Section 4
Parametric Assumptions and Their Data Sources

Section 3 presented the general methodologies that are used in GREET. Calculations of fuel-cycle energy use and emissions require researchers to make parametric assumptions for each fuel cycle regarding the following: energy efficiencies of upstream stages (which determine the amount of process fuels and feedstock fuels needed), shares of process fuels, shares of combustion technologies for a given process fuel, and emission rates of a given combustion technology burning a given fuel. This section presents detailed assumptions and data sources for each of these parameters. Combustion emission factors for most fuels and combustion technologies were derived from EPA's AP-42 document (EPA 1995). Combustion emission factors in GREET were updated periodically. The most recent update was done in March 1999. Appendix A (Volume 2) presents combustion emission rates contained in the GREET model.

4.1 Petroleum-Based Fuel Cycles

The GREET model includes six petroleum-based fuel cycles: petroleum to CG, RFG, CD (low-sulfur content), RFD, LPG, and electricity via residual oil. GREET includes both federal and California RFG.

Of the different gasoline types, CG, gasohol (or E10, which is 90% gasoline and 10% ethanol by volume), oxygenated fuel (oxyfuel), and RFG are currently sold in the U.S. gasoline market. Gasohol and oxyfuel, both with high oxygen content, help reduce motor vehicle CO emissions in winter. RFG helps reduce air toxics and ozone precursors in summer. The 1990 Clean Air Act Amendments (CAAA) required nine U.S. metropolitan areas with the worst ozone problems (Los Angeles, San Diego, Chicago, Houston, Milwaukee, Baltimore, Philadelphia, Hartford, and New York City) to introduce Phase I RFG beginning in 1995. EPA allows states to opt in to the RFG program; 11 states have done so. Use of a more stringent RFG — Phase 2 RFG — will be required beginning in 2000. Phase 2 RFG is required to reduce VOC emissions by 26% in northern areas and by 27.5% in southern areas, air toxics by 20%, and NO_x by 3%, all relative to a CG with an RVP (Reid vapor pressure) of 7.8 pounds per square inch (psi) (EPA 1994).

Separately, California began to introduce its own Phase 2 RFG in March 1996. In terms of emission performance, California's Phase 2 reformulated gasoline (CARFG2) is more stringent than federal Phase 2 reformulated gasoline (FRFG2). Table 4.1 presents specifications of conventional and reformulated gasolines.

The 1990 CAAA required that low-sulfur diesel with a sulfur content of less than 500 parts per million (ppm) be introduced into the U.S. diesel market beginning in October 1993. Recently, compression-ignition, direct-injection (CIDI) engines have been promoted to improve the fuel economy of passenger cars. CIDI engines fueled with diesel would face a major challenge in

Table 4.1 Specifications of Conventional and Reformulated Gasoline[a]

	CG			Oxygenated Fuel (2.7 wt% O_2)	Phase 1 RFG	
Parameter	Average[b]	Range[c]	Gasohol Average	Average	Average	CARFG2[d] Average
RVP: summer	8.7	6.9-15.1	9.7	8.7	7.2/8.1	6.8
RVP: winter	11.5	NA[e]	11.5	11.5	11.5	NA
T50 (°F)[f]	207	141-251	202	205	202	200
T90 (°F)[f]	332	286-369	316	318	316	290
Aromatics (vol%)	28.6	6.1-52.2	23.9	25.8	23.4	22
Olefins (vol%)	10.8	0.4-29.9	8.7	8.5	8.2	4
Benzene (vol%)	1.6	0.1-5.18	1.6	1.6	1.0 (1.3 max)	0.8
Sulfur (ppmw)	338	10-1170	305	313	302 (500 max)	30
MTBE[g]	NA	0.1-13.8	NA	15	11 (7.8-15)	Unknown[h]
EtOH (ethanol)[g]	NA	0.1-10.4	10	7.7	5.7 (4.3-10)	NA

[a] From the Web site of EPA's Office of Mobile Sources (1998).

[b] As specified in the 1990 CAAA.

[c] From a survey conducted by the Motor Vehicle Manufacturers Association in 1990 as cited by EPA (1998d).

