power costs 0.114 English pounds per gJ produced. In 1986, the industrial sector in the United Kingdom paid 5.3 cents/kWh, and the pound and the dollar traded at the rate of 0.68:1 (EIA, *International Energy Annual 1986*, 1987). This results in 3.163 kWh/gJ.

[n] I calculated the electricity consumption from their electricity cost data, assuming 4 cents/kWh. It is not clear if drying is included or if xylose is assumed to be converted.

[o] Values shown do not include energy embodied in labor, chemicals, or plant and equipment, which add up to an additional 0.032 Btu/Btu-ethanol (assuming the low end of the range of chemical requirements), of which 3/4 is energy embodied in the ethanol plant. They appear to assume 43,000 Btu/lb of material in the ethanol plant. This probably is high by a factor of two: concrete, probably the main material in an ethanol plant, contains much less than 10,000 Btu/lb, and steel, the second-most common material, contains around 20,000-30,000 Btu/lb. Material transport and assembly (plant fabrication) typically require much less energy than material manufacture. Thus, it seems likely that the whole process of making and assembling the materials for a plant averages no more than 20,000 Btu/lb.

The wood requirement is calculated from their assumption of 71 gal of ethanol per oven-dried ton and my assumption of 8,500 Btu/lb of wood. I presume that the energy required to dry the wood is included in the wood or electricity requirements, since Ferchak and Pye state that drying and electricity are taken to be "subsidiary to an on-site processing plant" (p. 19).

One process cited by Ferchak and Pye required 3 lb of chemicals/gal, which, at 20,000 Btu/lb, would require 71% of the energy in the output ethanol. This seems quite high, but could indicate that chemical usage can be quite important in some designs and processes.

Ferchak and Pye assume that none of the lignin and a small portion of the other carbohydrate (about 14% of the weight of the dry wood) is not converted to fuel. The energy value of the lignin and the unconverted carbohydrate mash is about 90% of the energy value of the produced ethanol. This energy could be used to generate more than enough electricity to run the process. For example, some processes can export electricity at the rate of about 0.03 Btu-electric/Btu-ethanol (Hinman et al., 1989).

TABLE K.11 (Cont.)

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[p] They appear to assume that a small amount of the xylose, and none of the lignin, is converted to ethanol.

[q] Wright (1988) states that agitation costs $0.13/gal of ethanol; Wyman (1989) says $0.15/gal. This indicates roughly 2 kWh/gal, or an energy requirement of about 8%.

SERI has confirmed that 2 kWh/gal is reasonable, for current technology (Stevens, 1989). However, the technology is very young, and power consumption almost certainly will be reduced significantly with technical progress. Wyman (1989) suggests that the power cost could drop to only a "few" cents per gallon of ethanol, which implies about 1/2 kWh/gal. The wood feedstock is about 50% cellulose and 25% xylose at 7,400 Btu/lb, and 25% lignin at 11,300 Btu/lb. Wright states that in the current separate hydrolysis and fermentation (SHF) process, 73% of the cellulose in the feed wood is converted to ethanol, and the xylose and lignin are burned for process heat. This indicates that the energy in the parts of the wood feed used for process heat exceeds the energy in the feed converted to ethanol by a factor of about two. The relatively low conversion of wood to fuel also makes the ethanol product relatively expensive. To reduce the cost of ethanol, the xylose and perhaps lignin fractions must also be converted to fuel. The difficulty with xylose is that standard industrial yeast will not ferment it; the difficulty with lignin is that chemical rather than biological conversion is required. The state of the art in xylose and lignin conversion is reviewed in SERI's *FY Ethanol from Biomass Annual Report*, SERI/SP-231-3521, June (1989). Note that the most recent plans convert the xylose but burn the lignin to provide process heat.

Wright's estimate for enzymatic hydrolysis uses no xylose or lignin conversion. It is not clear if wood drying is included or if it is necessary.

[r] Lynd states that overall thermal efficiency for high-yield processes is 45%-60% and implies that electricity is produced on-site by burning the unconverted lignin. It is not clear if feed drying is included.

[s] The authors estimate that a process using both the xylose and the lignin as boiler fuels would generate surplus electricity worth 4.62 cents/gal. Assuming 8 cents/kWh, the result is 0.023 Btu-electric surplus per Btu of ethanol.

[t] These are unpublished estimates from researchers in the field. The process converts cellulose and xylose to ethanol, and uses all the lignin as a boiler fuel. The process produces substantial excess electricity.

[u] High end of range is "present case"; low end is "future case." Apparently assumes pre-dried wood chips and apparently does not require oxygen. In both cases, the char contains most of the input energy not lost or converted to gasoline; a portion of the char is burned to provide process heat, and a portion is packaged as char product.

[v] High end of range is 1987 value; low end is most optimistic goal.

TABLE K.12 Release or Uptake of Greenhouse Gases in a Biofuel Program, in Metric Tons of CO_2 or CO_2-Equivalent Emissions per Acre, as a Result of Changes in Land Use

Possible Releases of CO_2, per Acre						Possible CO_2 Uptake, per Acre			
CO_2 from Oxidation of Previous Biomass[a]			CO_2 from Soil			By Soil		By First Planting	
Grassland	Open Woodland	Dense Forest	Range to Crop	Forest to Crop	N_2O from Soil	Crop to Corn	SRIC	SRIC	SRIC
~10[b]	40-60[c]	100-300[d]	23[e]	90[f]	0.2[g]	7[h]	0-?[i]	7-11[j]	40-60[k]

SRIC = Short-rotation intensive cultivation.

[a] "Biomass" includes all above-ground plant material, dead or alive, and the belowground root system. "Soil" refers to all other belowground carbon (generally to the first meter of depth). The numbers shown assume that all of the biomass carbon eventually oxidizes to CO_2 but say nothing about the rate of oxidation. Generally, a portion of the biomass will be burned immediately, a portion will rot in a few years, a portion will rot over many years, part will be used as wood and last for a century, and some, perhaps, will be permanently remain as as charcoal (Houghton et al., 1983).

[b] Whittaker and Likens (1973; 3 metric tons of carbon per acre); Hall (1990; 6-11 tons of carbon/hectare in the U. S.).

[c] Whittaker and Likens (1973; 11 metric tons of carbon per acre of woodland and shrubland); Detwiler and Hall (1988; 11-15 metric tons of carbon per acre of primary, open tropical forest); Hall (1990; 27 tons of carbon per hectare in the U. S., and 21-120 in Africa and Asia).

[d] Whittaker and Likens (1973; 36 metric tons of carbon per acre for boreal forests, 81 for tropical rain forests); Detwiler and Hall (1988; 33-60 metric tons of carbon per acre for primary, closed tropical rain forests); Birdsley (1990; 38 metric tons of carbon per acre of spruce/fir forest in northeastern U. S., and 76 metric tons of carbon per acre of loblolly pine forest in the southeastern U. S.); Hall (1990; 80-200 tons of carbon/hectare closed forests).

[e] Burke et al. (1989).

TABLE K.12 (Cont.)

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[f] Forest soils contain 88-206 metric tons carbon per hectare, depending on type and age of the forest (Schlesinger 1977; Birdsley 1990, shows a similar range), and the conversion of forests to agriculture releases 40-50% of the carbon in the soil (Detwiler and Hall, 1988; Woodwell et al., 1983; Houghton et al., 1983). A typical release is about 60 metric tons of carbon/hectare, or 24 metric tons per acre, or about 90 metric tons of CO_2 per acre. Hall (1990) shows a lower estimate.

[g] Emissions from cleared forests. Bowden and Bormann (1986) found that 0.33 kg of nitrogen degassed as N_2O from water in forest soil, per hectare of cleared land, and said that a "similar" amount degassed from the soil itself. Taking "similar" to mean "same," and using an N_2O-to-CO_2 conversion factor of 290 (Table 8), the result is 244 kg CO_2-equivalent emissions per acre of cleared forest, or 0.244 metric tons per acre (which I round to 0.2). They did not report N_2O emissions from soils of cleared grasslands or other ecosystems.

[h] This is the CO_2 uptake from an intensive program to build organic matter in the soil, relative to no such program. Assumes a build-up of 0.73 metric tons of CO_2 per year (Homberg 1988), for what I assume is a maximum of 10 years, before oxidation of soil carbon equals uptake. Wallace et al. (1990) imply that 0.26 metric ton of CO_2 could be sequestered per acre per year for 100 years, but they appear to have overlooked oxidation of the organic matter.

[i] Cropland to SRIC. Reliable data are not available. However, it probably is reasonable to assume that the carbon content of the soil of SRIC systems will be similar to the soil carbon content of crop systems and much less than the content of undisturbed, natural forests. The ground in an SRIC system will be kept free of detritus, to supress weeds and facilitate movement between rows, and will be disturbed frequently by planting and harvesting, whereas in a natural forest, the soil is covered with litter and low-growing plants and remains relatively undisturbed.

[j] Whittaker and Likens (1973) report 2 metric tons of carbon per acre of "cultivated land," generally. Blankenhorn et al. (1985) measured 16 dry metric tons of corn specifically, per hectare. Assuming 48% carbon by weight, the result is 3.1 metric tons of carbon per acre. The difference between Birdsley's (1990) estimate of total carbon for cultivated systems and Burke et al.'s (1989) measurement of carbon in the soil of cultivated land is about 2 metric tons per acre. Hall (1990) cites an estimate of 5 tons of carbon per hectare, or 6.7 metric tons of carbon per acre.

[k] Assuming a growth rate of about 5-8 English tons per acre per year (see Table K.10; Wyman and Hinman, 1990, assume 7 English tons), a five-year growth period before the first harvest, and 48% carbon by weight.

TABLE K.13 Data Used to Calculate Energy Balance of Using Corn-Crop Residue as a Fuel

Residue			Collection Energy (10^6 Btu/ton)	Nutrient Loss (tons/ton-residue)			% Corn Loss per Ton/Acre
Available Ton/Acre	Removable Ton/Acre	HHV Btu/Ton		N	P	K	
2.45-2.6[a]	1.5-2.0[b]	15-16[c]	0.14-0.84[d]	0.0075	0.001	0.0045	0.3-3.2[f]

[a] Starr et al. (1978), SERI (Flaim, 1979; Duave and Flaim, 1979), and Pimentel et al. (1981). Chambers et al. (1979) report an estimate of 3.6 tons/acre, but the estimates by the others, particularly SERI, are of higher quality.

[b] SERI (Flaim, 1979; Duave and Flaim, 1979) and Pimentel et al. (1981). SERI estimates the amount of residue that can be removed without exceeding soil-loss limits set by the U. S. Soil Conservation Service.

[c] For dry residue with 15% moisture (Green, 1975; Starr, 1978). With higher moisture content, the value is about 12 × 10^6 Btu ton (Pimentel et al., 1981; Chambers et al., 1979).

[d] Starr et al. (1978) estimated that collection, preparation, and delivery of residue would require from 2.17 to 4.16 gal of diesel fuel per ton of residue, with most of the energy being used to collect, bale, and grind the residue. The total excluding transportation was 2.05 to 4.04 gal/ton, which is 284,000-560,000 Btu/ton, or 2-4% the energy value of the residue.