[d] CARFG2 specifications are from CARB (1996).

[e] NA = not available or not applicable.

[f] T50 = the temperature at which 50% of gasoline is vaporized; T90 = the temperature at which 90% of gasoline is vaporized.

[g] Oxygenate concentrations shown are for separate batches of fuel; combinations of both MTBE and ethanol in the same blend can never be above 15% total (by volume).

[h] Until March 1999, California allowed only MTBE to be used to meet the oxygen requirement of 2% by weight. Because of concern about contamination of water with MTBE, California Governor Gray Davis announced in April 1999 that the use of MTBE in CARFG2 will be phased out by the end of 2002.

meeting the Tier 2 vehicle NO_x standard (0.07 g/mi) and PM standard (0.01 g/mi) proposed by EPA (EPA 1999). To meet the standards, diesel fuel used in the CIDI engines must be reformulated to reduce its sulfur and aromatics content. At present, no one knows the exact specifications that would be required for an RFD, although researchers generally agree that the sulfur content could be as low as the sulfur content of gasoline.

LPG, primarily propane, is produced from petroleum refineries and NG liquid plants. In the United States, about 40% to 50% of LPG is produced from petroleum refineries, and the remaining 50% to 60% from NG liquid plants. A large number of LPG vehicles are in use in this country. In fact, LPG vehicles account for the largest share of U.S. AFVs.

Residual oil, produced in petroleum refineries, is used in home heating, barges, and oil-fired electric power plants. GREET includes oil-fired electric power plants, so the crude-to-residual oil cycle is needed in GREET.

Beginning in 1994, U.S. imported crude oil exceeded domestic production. Of the total amount of crude oil that the United States uses for producing petroleum products, more than half is purchased from other countries and transported here. Table 4.2 shows the domestic production and foreign importation of crude oil and its products. As the table shows, while more crude oil is imported than domestically produced, most of the total volume of petroleum products consumed in the United States is produced domestically. In estimating fuel-cycle energy use and emissions, our study (as well as many similar studies) uses input data drawn primarily from U.S. production statistics. While this does not pose a problem for estimating energy use and emissions associated with producing petroleum products in the United States, it does pose a problem for estimating energy use and emissions for the crude oil used. While advanced technologies have made U.S. crude production more energy efficient and have reduced emissions compared to past levels, U.S. production still requires a high level of effort for deep well drilling and enhanced oil recovery — resulting in high energy use and emissions per barrel (bbl) of oil produced. It may be sufficient, then, to use U.S. data to calculate energy use and emissions from global crude production for U.S. consumption. Importation of crude oil certainly increases energy use and emissions during crude transportation from a foreign country to the United States. Most studies consider the additional energy and emissions from cross-continent and cross-nation transportation in calculating energy use and emissions.

4.1.1 Petroleum Recovery

The crude recovery stage of the petroleum fuel cycle includes well drilling, oil extraction, oil gathering through gathering pipes, crude treatment in production fields, and crude storage in production fields. Oil can be extracted by using conventional extraction methods, which rely on the natural pressure of underground oil reservoirs; artificial lift methods (such as surface or subsurface pumps); or enhanced oil recovery methods, which are often used to modify thick, highly viscous crude before it can be extracted from the ground. Three general enhanced oil recovery methods can be used: thermal recovery, chemical flooding, and gas displacement. With the thermal recovery method, steam, which is generated by burning crude, residual oil, and/or natural gas, is injected into an underground crude reservoir. The chemical flooding method involves injecting a mixture of chemicals and water into a reservoir in order to generate a fluid. For the gas displacement method, gases (mainly CO_2) are injected into a reservoir to sweep crude toward a production well. Use of enhanced oil recovery methods can significantly increase the energy required for crude recovery.

Table 4.2 1996 Domestic Production and Importation of Crude Oil and Its Products[a]

	Crude	Gasoline	Diesel Fuel	Residual Oil	Jet Fuel	Propane[b]
Domestic production	6.465	7.647	3.316	0.726	1.515	1.044
Net import	7.398	0.232	0.040	0.146	0.063	0.091

[a] From EIA (1997b). Values are in million barrels per day (10^6 bbl/d).