Starr et al. (1978) do not include energy for drying, since 15%-moisture crops will not spoil and can be shredded and fired in coal-fired boilers. Maurya et al. (1980) calculated that to collect (but not transport) residue required about 6% of the energy content of the residue.

Pimentel et al. (1981) estimate that 1.3% of the energy value of the residue is required to collect (not transport) the residue.

The estimate by Starr et al. (1978) is most detailed and seems most reliable.

[e] Pimentel et al. (1981) calculate that a ton of residue contains 0.01 ton of nitrogen, 0.001 ton of phosphorus, and 0.009 ton of potassium. If the ton of residue is removed, these nutrients are no longer available.

There is an additional loss of nutrients from soil eroded as a result of removing the residue. On flat land, and with conservation tillage, each ton of residue removed causes additional erosion of 0.53 ton; on steeper land, with conventional tilage, the loss is 2.57 tons/ton-residue removed; and with no tillage and a cover crop, there is no extra loss loss (Pimentel et al., 1981). 0.005 ton of nitrogen and 0.001 ton of phosphorus are lost per ton of erosion. Assuming 1 ton of erosion per ton of residue removed, on average, the result is 0.005 ton of nitrogen and 0.001 ton of phosphorus per ton of residue removed. This is added to the loss from the removed residue itself. The total is 0.015 ton of nitrogen, 0.002 ton of phosphorus, and 0.009 ton of potassium lost per ton of residue removed.

TABLE K.13 (Cont.)

Pimentel et al. apparently assume that if the residue were not removed, it would be left on the ground to prevent erosion and provide nutrients. However, analysts familiar with corn-farming practices indicate that about half the corn stover is not used to control erosion and provide nutrients but simply is burned in the field. (In support of this, I note that only about 20% of corn-farming land is covered with residue after planting, according to the USDA's *Agricultural Resources*, 1989.) When the stover is burned, it loses most of its nutrients, and it no longer protects against erosion. Hence, if this stover that normally would be burned in the field were instead burned at the corn-to-ethanol facility, there would be little change in soil erosion or nutrient content. To account for this, I reduce the results calculated above, from the Pimentel et al. data, by a factor of 2.0. (Note that the failure to use nutrients in the stover that is burned in the field is implicitly accounted for in the fertilizer-use data calculated in Tables K.1 to K.3, because those are real data from current practice.)

[f] Percent reduction in corn yield, per ton of residue removed, per acre. Pimentel et al. (1981) estimate that the removal of 3.85 tons of residue from a hectare (not an acre) of conventionally tilled land with a slope of 6-12% reduces corn yields by an average of 10% over 30 years. On flat land with conservation tillage, the removal of 4.19 tons of residue from a hectare reduces corn yield by 1%. This indicates 0.24-2.6% reduction per ton/hectare removal rate, or 0.6-6.4% ton/acre removed.

However, as discussed in note e above, not all the stover would remain on the ground in any case — some would be burned and effectively wasted. As per note e, I assume that half the stover would have been burned anyway, which means that only half of the stover removed for fuel actually would contribute to further erosion.

Appendix L:

Hydrogen

Appendix L:

Hydrogen

L.1 Overview*

Hydrogen is a very attractive transportation fuel in two important ways: it is the least polluting fuel that can be used in an internal combustion engine, and it is potentially available anywhere there is water and a clean source of power. The prospect of a clean, widely available transportation fuel has motivated much of the research on hydrogen fuels.

Serious work on hydrogen vehicles began in the 1930s, when Rudolph Erren converted over 1,000 vehicles to hydrogen and hydrogen/gasoline operation in England and Germany. However, interest in the fuel waned after World War II. The resurgence of research and experimental activity came in the late 1960s and early 1970s as programs began in Europe, Canada, the Soviet Union, Japan, and the United States.

L.1.1 Hydrogen Production

Elemental hydrogen occurs freely on earth in only negligible quantities. It is chemically very active, readily forming compounds with many other elements. Hydrogen is most abundant and accessible in water and the fossil fuels: coal, oil, and natural gas. Of the fossil fuels, coal is by far the most plentiful.

Of course, hydrogen derived from fossil fuels is not a clean, renewable resource. Most of the hydrogen research community agrees that eventually hydrogen should be produced from water. There are several methods for splitting water to produce hydrogen: thermal and thermochemical conversion, photolysis, and electrolysis. Of these, electrolysis, or splitting of water with electricity, is the most attractive at present.

When hydrogen is produced from water electrolytically, the ultimate energy source is the feedstock used to generate the electricity. Fossil fuels would not be used, because it would be cheaper and more efficient and would generate less carbon dioxide (CO_2) to gasify the coal, oxidize the oil, or reform the natural gas directly to produce hydrogen. Nonfossil feedstocks, such as solar, geothermal, wind, hydro, and nuclear energy, would be used. Of these, solar energy and nuclear energy (from breeder reactors or, possibly, fusion plants) are available for the long term. This report considers both solar and nuclear energy as hydrogen feedstocks.

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*From DeLuchi, "Hydrogen Vehicles," in Sperling, ed., 1989.

L.1.2 Hydrogen Distribution

Hydrogen probably will be transported via pipeline from the site of production to end users as a gas. Ideally, the current natural gas pipeline distribution system will be used for at least the initial stages of a transition to hydrogen. (It appears that if certain compounds are added to the hydrogen the natural gas system can be used.) Hydrogen also can be shipped in liquid form, in 13,000-gal tank trucks, 35,000-gal rail cars, or, for short distances, in vacuum-jacketed pipelines.

L.1.3 Use of Hydrogen in Vehicles

Hydrogen may be stored on board a vehicle as a gas bound with certain metals (hydrides), as a liquid (LH_2) in cryogenic containers, or as highly compressed gas (690 atm) in ultra-high-pressure vessels. All of these systems are bulky and costly. In this paper, the two most common forms of hydrogen storage, as LH_2 or as a hydride, are analyzed.

Vehicular hydride storage systems usually consist of long, thin hollow cylinders filled with granular metal alloy, a heat exchange system, and a casing. They are pressurized with hydrogen to about 500 psi. Exhaust heat from the engine, carried by cooling water, is used to release the hydrogen from the metal lattice during vehicle operation.

Liquid hydrogen is stored in double-walled, super-insulated vessels designed to minimize heat transfer and the boil-off of LH_2. It takes a good deal of energy to liquefy hydrogen and, as shown in this report, the use of this energy can result in surprisingly high levels of greenhouse gases.

For a recent analysis of a solar-hydrogen energy system for the United States, see Ogden and Williams (1989). For a recent review of hydrogen as a transportation fuel, see DeLuchi, *International Journal of Hydrogen Energy* (1989).

L.2 Emissions of Greenhouse Gases from the Production and Use of Hydrogen

Greenhouse gases can be emitted at several points in the hydrogen production and use cycle: from the manufacture and assembly of materials used to make nuclear or solar power plants, hydrogen pipelines, and hydrogen vehicles; from the nuclear fuel production and use cycle; from the combustion of hydrogen used in pipeline compressors (presumably, a small amount of nitrous oxide [N_2O] and nitrogen oxide [NO_x] will be produced); from the use of electricity to compress or liquefy hydrogen; and from the tailpipe of internal combustion engine vehicles (ICEVs).

As shown in Appendix P, emissions from the manufacture and assembly of materials used to make pipelines and power plants probably are very small. Emissions from materials manufacture and assembly for vehicles are not so small; they are quantified in that appendix and included in the results here. This appendix discusses the calculation of emissions from hydrogen production, distribution, and compression or liquefaction. Emissions from vehicles are discussed in Appendix B.

L.2.1 Emissions from Nuclear-Electrolytic Hydrogen Production

If hydrogen is produced from solar-photovoltaic power, there are no emissions of any kind, except from materials manufacture. If hydrogen is produced from nuclear power, there are emissions from the mining, transport, conversion, and enrichment of nuclear power, as discussed in Appendix I. Emissions per unit of end-use hydrogen energy are equal to:

$$G_h = G_n \times El \times (1 + T) \times (1 + O) \times (1 + L) \times (1 + B)$$

where:

G_h = grams of greenhouse gases per energy unit of hydrogen consumed by vehicles,

G_n = grams of greenhouse gases per energy unit of nuclear power from the reactor,

El = nuclear energy from the reactor per unit of hydrogen energy produced by electrolysis (the reciprocal of efficiency of electrolysis),

T = energy units of hydrogen consumed by pipeline compressors per energy unit delivered to hydrogen stations,

O = own use or the amount of hydrogen consumed by power plants supplying electricity to hydrogen compression or liquefaction stations per unit of hydrogen delivered to vehicles,

L = hydrogen leaks from pipelines per unit of hydrogen delivered to vehicles, and

B = amount of LH_2 that boils off and is lost to the atmosphere per energy unit of LH_2 consumed by the vehicle.

These variables are treated as follows:

1. G_n — The calculation of greenhouse gas emissions per unit of nuclear power is detailed in Appendix I. In the case of hydrogen, I examine the effect of changing the energy requirement of uranium enrichment from that of gaseous diffusion to that of laser isotope separation, because a large, future nuclear-electrolytic hydrogen program would greatly increase demand for nuclear power and require new enrichment capacity.

2. El — The efficiency of electrolysis (1/El) depends on the kind of electrolyzer; 83% probably is representative of future technology (DeLuchi, *International Journal of Hydrogen Energy*, 1989; Ogden and Williams, 1989).

3. T — I estimate T to be about 0.1 (DeLuchi, 1989; Ogden and Williams, 1989).

4. O — Use of hydrogen at stations supplying electricity to compression or liquefaction facilities is calculated from data on the amount electricity consumed per unit of hydrogen produced (discussed below) and the percentage of that electricity generated from hydrogen. Presently, I assume this percentage to be zero.

5. L — Estimated to be half the volumetric leakage rate with natural gas. Swain and Swain (1990) found that the energy leakage rate from a hydrogen pipeline was 46% of the leakage rate from a natural gas pipeline when both systems delivered energy to end users at the same rate. This means that the volumetric leakage rate with hydrogen was 46% of the volumetric leakage rate with natural gas. (To see this formally: the kJ/mole value for hydrogen is 32% of the value for natural gas [Table C.3], which means that the hydrogen pipeline, compared to the natural gas pipeline, was delivering 3.12 times as many moles/s, and leaking 1.43 times [0.46 × 3.12] as many moles/s. This means that the hydrogen volumetric leak rate, compared to the natural gas volumetric leakage rate, was 1.43/3.12 = 0.46.)

6. B — Estimated to be about 0.01 (DeLuchi, *International Journal of Hydrogen Energy*, 1989); it could vary from 0 to 0.1. See Appendix B for details.

L.2.2 Emissions from Hydrogen Transport by Pipeline

Presumably, the combustion of hydrogen in a pipeline compressor will produce some N_2O from the atmospheric nitrogen. For want of data, I assume that hydrogen combustion in pipeline compressors produces N_2O at the same rate (in grams per million Btu of fuel burned) as does natural gas combustion for electricity generation.

L.2.3 Emissions from Compression or Liquefaction of Hydrogen for End Use

The results of this report show that compression or liquefaction of hydrogen — especially liquefaction — produces nontrivial amounts of greenhouse gases. These emissions are attributable to the burning of fossil fuels to produce electricity.