[b] LPG includes ethane/ethylene, propane/propylene, normal butane/butylene, and isobutane/isobutylene. The numbers presented in this table are for propane, which is the predominant constituent of motor fuel LPG.

Crude oil is brought to the surface with a mixture of oil, water, and gas, which must be separated from the crude in on-site treatment facilities before the crude can be put through pipelines. On-site treatment facilities usually include oil/gas separators, oil/water separators (often called heater treaters), oil storage tanks, and produced water reservoirs.

Energy consumed during the petroleum recovery stage is implicitly contained in the energy efficiency assumptions made for crude recovery. On the basis of existing studies, GREET assumes an energy efficiency of 98% for petroleum recovery (see Table 4.3). Shares of various process fuels are presented in Table 4.4.

Table 4.3 Energy Efficiencies of Petroleum-Based Fuel-Cycle Stages (%)

Petroleum-Based Fuel-Cycle Stage	GREET	NREL et al. 1991	Delucchi 1991	Ecotraffic, AB 1992	Bentley et al. 1992	Acurex 1995
Crude recovery	98.0	99.2	97.5	97.0	NE	NE
Crude T&S	99.5	96.2	99.8	99.3	96.0	NE
CG refining	85.0	NE	NE	84.5	90.0	NE
CG T&S&D	98.5	NE	NE	NE	NE	NE
FRFG2 HC refining[a]	86.0	90.0	81.7	NE	NE	NE
CARFG2 HC refining[a]	85.0	NE	NE	NE	NE	82.8
RFG T&S&D	98.5	97.7	99.2	98.6	98.0	NE
LPG refining	93.5[b]	NE[c]	94.6	90.0	NE	93.2
LPG T&S&D	97.9[d]	NE	99.0	97.5	NE	NE
Residual refining	95.0[b]	NE	94.9	97.0	NE	NE
Residual T&S&D	99.0[d]	NE	99.0	NE	NE	NE
CD refining	89.0[b]	NE	93.0	NE	NE	NE
CD T&S&D	98.6[d]	NE	99.1	NE	NE	NE
RFD refining	87.0	NE	NE	NE	NE	NE
RFD T&S&D	98.6[d]	NE	NE	NE	NE	NE

[a] In order to meet the oxygen requirements of RFG, oxygenates such as methyl tertiary butyl ether (MTBE), ethyl tertiary butyl ether (ETBE), tertiary amyl methyl ether (TAME), or ethanol can be blended into gasoline. Refining efficiencies listed here for RFG HC are for production of the hydrocarbon portion of the RFG in refineries. Energy use and emissions of oxygenate production are calculated separately in GREET. Oxygenates have high octane numbers. Because of the so-called octane enhancement effect by oxygenates, some researchers expect that production of the HC portion of RFG may not be subject to an energy efficiency penalty relative to CG production. The efficiency assumptions here reflect that expectation.

[b] On the basis of the refining intensity involved in generating each product, the GREET model assumes that the order of refinery efficiency (from low to high) is RFG, CG, RFD, CD, LPG, and residual oil.

[c] NE = not estimated.

[d] Primarily on the basis of the energy content per gallon of each fuel, the GREET model assumes that the order of T&S&D efficiency (from low to high) is LPG, RFG, CG, RFD, CD, and residual oil. Besides the energy content of each fuel, transportation distance and length of storage time affect the T&S&D efficiency of each product. While efficiency values for CG and residual oil are simply assumed, the efficiency values for LPG, RFG, CD, and RFD are calculated by using the efficiency of CG and the energy content of LPG, RFG, CD, and RFD.