The amount of energy required to compress hydrogen is strongly dependent on the ratio of the final pressure to the initial pressure. Ogden and Williams (1989) calculate that compressing hydrogen from 300 psi (the pressure of transmission lines) to 750 psi (for delivery to hydrides), requires about 0.01 Btu-electric/Btu-hydrogen. If the hydrogen is delivered to the station through a low-pressure (14.7-psi) distribution line, the compression electricity requirement increases to about 0.06 Btu-electric/Btu-hydrogen (my calculation, using Ogden and Williams' formula relating compressor capacity to input and output pressure).

Currently, state-of-the art hydrogen liquefaction requires about 0.30 Btu-electricity/Btu-LH_2 produced (DeLuchi, *International Journal of Hydrogen Energy*, 1989; private communications from Allied Signal). With advanced technology expected by the year 2000, the electricity requirement could drop to 0.26 Btu-electric/Btu-LH_2 (Blazek et al., 1986). However, this must be adjusted for vaporization losses during transfers between the liquefaction plant and the vehicle. The LH_2 probably will be made at large centralized facilities and, in many cases, will be transferred three times (i.e., production plant to truck, truck to station, and station to vehicle) before it reaches the vehicle. At least 10% of the LH_2 will vaporize at each transfer if the lines and tanks are warm; if they are cold, about 5-7% will vaporize (DeLuchi, *International Journal of Hydrogen Energy*, 1989; private communications from LH_2 suppliers). On average, around 16% of the LH_2 will boil off, all told. Thus, overall, about 84% of the originally liquefied LH_2 will reach the vehicle as LH_2, which means that the liquefaction energy requirement per unit of LH_2 *delivered* to the motorist will be higher than the energy requirement per unit of LH_2 *produced* — 0.26/0.84 = 0.31 Btu-electric/Btu-LH_2-delivered.

The vaporization loss and, hence, the energy requirement per unit of LH_2 delivered to motorists, could be greatly reduced if LH_2 could be liquefied at the point where it would be dispensed to vehicles because this would eliminate two of the three transfers. However, small-scale liquefaction does not appear to be economical.

Because the amount and kind of electricity used to compress or liquefy hydrogen is an important determinant of emissions of greenhouse gases from the use of hydrogen, the electricity mix for hydrogen compression or liquefaction can be specified separately from the other mixes. In sensitivity analyses, I investigate the effect of changing the mix.

L.2.4 Calculation of Net Hydrogen Available to the Transportation Sector

The amount of energy needed to provide a unit of hydrogen to the transportation sector depends, in part, on how much hydrogen is lost to leakage or boil-off, and how much is consumed along the way as a process fuel. The model accounts for all of these losses or uses, albeit in a somewhat simplified fashion.

In calculating the amount of hydrogen that must be produced to support net consumption, I ignore hydrogen used to generate electricity used to mine, convert, enrich, or otherwise process uranium used to make nuclear power used to electrolyze water to produce hydrogen. Since relatively little electricity (compared to the output of the nuclear plant) is used for these processes, and little of that will come from hydrogen for many years to come, this simplification does not seriously affect the results. I do, however, account for hydrogen used to generate the electricity used to compress hydrogen. I account for the hydrogen consumed by pipelines in the transmission of hydrogen to service stations, but do not account for hydrogen used by pipelines to transmit the hydrogen used to generate the electricity used to compress or liquefy hydrogen.

Finally, emissions per unit of hydrogen energy consumed are converted to emissions per mile by multiplying by million Btu per mile, which is calculated relative to the miles-per-gallon efficiency of the comparable gasoline or diesel vehicle, as explained in Appendix B.

In summary, I estimate:

1. 0.03 Btu of electricity is used per each Btu of hydrogen that is compressed for hydrides.

2. 0.26 Btu of electricity is used for liquefaction per each Btu of liquid hydrogen that is produced.

3. 0.31 Btu of electricity is used for liquefaction per each Btu of liquid hydrogen that is delivered to motorists.

4. 0.10 Btu of hydrogen is consumed by pipeline for each Btu of hydrogen that is delivered.

Appendix M:

Emissions of Methane from Vehicles, Natural Gas Operations, Oil Production, Coal Mines, and Other Sources

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Emissions of Methane from Vehicles, Natural Gas Operations, Oil Production, Coal Mines, and Other Sources

M.1 Methane as a Greenhouse Gas

According to the Intergovernmental Panel on Climate Change (IPCC) (*Climate Change*, 1990), methane (CH_4) will contribute more to global warming than any other non-CO_2 greenhouse gas — about 15% of the total warming over the next century. Molecule per molecule, methane has about 20 times the radiative forcing of carbon dioxide (CO_2), although it also has a much shorter lifetime (Appendix O). When methane is destroyed by the hydroxyl radical (OH), it forms CO_2 and water vapor (H_2O), both greenhouse gases.

The concentration of methane was relatively constant for 2,000 years prior to 1600 A.D., started increasing rapidly about 150 years ago, and is now increasing at roughly 1.0% per year (Ramsussen and Khalil, 1984; Stauffer et al., 1985; Ramanathan et al., 1985; Bolle et al., 1986; Pearman et al., 1986; Watson et al., 1990). The increase between 1600 A.D. and today, from about 0.8 parts per million volume (ppmv) to 1.72 ppmv, may have caused an 0.23°C warming worldwide (Chameides, 1983). And the current percent rate of increase in the concentration of methane will increase, if the rising global mean temperature excites the release of methane from hydrates in permafrost and ocean sediments and establishes a positive feedback cycle. An increase in the concentration of methane may also result in increases in ozone (O_3), which also is a greenhouse gas (Ramanathan, 1988).

Most methane comes from the anaerobic fermentation of organic matter in rice paddies and swamps and from the fermentation of mammalian organic excrement (Ramanathan et al., 1985; Bolle, et al., 1986; Mooney et al., 1987; Whalen et al., 1989; Watson et al., 1990). The decline in the concentration of OH, the principal scavenger of methane (via the reaction, $CH_4 + OH \longrightarrow CH_3 + H_2O$), due to an increase in carbon monoxide (CO) ($2CO + HO \longrightarrow 2CO_2 + H_2$), may also be a factor (Stauffer et al., 1985), as might be an increase in decaying plant matter. The use of fossil fuels accounts for 10-20% of yearly global methane emissions (Ehhalt and Schmidt, 1978; Bingemer and Crutzen, 1987; Whalen et al., 1989; Watson et al. ,1990).

M.2 Methane from Vehicles

Methane is a combustion product of gasoline, diesel, methanol, ethanol, liquified petroleum gas (LPG), and natural gas internal-combustion-engine (ICE) vehicles. Table M.1 is a compilation of reported measurements of emissions from petroleum- and alternative-fuel-powered vehicles.

TABLE M.1 Methane Emissions from Highway Vehicles

Type of Vehicle	Emission Control Equipment	Test^a	Odometer	Methane (g/ml)	Reference
Gasoline LDV					
1978 Ford Fairmont	NS	NS	NS	0.05-0.08^b	Aerospace (1982)
(12) 1977-1981 passenger cars	NS	NS	NS	0.02-0.18 [0.06]^b	Aerospace (1982)
1978 Oldsmobile Cutlass^c	Oxygen catalytic converter and EGR	FTP-75	NS	0.06-0.08	Urban and Garbe (1979)
1979 Chevrolet Impala	Oxygen catalytic converter and EGR	FTP-75	New	0.06	Peninga (1981)
1980 Dodge Diplomat	Oxygen catalytic converter and EGR	FTP-75	New	0.11	Peninga (1981)
(4) 1978-1980 passenger cars^d	3-way catalytic converter and EGR; 2 cars with oxygen catalytic converter	FTP-75	New	0.09-0.39	Braddock (1981)
(4) 1978-1979 passenger cars^e	3-way catalytic converter; 2 cars with oxygen catalytic converter	FTP-75	New	0.03-0.11 [0.07]	Smith and Black (1980)
(16) 1975-1978 passenger cars	Various	FTP-75	Various	0.19-0.32	Sigsby et al. (1987)
(30) 1979-1982 passenger cars	Various	FTP-75	Various	0.14-0.18	Sigsby et al. (1987)
1985? Chevrolet S-10 truck	Oxygen catalytic converter and EGR	FTP-75	~4,000	0.02	BC Research (1986)
1985? Dodge 600es truck	3-way catalytic converter	FTP-75	~4,000	0.02	BC Research (1986)
1985? Ford F250 truck	No catalytic converter	FTP-75	~4,000	0.20	BC Research (1986)
1981 Volkswagon Rabbit (MeOH control)*	3-way catalytic converter	FTP-75	25,000	0.03	CARB (1985)
1981 Ford Escort (MeOH control)*	3-way catalytic converter	FTP-75	38,000	0.23	CARB (1985)
1984 Ford Mustang (MeOH control)*	3-way catalytic converter	FTP-75	1,000	0.14^f	Gabele et al. (1985)
1984 Chevrolet Cavalier (MeOH control)*	3-way catalytic converter	FTP-75	4,500	0.04^f	Gabele et al. (1985)
1984 GM Delta 88 (CNG control)*	3-way catalytic converter and EGR	FTP-75	High	0.10	Bruetsch (1988)
1987 Ford Crown Victoria (CNG control)*	3-way catalytic converter and EGR	FTP-75	Low	0.11	Bruetsch (1988)
1987 GM Celebrity (CNG control)*	3-way catalytic converter and EGR	FTP-75	Low	0.02	Bruetsch (1988)

TABLE M.1 (Cont.)

Type of Vehicle	Emission Control Equipment	Test^a	Odometer	Methane (g/mi)	Reference
(5) 1987 Ford Crown Victorias (MeOH control)*	3-way catalytic converter	FTP-75	0-16,000	0.08-0.15 [0.10]	CARB (June, 1988)
(2) 1987 Ford Crown Victorias (MeOH control)*	3-way catalytic converter	FTP-75	11,000-22,000	0.078	CARB (1989)
(9) 1984-1987 4-cylinder passenger cars	Various	FTP-75	3,000-62,000	0.08-0.15	Stump et al. (1989)
(11) 1985-1987 4-8 cylinder cars	Various	FTP-75	7,000-64,000	0.13-0.20	Stump et al. (1989)
- - - - - - - - - - - - - - - - - - -					
Carb lifetime average factor	3-way catalytic converter	FTP-75	50,000	0.056^g	CARB (1986)
EPA lifetime average factor (1981+)	3-way catalytic converter	FTP-75	Over life	0.10	EPA (1985)
MOBILE4 emission factor (1990-2020)			Fleet average	0.04-0.12	My runs of MOBILE4
<u>Gasoline HDV</u>					
Ford truck	NS	Chassis HDTC	11,000	2.13	Dietzmann et al. (1981)
International Harvester truck	NS	Chassis HDTC	15,000	0.28	Dietzmann et al. (1981)
5 trucks, 1973-1980	NS	Chassis HDTC	35,000-105,000	0.4-1.0	Black et al. (1984)
- - - - - - - - - - - - - - - - - - -					
EPA lifetime average factor (1987+)	None	HDTC	Over life	0.18	EPA (1985)
MOBILE4 emission factor (1990-2020)			Fleet average	0.18-0.28	My runs of MOBILE4
<u>Diesel HDV</u>					
1979 Caterpillar 4-stroke	NS	Chassis HDTC	7,000	0.05	Dietzmann et al. (1981)
1979 Mack 4-stroke	NS	Chassis HDTC	69,000	~0	Dietzmann et al. (1980)
1979 Cummins 4-stroke	NS	Chassis HDTC	26,000	~0	Dietzmann et al. (1980)

TABLE M.1 (Cont.)