Table 4.44 Fuel Economy Changes of 1999 MY Alternative-Fuel Vehicle Models[a,b]

	FUDS Cycle (%)	Highway Cycle (%)	55/45 Cycle (%)
Ethanol Vehicles			
Chrysler Caravan 3.3-L (L4)	1	5	3
Ford Ranger 3.0-L (L4, 4WD)	3	-2	1
Ford Ranger 3.0-L (M5, 4WD)	7	2	5
Ford Ranger 3.0-L (L4, 2WD)	-1	2	0
Ford Ranger 3.0-L (M5, 2WD)	7	3	5
Ford Taurus 3.0-L (L4)	3	0	2
CNG Vehicles			
Ford Contour 2.0-L (L4, bi-fuel)	-26	-26	-26
Ford Crown Victoria 4.6-L (L4)	-18	-17	-18
Ford F-250 Pickup 5.4-L (L4)	-15	-12	-14
Ford E-250 Van 5.4-L (L4, bi-fuel)	-15	-17	-16

[a] Based on data contained in DOE and EPA 1998a.

[b] Fuel economy changes by AFVs are relative to fuel economy of comparable gasoline vehicle models. L4 = automatic lockup 4-speed, M5 = manual 5-speed, 4WD = 4-wheel drive, 2WD = 2-wheel drive.

meet federal Tier 1 emissions standards. In Table 4.45, emission reductions by RFG2 are based on emission performance of California RFG2. Fuel economy and emission changes for bi-fuel and dedicated CNGVs rely on testing results of recently introduced vehicle models. FFVs fueled with M85, E85, and LPG are generally assumed to have emissions similar to those of vehicles fueled by RFG2. The fuel economy and performance of HEVs powered by grid electricity are assumed to be the same as the fuel economy and performance of battery-powered EVs. Emissions performance of HEVs powered by on-board engines is assumed to be similar to that of vehicles fueled by RFG2. The emissions performance of diesel-engine vehicles is assumed to be similar across vehicle types.

For the long-term technology options, baseline GVs fueled with RFG2 are assumed to meet the proposed federal Tier 2 standards. Few data are available for long-term technology options. Through our research, we sought inputs from experts on these technology options. The assumptions made here reflect expert opinions together with our understanding of the potential of each technology option. So the assumptions for long-term technology options are more speculative than those for near-term technology options. In general, we assume that long-term technologies will be able to meet the newly proposed Tier 2 standards. If a technology has inherently low emission potential, we assume emission reductions relative to Tier 2 standards.

Few data on the fuel economy of long-term technology options are available. Recently, Stodolsky et al. (1999) completed a study on advanced vehicle technologies. The study was widely reviewed. Fuel economy changes for SIDI vehicles, SIDI HEVs, CIDI vehicles, CIDI HEVs, and FCVs in this study are derived primarily from the Stodolsky study.

Table 4.46 presents fuel economy and emission changes for LDT2. In most cases, fuel economy and emission changes are the same as those for passenger cars and LDT1. In a few

CH_4 emissions are also generated from activities associated with oil extraction and separation. EIA estimates that between 1992 and 1996, annual average CH_4 emissions were 0.04×10^6 metric tons for oil well operations; 0.85×10^6 metric tons for gathering pipelines; and 0.18×10^6 metric tons for heaters, separators, and dehydrators (EIA 1997a). The EIA-reported estimates are for oil and gas production together. When the energy split of oil and NG production from U.S. oil wells is used, we allocate 70% of the emissions from oil well operations to oil production. Emissions from gathering pipelines include those from crude- and NG-gathering pipelines. Because the majority of the emissions are likely to be from gas-gathering pipelines, we allocate 90% of the emissions to gas-gathering pipelines. Heaters, separators, and dehydrators are primarily for crude oil separation, so we allocate 90% of the emissions from these equipment items to crude oil. In summary, CH_4 is emitted from oil wells; gathering pipelines; and heaters, separators, and dehydrators for crude oil production at a rate of 0.275×10^6 metric tons per year ($0.04 \times 70\% + 0.85 \times 10\% + 0.18 \times 90\%$). Using the annual value for U.S. crude production between 1992 and 1996, we estimate a CH_4 emission rate of 20.33 g/10^6 Btu of crude produced. This emission rate includes CH_4 emissions from fuel combustion in the oil field, which GREET calculates separately. To avoid double-counting, GREET-calculated combustion CH_4 emissions for crude recovery are subtracted from this emission rate.