Type of Vehicle	Emission Control Equipment	Test^{a}	Odometer	Methane (g/mi)	Reference
1977 DDC 2-stroke	NS	Chassis HDTC	60,000	~0	Dietzmann et al. (1980)
CARB lifetime average factor	None	HDTC	150,000	0.16^{h}	CARB (November, 1986)
EPA lifetime average factor (1987+)	None	HDTC	Over life	0.10	EPA (1985)
MOBILE4 emission factor (1990-2020)			Fleet average	0.10-0.12	My runs of MOBILE4
<u>Natural Gas Dual-Fuel LDV</u>					
1980 Dodge Diplomat	Oxygen catalytic converter and EGR	FTP-75	New	1.09	Peninga (1981)
1979 Chevrolet Impala	Oxygen catalytic converter and EGR	FTF-75	New	0.66	Peninga (1981)
1985? Chevrolet S-10 truck	Oxygen catalytic converter and EGR	FTP-75	~4,000	0.7-2.5^{i}	BC Research (1986)
1985? Dodge 600es truck	3-way catalytic converter	FTP-75	~4,000	0.6-1.4^{i}	BC Research (1986)
1985? Ford F250 truck	No catalytic converter	FTP-75	~4,000	1.83-5.64^{i}	BC Research (1986)
1978 Ford Fairmont^{b}	NS	NS	NS	1.47-1.81	Aerospace (1982)
(12) 1977-1981 passenger cars^{b}	NS	NS		0.60-3.13 [1.40]	Aerospace (1982)
1985 Ford Ranger	3-way catalytic converter	FTP-75	NS	2.19-4.38	Overby and Regdon (1987)
1984 GM Delta 88	3-way catalytic converter and EGR	FTP-75	High	2.37-2.46^{j}	Bruetsch (1988)
1987 Ford Crown Victoria	3-way catalytic converter and EGR	FTP-75	Low	3.03-3.55^{j}	Bruetsch (1988)
1987 GM Celebrity	3-way catalytic converter and EGR	FTP-75	Low	1.41-1.50^{j}	Bruetsch (1988)
1986 Mercury Marquis	3-way catalytic converter ?	FTP-75	NS	2.63-3.59	Natural Gas Vehicle Coalition (1989)
1986 Buick	3-way catalytic converter	FTP-75	25,000	1.803	CARB (1989)

TABLE M.1 (Cont.)

Type of Vehicle	Emission Control Equipment	Test[a]	Odometer	Methane (g/mi)	Reference
Natural Gas Dedicated LDV					
1983 Ford 3.81 V-6	None	EPA-CVS	New	0.9-2.5[k]	Swain et al. (1983)
1984 Ford Ranger Pickup	Oxygen catalytic converter and EGR	FTP-75	Low	1.06	Adams (1985)
1984 Ford Ranger Pickup	Oxygen catalytic converter and EGR	FTP-75	NS	1.17-1.31[j]	Bruetsch (1988)
1989 Dodge Van	3-way catalytic converter	FTP-75	4,000	1.44	Gabele (1990)
Natural Gas HDV					
Diesel dual-fuel pilot	NS	SAE 13-mode	NS	27.2[1]	BC Research (1987)
GMC 454 CID V-8 bus engine	3-way catalytic converter	Modified HDTC	Low	0.6[m]	Goetz (1988)
GMC 454 CID V-8 bus engine	3-way catalytic converter	Modified HDTC	Low	2.4[m]	Goetz (1988)
GMC 454 CID V-8 bus engine	3-way catalytic converter	HDTC	Low	1.92[n]	Alson et al. (1989)
Cummins L-10 lean-burn engine	No catalytic converter	13-mode test	NS	4.0[m]	Lawson (1988)
Methanol Dual-Fuel LDVs					
(7) 1987 Ford Crown Victorias (M85)	3-way catalytic converter	FTP-75	0-16,000	0.02-0.06 [0.04]	CARB (June, 1988)
(7) 1987 Ford Crown Victorias (M50)	3-way catalytic converter	FTP-75	0-16,000	0.05-0.10 [0.07]	CARB (June, 1988)
1988 Chevrolet Corsica (M100)	3-way catalytic converter	FTP-75	4,000	0.003	CARB (June, 1988)
1988 Chevrolet Corsica (M50)	3-way catalytic converter	FPT-75	4,000	0.01	CARB (June, 1988)
(2) 1987 Ford Crown Victorias (M85)	3-way catalytic converter	FTP-75	11,000-22,000	0.044	CARB (1989)
(2) 1987 Ford Crown Victorias (M100)	3-way catalytic converter	FTP-75	11,000-22,000	0.021	CARB (1989)

TABLE M.1 (Cont.)

Type of Vehicle	Emission Control Equipment	Test[a]	Odometer	Methane (g/mi)	Reference
Methanol Dedicated LDVs					
(2) 1981 Volkswagon Rabbit (M85)	3-way catalytic converter	FTP-75	4,500	0.01-0.02	CARB (1985)
Same cars as above (M90)	3-way catalytic converter	FTP-75	22,000	0.02-0.03	CARB (1985)
Same cars as above (M85)	3-way catalytic covnerter	FTP-75	56,000-66,000	0.03-0.13	CARB (June, 1988)
(2) 1981 Ford Escort Wagons (M90-95)	3-way catalytic converter	FTP-75	5,000-50,000	0.07	CARB (1985)
1981 Ford Escort Wagon (M90)	3-way catalytic converter	FTP-75	85,000-115,000	0.09	CARB (1985)
(8) 1983 Ford Escort Wagons (M90)	3-way catalytic converter	FTP-75	0-20,000	0.01-0.14 [0.06][o]	CARB (1985)
1982 Chevrolet Citation (M85-90)	3-way catalytic converter	FTP-75	30,000-40,000	0.03	CARB (1985)
1983 Pontiac Phoenix (M85)	3-way catalytic converter	FTP-75	2,400	0.02	CARB (1983)
1983 Ford Escort (M90)	3-way catalytic converter	FTP-75	1,500	0.06	Gabele et al. (1985)
1981 Volkswagon Rabbit (M100)	Heated catalytic converter[p]	FTP-75	NS	0.01	Blair and Piotrowski (1988)
1985 Toyota Camry (M85)	3-way catalytic converter	FTP-75	0-26,000	0.02	CARB (June, 1988)
1985 Toyota Camry (M85)	No catalytic converter	FTP-75	0-26,000	0.02	CARB (June, 1988)
1986 Toyota Carina (M85)	3-way catalytic converter	FTP-75	0-9,000	0.02	CARB (June, 1988)
1987 Ford Crown Victoria (M85)	3-way catalytic converter	FTP-75	2,500	0.04	CARB (June, 1988)
Methanol HDVs					
MAN spark-ignited 6-cylinder engine	Oxygen catalytic converter	HDTC	NS	0.002[q]	Ullman and Hare (1982)
MAN spark-ignited 6-cylinder engine	Oxygen catalytic converter	r	28,300	0.04; 0.12[r]	Ullman and Hare (1986)
DDC 6V-92TA spark-assisted 2-stroke	NS	r	8,900	1.17; 0.72[r]	Ullman and Hare (1986)
Other Kinds of Vehicles					
1979 Hydrogen pick-up truck	NS	FTP-75	23,000	0	CARB (1989)
1988 dual-fuel LPG Chevrolet	NS	FTP-75	14,000	0.046	CARB (1989)
1987 Ford Crown Victoria FFV (ethanol)	NS	FTP-75	22,000	0.196	CARB (1989)

See next pages for footnotes.

TABLE M.1 (Cont.)

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[a] FTP = Federal Test Procedure. HDTC = Heavy Duty Transient Cycle, engine test; the chassis version of the HDTC tests the whole chassis, not just the engine. CVS = constant volume sample.

[b] The researchers actually *measured* methane emissions for the Fairmont. They *assumed* that methane was 80% of total HCs from 1977 NGVs, 87% from later year NGVs, and 12% from gasoline vehicles.

[c] Methane emissions increased slightly after several engine malfunctions. However, with rich idle, emissions were 0.52 g/mi.

[d] Emissions were around 0.10 g/mi for three of the four vehicles, with summer fuel at 78°F ambient temperature, but over 0.20 g/mi with winter fuel at 55°F ambient temperature.

[e] Methane emissions varied moderately with the type of gasoline, and generally increased slightly from 0-15,000 miles. Methane emissions in the NYCC cycle were higher, and in HFET lower, than in FTP.

[f] Methane was measured for the Mustang only; I assume that methane was the same percent of HC exhaust from the Cavalier as from the Mustang. The Cavalier is more similar in weight and power to the Escort than is the Mustang.

[g] Range reflects primarily different ambient temperatures. Methane emissions were lowest at 21°C,which is typical of FTP test conditions, and highest at the lowest temperature (-6.7°C).

[h] CARB estimates that 7.5% of the total organic gases (TOG) from gasoline LDVs are nonreactive. I assume that all of these nonreactive gases are methane, and that no methane is counted as reactive. I then multiplied the lifetime average TOG emission factor for LDVs by 0.076. For HDDVs, CARB assumes that 4.4% of TOG are nonreactive.

[i] Emissions varied with the conversion kit.

[j] The authors reported total HCs and four different ways of measurig NMHCs. My range is their HC minus their high NMHC to their HC minus their low NMHC.

[k] Emissions varied with spark advance and air-fuel ratio. The test cycle was an approximation of the EPA-CVS.

[l] Reported in the reference as 13 g/bhp-hr and 85-90% methane. I converted g/bhp-hr to g/mi using EPA's (1985) 2.31 factor.

[m] I assume 85% methane in total reported HCs, and use EPA's 2.31 conversion factor. The first Goetz (1988) test was by the manufacturer. The second test was by EPA. In tests reported by Goetz (1988) , HDTC was modified to reflect transit bus applications. (Also see Alson et al. (1988) for the results of other EPA tests on the GMC engine.)

[n] Conversion factor = 2.31.

TABLE M.1 (Cont.)

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[o] New vehicles tended to emit in the range of 0.03 g/mi. Older vehicles emitted around 0.06 g/mi. The average was around 0.06 g/mi. Three vehicles had electronic fuel injection.

[p] A resistively-heated-monolithic catalyst designed to reduce cold-start HC and HCHO emissions.

[q] They report 70 mg of methane in the cold-start transient test, 0 in the hot-start test, and about 0.3 kW-hr work in both tests. I used their formula (p.16) to convert these to mg/hp-hr, and then used a 2.31 conversion factor.

[r] First value emitted over bus transient cycle; second value emitted over central business district transient cycle.