EIA estimated that between 1992 and 1996, 235.7×10^9 ft^3 of NG were vented and flared from oil and gas production (EIA 1997c) — about 4.524×10^6 metric tons of NG. Subtracting the amount of NG vented from oil and gas production (0.93×10^6 metric tons), the amount of NG flared is estimated to be about 3.594×10^6 metric tons. A study conducted for GRI (Energy International, Inc. 1994) estimated that about 87.3% of total flared gas results from oil production in the United States. In GREET, we allocate 85% of the total NG flared to oil production. Although, again, oil wells produce both crude and gas, we allocate all of the NG flared to crude production because it is reasonable not to expect that the wells that produced both oil and gas would flare gas. When the annual crude production rate of 13.53×10^{15} Btu between 1992 and 1996 is used, we estimate that NG was flared at a rate of 225.8 g/10^6 Btu of crude produced, or 10,500 Btu of NG flared per 10^6 Btu of crude produced. This amount was considered, in addition to the amount of process fuels, in calculating combustion-related emissions (in this sense, NG flaring is considered combustion). We use NG combustion emission factors to calculate the amount of emissions generated for the amount of NG flared. We increase the estimated value for U.S. production by 60% to account for high rates of flared gas for imported oil.

VOC Emissions from Evaporation and Spillage. Delucchi et al. (1992) estimated VOC evaporative emissions of 0.009 g/10^6 Btu of crude produced during oil drilling, 0.197 g/10^6 Btu produced during treatment in the oil fields, and 0.496 g/10^6 Btu generated during storage in the oil fields. On the basis of these estimates, the GREET model assumes a VOC evaporative emission rate of 0.702 g/10^6 Btu of crude produced for the crude recovery stage of the fuel cycle.

4.1.2 Crude Transportation and Storage

This stage includes transportation of crude from oil fields to central storage terminals, storage at the terminals, transportation from the terminals to petroleum refineries, and storage at refineries. Crude is transported from oil fields to central storage terminals for segregation, batching, blending, and accumulation of inventory necessary for mass-scale, long-distance transportation. Small-size pipelines and tank trucks are used for the transportation. Central storage terminals are usually located at major water ports or at the beginning of long-distance pipelines. Crude is transported from the terminals to petroleum refineries via ocean tankers (for intercontinent transportation) and/or pipelines (for intracontinent transportation).

Major energy-consuming sources for this stage are ocean tankers and engines that provide pumping and heating for pipelines. Residual oil or bunker fuel is primarily used to provide energy for transportation of crude. Mainly because of the bulk transportation of crude, energy consumption during this stage is usually minimal. On the basis of existing studies, an energy efficiency of 99.5% is assumed for this stage (Table 4.3). Process fuel shares for the T&S stage are presented in Table 4.4.

VOC Emissions from Evaporation. Evaporative VOC emissions are generated during loading, unloading, and breathing of ocean tankers and storage terminals. Delucchi et al. (1992) estimated VOC evaporative emissions of 0.162 g/10^6 Btu for crude handled during loading to vessels and for vessels in transit, and 1.372 g/10^6 Btu for crude storage at refineries. On the basis of these estimates, the GREET model assumes a VOC evaporative emission rate of 1.534 g/10^6 Btu for crude T&S.

4.1.3 Crude Refining

As of January 1998, 163 refineries with a total capacity of 15.9×10^6 bbl of crude input per day (*Oil and Gas Journal* 1997) were operating in the United States. Although U.S. petroleum refineries are located all over the country, 42% of the total U.S. refining capacity is in three states: Texas, Louisiana, and California. The size of U.S. refineries ranges from as small as 5×10^3 bbl/d to as large as 450×10^3 bbl/d.