* See the same type of vehicle tested on alternative fuel in this table. The 1981 Rabbit and the 1981 Escort (tested by CARB, 1985) are production-line gasoline vehicles and should be compared to the 1981 dedicated methanol Rabbits and Escorts tested by CARB (1985). The 1984 Mustang and the 1984 Cavalier (tested by Gabele et al., 1985) are also production-line gasoline vehicles and should be compared to the dedicated methanol Escort tested by Gabele et al. (1985) (see footnote f to this table). The Delta 88, the Crown Victoria, and the Celebrity (tested by Bruetsch, 1988) are dual-fuel CNG/gasoline vehicles. The 1987 Crown Victorias (tested by CARB, June 1988; 1989) are flexible fuel methanol/gasoline vehicles. The asterisked vehicles in the first part of this table and the flexible-fuel Crown Victorias shown under "Methanol Dual-Fuel LDVs" are the same.

Note: EPA testing protocol requires that all emissions be corrected for background concentration (i.e., that the ambient concentration be subtracted from gross measured emissions). I therefore have assumed that all reported emissions are net of background. (In any case, methane in exhaust is about two orders of magnitude more concentrated than is methane in ambient air.)

NS = not specified. Numbers in brackets are my approximate averages of ranges. EGR = exhaust gas recirculation. ? = model year of vehicle is not certain. NYCC = New York City Cycle. HCHO = formaldehyde. HFET = Highway Fuel Economy Test. DDC = Detroit Diesel Corporation (prior to January 1, 1988, this was Detroit Diesel Allison Division). CID = Cubic Inch Displacement. MAN = Maschinen Fabrik Augsburg-Nurnberg. MeOH = methanol.

M.2.1 Gasoline Vehicles

The data of Table M.1 show that gasoline-powered light-duty vehicles (LDVs) with 3-way catalysts emit between 0.02 and 0.2 g/mi of methane, with values for recent model-year cars centering around 0.08-0.10 g/mi. MOBILE3, the EPA's (1985) emission model, indicates 0.1 g/mi from gasoline LDVs at low altitude (details are given in Chun, 1988). MOBILE4, the recent update of MOBILE3, indicates 0.04-0.12 g/mi of methane, depending on the fleet year analyzed (Table M.1; the 0.12 figure is the difference between exhaust total hydrocarbons (THC) and exhaust nonmethane hydrocarbons [NMHCs] from light-duty gas vehicles [LDGVs] in the year 1990; the 0.04 figure is the same difference in the year 2020). For the year 2000, MOBILE4 assumes 0.05 g/mi.

Methane emissions will be reduced by the new Clean Air Act Amendments. However, it will not be reduced nearly as much (in percentage terms) as will NMHCs because the new standards exclude methane and methane is hard to oxidize catalytically. Consider, for example, the data of Table M.1, which show that emissions from catalyst-equipped vehicles are not dramatically lower than emissions from uncontrolled vehicles (compare tests on uncontrolled gasoline and natural gas vehicles versus controlled vehicles). The EPA's study for MOBILE3 found that catalyst-equipped vehicles emit only 0.2 g/mi less methane than noncatalyst vehicles — a much smaller reduction than with NMHCs.

The data of Table M.1 suggest that, for all fuels, methane emissions are not a strong function of the age of the vehicle. The EPA's (1985) analysis for MOBILE3 corroborates this, showing that methane emissions from gasoline vehicles do not deteriorate with age. It also appears that methane emissions are not a function of vehicle efficiency, based on data (not shown here) on the efficiency of vehicles in Table M.1. However, methane emissions, like THC emissions, appear to increase with decreasing temperature (Stump et al., 1989, 1990).

With these considerations, a value of 0.05 g/mi of methane appears reasonable as a lifetime average for the year 2000. This also is the MOBILE4 value for the year 2000.

M.2.2 Natural Gas Vehicles

As expected, natural gas LDVs emit at least an order of magnitude more than gasoline LDVs because methane is the primary component of natural gas. The range of reported emissions from natural gas vehicles (NGVs) is quite wide, ranging from 0.6 to 4 g/mi for dual-fuel vehicles and about 1-2 g/mi for dedicated vehicles, and shows no strong patterns with respect to age, model year, or fuel economy. Ambient temperature also is not important (Gabele, 1990). It is possible that methane emissions from NGVs will be reduced as the vehicle technology improves and the high-end emissions are eliminated. The need to meet relatively tight NMHC standards may also reduce methane emissions somewhat. An estimate between 1.0 and 2.0 g/mi, but closer to 1.0 g/mi, is most reasonable for dedicated, advanced-technology vehicles meeting a tight NMHC standard in the year 2000. Because of the importance of this value to total CO_2-equivalent emissions from NGVs, I consider lower and higher values in scenario analyses.

M.2.3 Methanol Vehicles

Methanol LDVs definitely emit less methane than do gasoline vehicles. This is indicated by comparisons of dedicated gasoline vehicles with same- or similar-model dedicated methanol vehicles (Table M.1) and by tests showing that methane emissions increase with the gasoline content of the fuel used by a flexible-fuel vehicle (FFV) (Tables M.2, M.3, and M.4). Also, the upper end of reported methane emissions from methanol LDVs is not as high as the upper end for gasoline LDVs. Table M.2 compares methane emissions from FFVs and from similar gasoline and methanol vehicles. The data indicate that dedicated 100%-methanol (M100) vehicles emit 50% as much methane as dedicated gasoline vehicles, and M85 vehicles emit about 66% as much. The model used here follows the data of Tables M.1 and M.2 and assumes that emissions from gasoline/methanol mixtures are equal to the M100 emission rate multiplied by the methanol fraction, plus the gasoline emission rate multiplied by the gasoline fraction of the mixture.

Note that it is very important to compare *same or similar* methanol and gasoline vehicles. As shown in Table M.1, methane emissions for both gasoline and methanol vehicles can range from nearly zero to over 0.1 g/mi, and if one randomly picks a few test results for gasoline vehicles and a few for methanol, one may find that methanol vehicles emit a lot more methane than do gasoline vehicles, or vice-versa. The correct method is to compare methane emissions from vehicles with the same basic engine, fuel injection, mileage, emission control equipment, vehicle weight, etc. This is correct because manufacturers will build either a gasoline vehicle or a methanol version of the *same* vehicle, depending on economics, environmental regulations, and so on.

M.2.4 Ethanol, Liquefied Petroleum Gas, and Hydrogen Vehicles

I assume that ethanol vehicles emit as much methane as do methanol vehicles. The one ethanol datum of Table M.1 shows a high methane emission level, but the vehicle (an FFV) was not designed to burn ethanol, and the California Air Resources Board (CARB) is not confident of the result. Because methanol and ethanol are both alcohols and are similar fuels, it is reasonable to expect that they will emit roughly similar amounts of methane.

The CARB tested one dual-fuel LPG vehicle, which emitted about as much methane as the gasoline vehicle (Table M.1). Since LPG contains no methane and, in general, the species profile of hydrocarbon (HC) emissions reflects the HC composition of the fuel; there is no reason to expect LPG vehicles to emit large amounts of methane. On the other hand, because LPG is not similar to methanol, there is no reason to expect that the properties that make alcohol-fuel vehicles emit less methane than gasoline-fuel vehicles would apply to LPGs. Consequently, I assume that LPG vehicles emit as much methane as do gasoline vehicles.

Theoretically, hydrogen vehicles might emit trace amounts of methane from the combustion of lubricating oil. However, the CARB (1989) speciated HC emissions from the lubricating oil of a hydrogen vehicle and did not find any methane. I assume no methane emissions.

TABLE M.2 Methane Emissions from Methanol Vehicles Divided by Methane Emissions from the Same or Similar Gasoline Vehicles

Vehicle Comparison	Fuel Comparison	Reference	Ratio (g/mi)
FFV			
Chevrolet Corsica FFV	M100/M0	Gabele (1989)	0.19-0.26
Ford Escort FFV	M100/M0	Ford (1988)	0.50
Ford Crown Victoria FFV	M100[a]/M0	Ford (1988)	0.88
Ford Crown Victoria FFV	M100/M0	CARB (1989)	0.27
2.5-L GM VFV	M100/M0	Williams et al. (1989)	0.05
Chevrolet Corsica FFV	M85/M0	Gabele (1989)	0.33-0.59
Ford Escort FFV	M85/M0	Ford (1988)	0.70
Ford Crown Victoria FFV	M85[b]/M0	Ford (1988)	1.69
Ford Crown Victoria FFV	M85/M0	CARB (1989)	0.56
Ford Crown Victoria FFV	M85/M0	CARB (June, 1988)	0.40
2.5-L GM VFV	M85/M0	Williams et al. (1989)	0.39
Dedicated vehicles			
1981 Volkswagon Rabbit	M95/gasoline	CARB (1985)	0.33-0.67
1981 Ford Escort	M90-95/gasoline	CARB (1985)	~0.30
1984 Ford Mustang/1983 Ford Escort	M90/gasoline	Gabele et al. (1985)	0.43
1981 Volkswagon Rabbit	M85/gasoline	CARB (1985)	1.00-4.33

[a] At 3,000 mi, from Table M.3.

[b] At 16,000 mi, from Table M.3.

Note: Calculated from the data shown in Tables M.1, M.3, and M.4.

M.2.5 Heavy-Duty Vehicles

The data for heavy-duty vehicles (HDVs) are more scattered. The MOBILE3 and MOBILE4 assumption for heavy-duty diesel vehicles (HDDVs) does not quite agree with the data from the tests reported in Table M.1. Nevertheless, I have used MOBILE4 values.

There also are wide ranges reported for natural gas and methanol HDVs. The range with methanol is so wide, and there are so few data, that it is probably best to assume that methanol HDVs would emit less than HDDVs (just as methanol LDVs will emit less than gasoline LDVs), rather than try to make an estimate based on a few scattered data.

TABLE M.3 Methane and Nitrous Oxide Emissions from Flexible-Fuel Vehicles Tested by Ford

				Emissions (mg/mi)				
Vehicle	Fuel	Miles on Catalyst	Number of Tests	CH_4	N_2O	HCOH	NO_x	NO_x/N_2O
FFV Ford Escort	Indolene	4,000	6	44	116	0	565	4.9
	M50	4,000	2	28	129	24	410	3.2
		50,000	2	23	127	31	890	7.9
	M85	No catalyst	4	34	-2[a]	181	2,735	-1,823.3
		4,000	2	31	105	46	430	4.1
		50,000	4	30	112	53	593	5.3
	M100	No catalyst	2	31	-3[a]	244	2,570	-1,028.0
		4,000	4	22	54	47	353	6.5
		50,000	5	20	123	70	556	4.5
FFV Ford Crown Victoria	Gasoline	12.500	1	42	13	25	753	57.9
	M85	No catalyst	7	68	2	533	1,408	758.4
		0	3	37	7	4	570	77.7
		3,000	3	31	12	19	703	58.6
		16,000	1	71	16	27	840	52.5
		30,000	3	45	18	46	788	43.8
		4,000[b]	3	48	18	92	676	38.3
	M100	No catalyst	5	39	-0.4[a]	676	1,089	-2,723.0
		3,000	7	37	14	33	524	36.7

[a] Vehicle actually consumes net N_2O.

[b] Catalyst was contaminated with oil.

Source: Ford Motor Company, speciated emissions data transmittal (1988).

M.2.6 Aggregate Methane Emissions from a Large Natural-Gas-Fueled Fleet

Although methane emissions from vehicles are a nonnegligible fraction of total CO_2-equivalent emissions from highway vehicles, petroleum-fueled highway vehicles account for a negligible percentage of total methane emissions worldwide. However, NGVs emit considerably more methane than petroleum-fueled vehicles, and one might want to know if an all-NGV fleet would contribute significantly to global methane emissions. I have calculated that even if all vehicles worldwide were fueled by natural gas and emitted relatively large amounts of methane per mile, the global concentration of methane would increase by only a tiny amount (DeLuchi et al., *A Comparative Analysis of Future Transportation Fuels*, 1987). Considering further that it is very difficult to catalyze methane emissions to CO_2 and water (a unit of carbon is less greenhouse

TABLE M.4 Federal Test Procedure (FTP) Methane Emissions from Two Variable-Fuel Vehicles (mg/mi)

	Chevrolet Corsica[a]					
	Percent Methanol/Percent Gasoline					
Temperature (°F)	100/0	85/15	50/50	25/75	0/100	Ratio (M100/M0)
40	NA	41	48	68	82	NA
75	9	20	26	25	34	0.26
90	8	14	26	36	42	0.19
	2.5 L GM VFV[b]					
	Percent Methanol/Percent Gasoline					
	100/0	85/15	50/50	15/85	0/100	Ratio (M100/M0)
	2	14	20	16	36	0.05

[a] From data in Gabele (1989).

[b] From data in Williams et al. (1989).

Note: NA = not available (the car would not start below 60°F on 100% methanol).

effective as CO_2 than as methane, and so from a greenhouse standpoint the transformation of methane to CO_2 is desirable), it probably would not be cost-effective to concentrate on reducing methane emissions from the vehicles.

M.3 Leaks of Methane from Natural Gas Production, Transmission, and Distribution

In a previous, preliminary estimate of greenhouse gases from the use of alternative transportation fuels (DeLuchi et al., *Transportation Fuels and the Greenhouse Effect*, 1987), I assumed that the amount of gas actually leaking from natural gas systems is equal to the amount of gas (between 1 and 3%) that, according to the Energy Information Administration (EIA), is unaccounted for (EIA, *Natural Gas Annual*, annual publication). Other researchers cited numbers of similar magnitude, ranging from 3 to 4% (see Bolle et al., 1986). It now appears that the estimates of 3-4% for the U. S. system are as much as an order of magnitude too high.

It is important to understand that unaccounted-for is not a measure of leakage; it is simply the difference between the sum of the components of natural gas supply and the sum of the components of natural gas disposition. With millions of consumers and a quarter of a million producing wells (and different data-gathering and reporting protocols), it is not particularly surprising that supply does not exactly equal disposition. Thus, unaccounted-for gas has no physical meaning. This is illustrated by the value for 1988: *negative* 0.4% (EIA, *Monthly Energy Review,* April 1989). If a positive value of unaccounted-for gas represents leakage to the atmosphere, then a negative value would have to mean removal from the atmosphere.

However, gas does leak from production, storage, transmission, and distribution systems. In the course of normal operations, gas leaks (or is vented) from instruments that operate on gas, from valves opened to drain liquids from pipelines and, on occasion, from overpressure valves. Gas may be vented from buildings during construction or emitted during the purging of pipelines (AGA, "Natural Gas Transmission and Distribution Methane Emissions," 1989, SS-88-4-1). Intentional venting probably accounts for a minority of losses.

Studies of leakage per se (as opposed to unaccounted-for gas), consistently indicate a loss rate of less than 1% (Table M.5). Recently, the American Gas Association (AGA, "Natural Gas Transmission and Distribution Methane Emissions," 1989) reported the results of a national survey asking natural gas transmission and distribution companies to estimate gas losses in their systems. The respondents indicated a total loss of about 0.34%. The transmission companies claimed to be confident about their estimates; the distribution companies were less confident. (Leaks in high-pressure transmission lines are easier to identify than leaks in low-pressure distribution lines.)

Shortly before this study, the AGA estimated total leakage to be in the range of 0.2-0.3% (AGA, "Natural Gas and Climate Change: The Greenhouse Effect," 1989). Similarly, the Alphatania Group surveyed 41 natural gas companies operating worldwide and found that leakage from transmission and distribution was 43% of throughput (Canadian Gas Association, 1990; Table M.5). They also estimate that leakage from gas production was about 0.20% of throughput.

According to Okken and Kram (1989), gas companies estimate that less than 1% of the gas carried in modern natural gas distribution grids leaks, and that methane emissions from the maintenance and repair of pipelines and compressors in the Netherlands are about 0.005% of the amount of methane transported.

In 1989, the Pacific Gas and Electric Company (PG&E) (Cottengim et al., 1989) completed what it called the "most comprehensive analysis of unaccounted-for gas ever undertaken." The study investigated leakage (both intentional and unintentional), theft, metering inaccuracies, and accounting problems for the PG&E transmission and distribution system in 1987. Intentional losses, such as from purges and valve operations, were determined from historical records and field surveys. Unintentional leaks from distribution systems were estimated for different categories of distribution pipe by field tests of different kinds of leaks. The transmission system was assumed to leak at "the highest conceivable rate." Losses from unintentional ruptures were estimated by multiplying an average (apparently historical) loss rate per

TABLE M.5 Recent Surveys, Studies, or Estimates of the Rate of Leakage of Natural Gas Transmission and Distribution Systems

Organization (Reference)	Natural Gas Lost, Percent of Delivered Natural Gas: Production	Transmission	Distribution	Comments
Canadian Gas Association (1990)	0.25	0.018-0.082	0.03	Estimate for Canadian companies
Alphatania Group (CGA, 1990)[a]	0.20	0.13	0.30	Survey of 41 companies worldwide
AGA (SS-88-4-1, 1989)		0.06	0.28	Survey of U. S. natural gas companies
European gas companies[b]		0.005	<1.00	Higher loss in old distribution lines
Germany (Okken, *Energy Policy,* 1990)		—	0.50	
PG&E (Cottengim et al., 1989)		——— 0.14 ———		Mostly distribution losses[c]

[a] As reported by the Canadian Gas Association (1990); also mentioned in Wilson (1990).

[b] Communication from personnel at gas companies to Okken and Kram (1989).

[c] Unintentional losses from distribution systems were 0.06% of the total; unintentional losses from transmission systems were 0.005%; losses from ruptures of any kind of system were 0.01%; losses from instrument usage, facility blow and purge gas, gas sampling, drip operations, relief valve operations, and miscellaneous operations were 0.065%.

rupture by the number of ruptures in 1987. All told, intentional and unintentional losses amounted to only 0.14% of total deliveries. In fact, losses were only 9% of all unaccounted-for gas; the biggest source of unaccounted-for gas was inaccuracies in orifice meters.

Some gas permeates through the walls of plastic pipes, but the rate, 0.26 ft^3/day-mi (Spriggs, 1988), is insignificant.

Some researchers speculate that leaks from older distribution systems may exceed 1% of transported gas. However, there are no reliable data, not only on leaks from older systems but also on the amount of gas carried in older systems. I suspect that the vast majority of gas is carried in modern systems because most gas is consumed in developed countries. In 1987, the United States, Canada, France, Japan, Italy, West Germany, Britain, the Netherlands, and Japan accounted for nearly half of total global gas consumption, and all of these countries undoubtedly have mostly modern distribution systems. These countries plus the rest of Europe and the

U.S.S.R. accounted for 80% of global consumption. (However, the systems in Eastern Europe and the U.S.S.R. may be leakier than those in the West.) More importantly, *future* systems everywhere in the world will be more like the tightest current systems than the leakiest ones, and we are, in energy policy, interested in the greenhouse consequences of future energy choices. Over the next several decades most (if not nearly all) gas likely to be used by the United States will be transported in systems that, according to preliminary studies, lose much less than 1% of throughput.

Finally, I note that staff at the EIA believe that gas leaks total less than 0.5% of total deliveries (McCarrick, 1990), and that the *International Workshop on Methane Emissions from Natural Gas Systems, Coal Mining, and Waste Management Systems* (1990) has come to essentially the same conclusions as I have stated here.

M.3.1 Venting and Flaring of Natural Gas at Gas-Producing Wells

Data from the U. S. Minerals Management Service (Nixdorff, 1991) indicate that 0.04% of the gas produced from federal offshore gas wells in the Gulf of Mexico is vented or flared. Virtually all of this vented or flared gas is likely to have been flared rather than vented. Similarly, gas companies have estimated that no more than 0.005% of total production is vented (*Options for Reducing Greenhouse Gas Emissions*, 1990). Presumably, vented gas is included in the above estimates of total gas lost from production. Even if vented gas is not included, and so should be added to the above estimates, it would have no effect on the overall results: intentional venting, at 0.001-0.005% of production, is 40-200 times smaller than total gas leakage. It therefore can be ignored.

Data from Nixdorff (1991), and information in *Options for Reducing Greenhouse Gas Emissions* (1990), indicate that 0.01-0.04% of total production is flared. This is about 100 times smaller than the amount of gas used as a process fuel in gas fields. Hence, intentional flaring, which has the same greenhouse effect as burning gas as a process fuel, is completely trivial and well within the uncertainty of the estimate of the amount of gas used as a process fuel. It, too, can be ignored.

M.3.2 Assumptions Used in this Section

The greenhouse model used here disaggregates natural gas losses into losses from production (including gas lifting, gathering, and processing), transmission, and distribution. All three kinds of losses apply to compressed natural gas (CNG) and natural gas users. However, only production and transmission losses apply to methanol from natural gas (and to natural gas power plants), since methanol plants will be located near production fields or large-volume transmission lines. (This gives an advantage to methanol use, since distribution losses, which will not occur with methanol use, are larger than transmission losses.) Also, in the methanol-from-natural-gas case, the leakage rate from gas transmission is less than in the CNG case, because pipelines from remote gas fields to the methanol plants will be shorter than pipelines from U. S. gas fields to U. S. gas end users (see Appendix J).

Production, transmission, and distribution losses can be estimated using the data of Table M.5. However, one could argue that a portion of the gas lost during gas production operations would have leaked anyway, from natural formations, had all the gas been left in the ground (Gold, 1988). Gold says that in some cases production of gas "demonstrably" reduces methane leakage, but he does not estimate the overall effect of producing gas. In my base case, I assume a *net* leakage rate (total leakage from natural gas facilities less the amount that would have leaked had the gas field not been developed) equal to the lower of the estimates of Table M.5.

M.3.3 Natural Gas Leaks from Natural Gas Compressors and Liquefiers

There are no data on the rate of gas leakage (if any) from natural gas compressors. It is likely that the leakage rate is low because high leakage rates would be hazardous and uneconomical. I expect that little or no gas leaks from the CNG-nozzle/vehicle-port interface because the connection is tightly interlocking, and gas does not flow until the nozzle locks into place. I assume that any leakage from CNG stations is small compared with leakage from distribution stations, and can be considered to be subsumed by the estimate for distribution leaks.

Leakage from a properly functioning liquefied natural gas (LNG) station also should be minimal. The LNG dispensers are fully automatic and self-sealing and have a vapor return line that sends vaporized fuel back to the liquefier or gas pipeline. I assume essentially no regular gas leakage from LNG stations.