Petroleum refineries produce petroleum-based fuels and petrochemicals. Table 4.5 presents 1996 U.S. refining products. One of the questions facing researchers who conduct fuel-cycle analyses is how to allocate energy use and emissions from a refinery among all its products. Ideally, a linear programming model for refining processes can be run to simulate production of different refining products. The results of modeling fuel and feedstock usage can be used to calculate the energy use and emissions associated with producing a given product. Because use of a linear program model requires a large commitment of resources, past fuel-cycle analyses have relied on the results of linear programming modeling from other studies. Linear programming modeling studies can usually determine the amount of feedstock and fuels needed to produce a slate of refining products. The

Table 4.5 1996 U.S. Refining Product Outputs

Product Category	Amount (10^6 bbl/d)
Finished motor gasoline	7.647
Distillate fuel oils	3.316
Residual fuel oils	0.726
Jet fuels	1.515
Liquefied petroleum gas	2.156
Others	3.108
Total	18.468

Source: EIA (1997b).

feedstocks and fuels can then be allocated among different products according to the mass of each product and the refining processes necessary for its production. On the basis of this information, fuel-cycle analyses can then be used to determine the refining energy efficiency for producing a given product. The energy use associated with producing that product can then be calculated by using the efficiency value. Noncombustion emissions for refineries can be allocated according to energy use intensity in refineries for each product. This is the approach that GREET takes.

To precisely simulate energy use and emissions associated with producing a given product at refineries, *total* energy use and emissions are estimated for the refinery. The totals are then allocated to different products according to the refining processes necessary for each. This precise approach may be incorporated into a new revision of the GREET model in the future.

Table 4.3 presents the refining energy efficiencies for various products. As the table shows, refining efficiencies are in the following order (from low to high): CARFG2 HC, CG, FRFG2 HC, RFD, CD, LPG, and residual oil. The reason the refining efficiency for FRFG2 HC is higher than that for CG is the octane enhancement effect of oxygenates in RFG. Because of the high octane number of oxygenates, their use in RFG (to meet RFG oxygen requirements) allows use of refinery hydrocarbons with lower octane numbers in RFG. However, production of oxygenates requires a significant amount of energy (both to produce the raw materials such as methanol and ethanol and to produce oxygenates from the raw materials). Overall, considering the energy use and emissions of both the RFG HC portion and RFG oxygenates, production of RFG requires higher energy use and generates more emissions than does production of CG.

Noncombustion Emissions at Refineries. Emissions from combustion of process fuels at refineries are calculated by using the methods described in Section 3. Emissions are also produced by noncombustion processes such as crude cracking (both thermal and catalytic), hydrocarbon reforming, catalyst regeneration, sulfur recovery, and blowdown systems. Fugitive emissions are also generated during various refining processes. Because of a lack of data, emissions from sulfur recovery plants and water treatment plants in refineries are ignored here. On the basis of EPA’s AP-42 document (EPA 1995), we estimated the following noncombustion emissions at refineries: 0.998 g VOCs, 0.358 g CO, 4.260 g NO_x, 1.429 g PM_{10}, 6.481 g SO_x, and 1,172 g CO_2 for each 10^6 Btu of CG produced. For RFG, CD, RFD, LPG, and residual oil, we assumed that noncombustion emissions are proportional to the energy usage intensity of the refining processes involved in producing each fuel. Thus, the noncombustion emission rates for each of these five fuels are obtained by adjusting the noncombustion emission rate of CG by the difference in energy intensity between CG and these fuels.

4.1.4 Production of Oxygenates

Oxygenates such as MTBE, TAME, ETBE, or ethanol can be used in gasoline to meet oxygen requirements for RFG. Because these oxygenates have high octane numbers, their use helps gasoline maintain a high octane number (see Table 4.6). In fact, MTBE has been added to CG to maintain a high octane number since the use of lead in gasoline was phased out in the

Table 4.6 Properties of Four Oxygenates

	MTBE	TAME	ETBE	EtOH
O_2 content (% weight)	18.2	15.7	15.7	34.8
Carbon content (% weight)	68.1	70.6	70.6	52.2
Low heating value (Btu/gal)	93,500	100,900	96,900	76,000
Octane number[a]	98–105	98–103	95–104	100–106

[a] These numbers are motor octane numbers, which are lower than research octane numbers. The range reflects different blending methods.

1980s. Stork and Singh (1995) estimated that on average, CG produced in the United States contains 2% MBTE by volume.