If an LNG vehicle is idle for one to three weeks, vaporized LNG will begin to be vented from vehicular storage tanks. (The amount of time before venting begins depends on the storage technology; see DeLuchi et al., 1987, *Comparative Analysis of Future Transportation Fuels*, for a brief discussion.) Tanks vent at about 14 g/hour. However, if the vehicle is driven at least once a week (and most vehicles are), the tank will draw off the vaporized LNG and will not vent. Consequently, in the base case for LNG, I assume that very little LNG is lost to boil-off. (See Appendix B for more discussion.)

M.3.4 Composition of Gas Leaks and Its Relevance to Global Warming

Pipeline-quality gas contains CO_2, NMHCs and, of course, methane. These greenhouse gases have different warming potentials per gram, and, consequently, the precise overall warming effect of natural gas leaks depends on the proportions of these individual compounds.

The composition of pipeline gas is discussed in Appendix C and shown in Table C.3. In the calculation of CO_2-equivalent greenhouse gas emissions from natural gas leaks, separate warming factors are assigned to each species (warming factors are derived in Appendix O).

M.3.5 Synthetic Natural Gas Systems

I assume that pipelines delivering medium-Btu synthetic natural gas (SNG) will leak at the same rate as pipelines delivering regular natural gas (Table 5). SNG is composed of hydrogen (H_2), CO_2, CO, methane, and small amounts of NMHCs (Feldmann et al., 1988; Flanigan et al., 1988). The greenhouse effect of leaks of SNG is equal to the CO_2 equivalent of each of the components of SNG, less a CO_2 credit for each mole of carbon emitted, since all of the carbon in SNG originally comes from atmospheric CO_2 via photosynthesis. I assume 20% H_2, 20% CO_2, 40% CO, 13% CH_4, and 7% NMHCs (following Flanigan et al., 1988).

M.4 Vented and Flared Associated Gas from Oil Production

Many fields contain both natural gas and crude oil. Some of these fields contain mostly crude oil and are developed primarily for the sale of the crude. However, the extracting of the crude also produces small amounts of natural gas, and if there is so little of this coproduced (or associated) gas that it cannot be collected and sold economically, it must be disposed of somehow. There are three ways to dispose of unmarketed associated gas: reinject it into the producing field, burn it (called flaring), or simply vent it to the atmosphere. If the gas is reinjected, it never enters the atmosphere and obviously is of no concern in an analysis of emissions of greenhouse gases. However, venting releases the gas in its original state (as mostly methane), and flaring releases it as CO_2. Emissions of methane and CO_2 from venting and flaring of associated gas should be assigned to the use of petroleum fuels, since the emissions result from the extraction of the crude oil.

Several sources, including the United Nations, the Organization of Petroleum Exporting Countries (OPEC), government energy agencies, and major international gas companies, estimate the amount of gas vented and flared locally, regionally, and worldwide. The EIA analyzes the quality of these data and publishes "best estimates" (*International Energy Annual*, 1991, 1982-1989; J. Johnson, 1990). Table M.6 shows the EIA's world total vented and flared gas (a combined figure; venting and flaring are not distinguished) from 1981 to 1988, the latest year for which data are available.

As shown in Table M.6, the quantity of vented and flared gas, and the ratio of vented and flared gas to total oil production generally have been declining. Worldwide, venting and flaring will continue to decline as natural gas increases in value and is reinjected, used domestically, or exported. The United Nations (U.N.) projects that in 2010, the amount of venting and flaring will be half of what it was in 1987 (United Nations, Energy data base, no date). Major gas-producing developing countries are expected to use associated gas to help fuel industrial development (International Energy Agency [IEA], *Energy Policies and Programmes of IEA Countries, 1988 Review*, 1989).

I have assigned venting and flaring to U. S. petroleum use by dividing the amount of gas vented or flared in eight regions of the world by the total crude production in these regions, then multiplying each regional ratio by the amount of that region's crude that the United States

TABLE M.6 Vented or Flared Natural Gas (world totals)

	Year							
	1981	1982	1983	1984	1985	1986	1987	1988
Vented/flared (TCF)	3.87[a]	NA	3.85	3.53	3.08	2.98	2.89	3.20
Reinjected (TCF)	4.08[b]		5.41	5.77	6.33	6.15	7.35	7.46
Dry gas produced (TCF)	54.53		54.45	59.27	62.17	63.25	66.17	69.75
Crude oil produced (mbd)[c]	55.78		52.97	54.20	53.65	55.87	56.31	58.46
Ratio (vented/flared to crude production)	6.94%		7.27%	6.51%	5.74%	5.34%	5.13%	5.47%

[a] The EIA (1983) shows the total as 3.269, with data for the U.S.S.R and other Middle East countries unavailable. In later years, the total for these was around 0.6 TCF. I have added this to the given 3.269 total. All subsequent figures for vented/flared natural gas include the U.S.S.R and other Middle East countries.

[b] This total probably does not include data for the U.S.S.R and other Middle East countries, as above. I did not check.

[c] From EIA, *Annual Energy Review* (1990).

Note: mdb = thousand barrels per day. NA = not available.

Source: From EIA, *International Energy Annual,* issues published from 1983-1991, except as noted.

consumes (directly as crude or indirectly as products). This gives a disaggregated, regionally weighted venting and flaring number for U. S. oil consumption. Table M.7 shows the actual results for 1987 and the projected results for the year 2000. The projected year-2000 results are calculated by applying a reduction factor to the 1987 results; the reduction factor accounts for the expected reduction in venting and flaring in regions that now vent and flare a lot of gas (U.N., no date; ICF, 1990). It is based in part on U.N. projections of venting and flaring in the year 2000 in eight regions of the world and is discussed briefly in the notes to Table M.7.

I assign venting and flaring to the production of crude oil only (and not to crude, gas, and natural gas liquids (NGLs) production jointly) because if a well is venting and flaring a significant amount of gas, it obviously is not marketing gas. If there is enough gas associated with a well to justify gas recovery, the gas and the NGLs will be recovered and little, if any, gas will be flared because the gas is valuable. If there is not enough gas to make recovery worthwhile, then it will be flared and only crude will be produced. (I have assumed that field production of NGLs is associated with the production of natural gas.) In support of this, EIA survey data show that *no* gas was vented and flared from wells that produce only natural gas (EIA, *Natural Gas Annual 1989*, 1990).

Hence, it seems logical to assign venting and flaring to crude production only.

TABLE M.7 Calculation of Weighted Venting and Flaring Emissions from the Average Barrel of Crude Used by the United States

Region[a]	Middle East	North Europe	West Africa	Mediter-ranean	South Pacific	Central America	South America	North America	Total
Vented/flared in region, BCF, 1987[b]	920	94	559	301	337	75	439	235[c]	2,942
Crude production in region, mbd, 1987[d]	23,305	3,626	1,982	3,635	5,445	2,590	3,485	10,630	54,698
SCF-natural gas/bbl-oil, in region, 1987[e]	108.2	71.0	772.7	226.9	169.6	79.3	345.1	60.6	N/A
Year-2000 venting/flaring divided by year-1987 venting/flaring[f]	0.90	1.00	0.50	0.67	0.67	1.00	0.67	1.00	N/A
SCF-NG/bbl-oil, year 2000[g]	97.3	71.0	386.3	158.8	127.2	79.3	231.2	60.6	N/A
To United States									
Crude from region, mb, 1987[h]	359,060	136,455	302,013	62,594	146,499	220,632	256,688	3,269,359	4,753,300
Products from region, mb, 1987[i]	51,969	66,238	12,780	134,557	40,908	140,955	195,692	87,570	730,669
Crude share from region, 1987	0.075	0.029	0.063	0.015	0.031	0.048	0.056	0.682	1

Weighted SCF-natural gas/bbl-oil for crude used by the United States, year 2000: 102.4[j]

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[a] See Appendix H for a listing of countries in the regions.

[b] From EIA, *International Energy Annual* (1989). Data for countries not in the EIA are from the U.N. natural gas data base.

[c] Includes gas vented and flared from U.S. federal offshore oil platforms (see text for discussion.)

TABLE M.7 (Cont.)

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[d] Crude oil only. Calculated as production of oil, which is crude + NGLs + other oils + refinery gain (as reported in the EIA, *International Energy Annual,* 1989), less EIA's reported refinery gain, other oils, and NGLs.

[e] Calculated from the previous two lines.

[f] Projected venting and flaring per barrel in the year 2000 divided by actual venting and flaring in the year 1987. This represents the expected continuing decline in venting and flaring in some regions of the world. Venting and flaring in North America, Central America, and Western Europe is already very low and probably cannot decline further. On the other hand, many of the countries that now vent and flare a lot of gas are trying to reduce the rate. For example, Nigeria, the largest flarer of gas in the world, "has stated policies encouraging alternatives to flaring," including domestic use of the gas and export, and Algeria is planning to increase its reinjection of gas to enhance oil recovery (ICF, *Estimates of the Costs of Collecting Vented and Flared Gas for Alternative Fuel Production*, 1990).

The United Nations has projected venting and flaring emissions in seven regions of the world through the year 2020 (United Nations, no date). The year-2000/year-1987 values used here are based in part on the U.N. projections.

[g] The product of the two previous lines.

[h] From data in the EIA, *Petroleum Supply Annual* (1988).

[i] Calculated as crude from the region plus the crude equivalent of products from the region, divided by the total crude and the total crude equivalents of products. The crude equivalent of products is equal to: volume of products multiplied by the U.S. ratio of refinery crude input to refinery product output. I assume that products from Country X are made from crude oil from Country X, except in the case of products from the Bahamas, U.S. Virgin Islands, Puerto Rico, and Netherlands Antilles. These countries produce no crude, so I assume that the crude comes from Central America.

[j] The crude share multiplied by SCF-natural gas/bbl-oil for each region, summed for all regions.

Notes: mbd = thousand barrels per day. mb = thousand barrels. N/A = not applicable.

M.4.1 Completeness of the EIA Data

The EIA collects venting and flaring data from state agencies in the United States and from foreign governments. The state offices report venting and flaring from *all* onshore oil wells but only *state*, not *federal*, offshore oil wells. To estimate venting and flaring in the United States, the EIA uses only the state data; therefore, the EIA data for the United States do not include venting and flaring from federal offshore oil wells (EIA, Office of Oil and Gas, 1991).

The U. S. Mineral Management Service (MMS) does collect data on venting and flaring from federal offshore oil wells. In 1990, in the Gulf of Mexico, 48 standard cubic feet (SCF)* of gas was vented or flared from oil wells per each barrel of crude oil produced (calculated from total venting and flaring and total production for the Gulf of Mexico, January 1990 to November 1990; transmitted by Nixdorff, 1991). Since production from federal offshore oil wells in the Gulf of Mexico is typically about 90% of total federal offshore oil production (U. S. MMS, 1989), one can assume that this 48-SCF-per-barrel (bbl) rate applied to all federal offshore oil wells in 1990. With this venting and flaring rate and data on total federal offshore production (U. S. MMS, 1989), one can estimate total vented and flared gas for federal offshore oil wells. It amounts to about 15% of the vented and flared gas reported by the EIA.

In Table M.7 I have added the federal offshore venting and flaring, calculated as above, to the total reported by the EIA for 1987.