MTBE is manufactured through a reaction of methanol with isobutylene, a NG-based petrochemical. TAME and ETBE are produced in a similar way — methanol reacts with isoamylene to produce TAME, and ethanol reacts with isobutylene to produce ETBE. At present, the U.S. market for RFG is met by MTBE and ethanol, both because MTBE is less expensive to produce than TAME and ETBE (in terms of production costs and feedstock costs) and because ethanol is readily available. MTBE claims almost 90% of the RFG market, and ethanol takes the remaining market (primarily in the Chicago and Milwaukee areas). Blending ethanol into gasoline increases gasoline's RVP (resulting in high evaporative emissions), which could pose a challenge for RFG in meeting gasoline RVP requirements.

In 1998, the United States produced about 75 million barrels and imported 31 million barrels of MTBE for gasoline use (EIA 1999). This 106 million barrels represents about 3.5% of total U.S. gasoline consumption. MTBE production and importation has increased dramatically in the last several years because of oxygen requirements for RFG. Recently, California Governor Grey Davis announced that California will phase out the use of MTBE in gasoline by the end of 2002 because of concerns about water contamination associated with MTBE. It is not clear yet which of the other three oxygenates will be used in California or whether the oxygen requirement for RFG will be abandoned completely in that state. In August 1999, EPA began to discuss the possibility of a nationwide MTBE ban. Continued use of MBTE in gasoline in the United States is not certain, even though it is still the predominant oxygenate.

The GREET model is designed to use any of the four oxygenates in RFG to meet RFG's oxygen requirements. GREET users can determine an oxygen level and select one of the four oxygenates. The model takes into account energy use and emissions associated with feedstock production (methanol for MTBE and TAME and ethanol for ETBE and ethanol) and energy use and emissions associated with production of MBTE, TAME, and ETBE. Production of ethanol is discussed in Section 4.3 and simulated in a different sheet of the GREET model.

On the basis of data presented in Stork and Singh (1995) and Kadam et al. (1998), we estimated energy and feed input for production of MTBE, TAME, and ETBE. Table 4.7 presents our estimates.

Table 4.7 Energy and Material Inputs for Production of MTBE, TAME, and ETBE[a]

	MTBE	TAME	ETBE
MeOH (ton)	0.332	0.332	
EtOH (ton)			0.409
Isobutylene (ton)	0.633	0.633	0.533
Steam (Btu)	1,678,040	1,678,040	1,678,040
Electricity (kWh)	36.81	36.81	36.81

[a] Values are per ton of product.

The three ethers can be produced offsite from petroleum refineries or onsite. Using information presented in Stork and Singh (1995) for RFG, we assume that 99.5% of the ethers are produced from offsite facilities and 0.5% from onsite facilities. The split was calculated as follows. According to EIA (1997b), MTBE input to crude refineries (from offsite facilities) was 79.4 million barrels in 1996. Methanol input was 126,000 barrels. Assuming that the methanol is used for MTBE production onsite and that each ton of methanol produces three tons of MTBE, 378,000 barrels of MTBE were produced onsite. So, the MTBE input to refineries (79.4 million barrels) represents 99.5% of the total MTBE consumed in refineries (79.4 million barrels plus 378,000 barrels).

For use of CG, we assume that 95% of the ethers are produced from offsite facilities and 5% from onsite facilities. This split is calculated as follows. According to EIA (1994), U.S. refineries did not produce RFG in 1993. All motor gasoline produced was CG. In that year, 49.4 million barrels of MTBE were input into refineries (from offsite facilities); 782,000 barrels of methanol were input into U.S. refineries to produce 2.346 million barrels of MBTE onsite. Thus, 95.5% of MTBE consumed in refineries was input and 4.5% was produced onsite.

Isobutylene, a constituent of liquefied petroleum gas, can be produced from petroleum in crude refineries or from NG in NG processing plants. In the United States, 94.5% of isobutylene is produced from NG processing plants and the remaining 5.5% from crude refineries (EIA 1997b). According to EIA (1997b), 4.058 million barrels of isobutylene used in refineries were produced within petroleum refineries and 49.305 million barrels were inputted to refineries in 1996. That is, 7.6% of isobutylene used in refineries was produced in the refineries and 92.4% was produced outside the refineries. We used this split for the isobutylene required for onsite production of ethers. For offsite production of ethers, we assume that the required isobutylene is produced in NG processing plants.