It is possible (but not likely) that a large amount of associated gas is vented underwater and not reported. Sackett and Barber (1988) state that in the 1970s, it was common to vent natural gas underwater at offshore oil-producing platforms. *Sea Technology* (1974) and Brooks et al. (1977) cite large estimates of vented and flared gas in 1973 and 1974 (about 150 SCF/bbl), and Brooks et al. (1974) argue that most of this was vented underwater. However, the MMS data discussed above show much less venting and flaring in 1990 (48 SCF/bbl). The question, then, is this: Has offshore venting and flaring declined dramatically since the early- to mid-1970s, or are the MMS data incomplete compared with the data sources used in *Sea Technology* (1974) and Brooks et al. (1977)? The answer appears to be the former, because *Sea Technology* (1974) cites the U. S. Department of the Interior (probably the U. S. Geological Survey), and because Brooks et al. (1977) cite personal communications from the U. S. Geological Survey, and the MMS has taken over the venting/flaring-data-collection function from the U. S. Geological Survey (Nixdorff, 1991). The data thus come from the same source and show that venting and flaring have declined. (Note, too, that the MMS data come from oil companies, which are supposed to report *all* venting and flaring.)

In the base case, I assume that the EIA plus the MMS data cover all sources of vented and flared gas.

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* A standard cubic foot of gas is measured at 60°F, 14.73 psia, dry.

The EIA does not know if the sources they use for other countries are incomplete. Since I have no reason to assume that they are seriously incomplete, I make no further adjustments to the EIA data. However, in a scenario analysis, I consider the possibility that data from other countries are incomplete.

M.4.2 Vented versus Flared Gas

To calculate the greenhouse effect of vented and flared gas, the aggregate measure (vented and flared) must be disaggregated to the amount vented (venting releases methane, NMHCs, and CO_2) and the amount flared (flaring produces CO_2). Although none of the reference documents for vented and flared gas (aggregated) estimate the proportion that is vented and the proportion that is flared, it is widely believed that most, if not all vented and flared gas is actually flared. Staff members at the Office of Oil and Gas at the EIA expect that at least 95% of all vented and flared gas is actually flared; the term "vented and flared" is something of an anachronism, dating from a time several years ago when a fair amount of gas really was vented (McCarrick, 1990). In fact, unmarketable, unreinjected associated gas must be flared to destroy toxic compounds in the raw gas and prevent the accumulation of an explosive concentration of natural gas. Generally, gas can be vented only when a very small amount is released in a remote location with strong winds, and these situations are relatively rare.

The EIA staff (McCarrick, 1990) believe that well over 95% of vented and flared gas is flared. However, as mentioned above, Sackett and Barber (1988) and Brooks et al. (1977) believe that in the 1970s, a large fraction of offshore waste gas was vented underwater. Brooks et al. (1977) state that "the [offshore] petroleum industry considers venting preferable" to flaring for several reasons (p. 378), and note that the U. S. Geological Survey estimated that 70% of offshore vented and flared gas actually was vented in 1974. In support of this, Brooks et al. (1977) also found a high concentration of methane and other hydrocarbons in the waters of the Gulf.

There are two possibilities here: either the fraction of vented gas has declined considerably (to 5% or less), as implied by the EIA, or else there is still a large amount of perhaps clandestine venting (more than 50%). I take a middle ground and assume that venting has declined somewhat. In 1987, 21 BCF of gas was vented or flared from offshore oil leases (based on 48-SCF/offshore-bbl, from above, and 437×10^6 bbl produced from state and federal offshore leases, according to the MMS, 1989), and 121 BCF was vented or flared from onshore fields (124-BCF from onshore and state offshore production, as reported by the EIA, minus my estimate of 3-BCF from the offshore state leases). If 2.5% of onshore gas and 25% of offshore gas was vented, then overall about 6% of vented and flared gas was actually vented in the United States in 1987.

To get from the venting fraction applicable to U. S. crude oil production in 1987 to the fraction applicable to production of all crude oil ultimately consumed by the United States in the year 2000, one must know the venting fractions of countries that export crude and products to the United States and the path of the venting fraction over time. I assume that, on the one hand, some oil exporters now vent more than 6% of total vented and flared gas, but that on the other hand, the venting fraction will decline somewhat worldwide, so that by the year 2000, the venting fraction applicable to U. S. consumption will be 6%. I consider a higher percentage in a scenario analysis.

M.4.3 Composition of Vented and Flared Gas and Its Relevance to Global Warming

Raw natural gas contains methane, CO_2, and NMHCs. These greenhouse gases have different warming potentials per gram, and consequently the precise overall warming effect of vented raw natural gas depends on the proportions of these individual compounds in the raw gas.

I have back-calculated the composition of raw natural gas using data on the composition of pipeline gas (reported in Weaver, 1989), the amount of nonhydrocarbon gases removed from raw gas (data given by the EIA, *Natural Gas Annual 1989*, 1989), the composition of nonhydrocarbon gases removed (my assumption), and the amount and composition of natural gas liquids removed from raw gas (data from EIA, *Natural Gas Annual*, 1989). The results are shown in Table C.3. This method produces detailed and mutually consistent estimates of the composition of raw and pipeline gas and allows as precise an estimate as possible of the greenhouse impacts of leaks of pipeline gas and raw gas.

In the calculation of CO_2-equivalent greenhouse gas emissions from vented gas, separate warming factors are assigned to each species (warming factors are derived in Appendix O). I assume that all carbon in flared gas oxidizes to CO_2.

M.4.4 Assignment of Venting and Flaring Emissions to Products

The result of the calculation of Table M.7 is a weighted value (in SCF of natural gas per barrel) of oil used by the United States. This number has to be converted to SCF of gas per 10^6 Btu of each product made available to end users. I do this with the following formula:

$$VF_p = O_p \times D_p/Dc \times VFc \times H_p$$

where:

VF_p = SCF of gas vented or flared per 10^6 Btu of product (p) available to end users;

O_p = own-use factor for product (p) (see appendix on general methods);

D_p = density of product (p) (Table C.1);

Dc = density of crude oil (Table C.1);

VFc = SCF of gas vented or flared per bbl of crude used by the United States (weighted average) (Table M.7); and

H_p = volumetric heating value of product(p) (EIA data; Table C.1).

M.5 Methane Emissions from Coal Mining

M.5.1 Overview

The processes that produce coal, called coalification, also produce methane. Some of the methane produced is stored in the coal bed. However, coalification produces much more methane than the coal can store. This excess methane migrates into the surrounding rock and sand strata, forming the traditional natural gas deposits mined by the natural gas industry. The formation of a ton of anthracite may generate 6,000 ft^3 of methane (Ayers and Kelso, 1989).

When coal is mined, methane seeps out of the coal and into the mine. To prevent the accumulation of a hazardous concentration of methane, the gas is mixed with air and vented to the atmosphere or, in a few instances, collected at the face, drained, and used as a fuel.

The rate of methane emission from coal mines depends on the age, depth, and structure of the coal bed; the mining technique; the rank and quality of the coal; and other factors. Emissions increase with the depth of the mine and the rank of the coal; the higher the fixed carbon content of the coal, the higher the methane content (Deul and Kim, 1988; Kuuskraa and Brandenburg, 1989). In room-and-pillar mining, methane comes from the recovered coal, the support structures, surrounding coal beds, and unmineable coal seams. In longwall mining, methane is emitted from mined coal, unmineable seams, and from the strata that collapse when the supports are removed. In surface mining, methane is emitted from mined and exposed coal and from adjacent seams.

Most of the methane in mined coal is released by the pressure drop as a result of the coal being exposed to atmospheric pressure. Most of the remaining methane is released when the coal is cleaned, crushed, and prepared for final use. A small amount of methane remains in the prepared coal and is burned with the coal.

Some coal-bed methane can be recovered and used as a fuel before the bed is mined for coal. U. S. coal beds contain about 400 trillion cubic feet (TCF) of methane, of which 90 TCF are recoverable (Ayers and Kelso, 1989; H.T. Black, 1990). Coal-bed methane research and development has grown considerably in recent years, and several large methane recovery projects are operating, almost ready to operate, or planned (Ayers and Kelso, 1989; Kuuskraa and Brandenburg, 1989; Schraufnagel et al., 1990). In 1988, 28 billion cubic feet (BCF) of methane were recovered from coal beds, mostly in Alabama, Colorado, and New Mexico (EIA, *Natural Gas Annual 1989*, 1989). Kuuskraa and Brandenburg (1989) project that by the early 1990s, this amount will increase to 365 BCF/yr.

Still, several obstacles to the large-scale development of coal-bed methane remain, including the difficulty of finding highly permeable, productive spots in coal fields; the high costs of gas recovery; the environmental impacts of disposing of coproduced water; and the reluctance of coal companies to get involved (Schraufnagel et al., 1990).

M.5.2 Estimating Methane Emissions from Coal Mining

Until quite recently, there has been no detailed estimate of methane emissions from coal mining. In a much-cited chapter of a book on climate change, Bolle et al. (1986) make a table of several estimates of methane emissions from coal mining, including estimates by Crutzen and Gidel (1983) and Rasmussen and Khalil (1984). These and other sources cited in Bolle et al. (1986) take their numbers from articles by Ehhalt and Schmidt (1978) and Ehhalt (1974). These two authors, in turn, refer to a National Aeronautics and Space Administration (NASA) study by Hitchcock and Weschler (1972). This NASA report uses an estimate from Koyama (1963). Koyama's estimate appears to be original. However, Koyama was concerned mainly with methane from paddy fields; he estimates methane emissions from coal mining in a one-sentence calculation in which he assumes coal fields produce methane at a rate of 21 cm^3/g of coal produced (p. 3973). This unreferenced, unelaborated, 1963 assumption has been propagated through the literature for many years.

A more accurate estimate is needed. I have compiled estimates of methane emissions from all coal mining and methane emissions from underground mining, and I have compiled estimates of and calculated the methane content of coal. The results and details of my calculations are shown in Table M.8. Although the value of ultimate interest is that for methane emissions from all mining, it is useful to examine, in addition, methane emissions from underground mining alone and the methane content of coal, because the three values are related.

The order of the magnitudes of the three values of emissions from all mining, emissions from underground mining, and the methane content of coal are as one would expect (Table M.8). The emission rate from underground mines should be, and is, greater than the all-mines average, since surface mines emit less methane per ton produced than do underground mines. (Generally, methane content increases with depth.) The emission rate from a mine per ton of coal mined should be greater than the methane content of a ton of mined coal because the face and cracks of the mined surface, as well as the mined material, emit methane. The emission rate from a mine declines over time as faces that have already emitted some of their methane are mined, but the lifetime-average emission rate from a mine (total methane emitted/total coal produced) will still exceed the methane content of the coal because, when the mine is abandoned, the remaining coal will be depleted in methane. (It will have less methane, on average, than it did before mining.) When a mine is abandoned, a considerable amount of coal remains — coal that was either part of the superstructure of the mine or unmineable. However, most of the methane in that remaining coal has been desorbed because of the lower pressures (due to the removal of coal, overburden, and methane). Thus, nearly all of the methane is released from a coal field, but only a portion of the coal is recovered. The result is that the amount of methane released per unit of mined coal should be considerably higher than the amount of methane contained per unit of coal in place. (One factor works against this: a portion of the adsorbed methane never desorbs from the coal, even when the coal is mined and crushed, and so ends up being burned to CO_2 rather than being released as methane; however, the amount is small.)