A large amount of steam is consumed during ether production. To estimate energy use and emissions, we assume that steam boilers (with an energy efficiency of 80%) are used for steam generation. For offsite ether production, we assume that NG is used for steam generation. For onsite ether production, we assume that 50% of fuel input for steam generation is from NG and the remaining 50% is from petroleum-derived fuels such as still gas in refineries.

Ethers produced outside (offsite) of petroleum refineries need to be transported to the refineries. EIA's *Petroleum Supply Annual* (EIA 1997b) provides data on total volumes of gasoline blending components moved through pipelines and by tankers and barges. On the basis of the 1996 data (EIA 1997b), we calculated that 58% of total gasoline blending components were moved through pipelines and the remaining 42% were transported by tankers and barges. We used this split for movement of ethers.

4.1.5 Transportation, Storage, and Distribution of Petroleum Products

T&S&D. For the four motor vehicle fuels (CG, RFG, CD, and RFD), the T&S&D stage includes transportation to bulk terminals (primarily via pipelines), storage at the terminals, and distribution to refueling stations (primarily via tank trucks). LPG, used primarily in industrial, commercial, and residential sectors, is transported to bulk terminals via pipelines and trains and stored there until distribution to use sites via tank trucks. Residual oil is used primarily in marine vessels, electric power plants, and residential and commercial heating. It is transported via pipelines, barges, and trains to use sites. Table 4.3 presents energy efficiencies associated with T&S&D of these products. Table 4.4 presents process fuel shares.

VOC Evaporation and Fuel Spillage. NREL et al. (1991) estimated VOC evaporative emissions of 7.92 g/10^6 Btu and VOC spillage emissions of 3.34 g/10^6 Btu during T&S&D of RFG. These emission rates are used in the GREET model for CG and RFG. For diesel and LPG, no evaporative emissions are assumed. The spillage rate (in g/gal) is affected by the transportation distance and the mode of transportation. Because both of these could be different for different fuels, the spillage rate can also be different for different fuels. However, no data on spillage for fuels other than RFG are available. Emissions from spillage (in gal/gal of fuel handled) are assumed to be constant among CG, RFG, CD, RFD, LPG, and residual oil. On the basis of this assumption, the RFG spillage emission rate (in g/10^6 Btu) is adjusted to the spillage emission rates for diesel and LPG, considering their mass density and energy content. For residual oil, spillage emissions (in gal/gal of residual oil handled) are assumed to be 80% of those for RFG because of the short transportation distance and infrequent loading involved in residual oil T&S&D.

4.2 Natural-Gas-Based Fuel Cycles

4.2.1 Brief Description of the Natural Gas Industry

Eight NG-based fuel cycles are included in GREET: NG to CNG, LNG, methanol, DME, LPG, FTD, hydrogen, and electricity. Hydrogen can be produced in either gaseous or liquid form. In addition to these, GREET includes flared gas (FG) to methanol, DME, and FTD.

In 1996, the United States produced a total of 24.05 trillion cubic feet (ft^3) of NG with a net of 19.75 trillion ft^3 for market consumption (see Table 4.8). On the other hand, the total U.S. gas consumption was 22.1 trillion ft^3 (Table 4.9). The deficit between U.S. consumption and production was made by gas imported primarily from Canada.

The NG industry is usually separated into four stages: production, processing, T&S, and distribution (National Risk Management Laboratory 1996). In the production stage, NG is recovered and collected in NG and oil fields (about a quarter of total U.S. gas production is from oil fields, see Table 4.8). Collected NG is then delivered through collection pipelines to NG processing plants, which are usually located near NG and oil fields. In the processing stage,

Table 4.8 Natural Gas Production and Field Usage in the United States[a]

Type of Production or Use	Amount (trillion ft^3)	Percentage of Total Production
Gas well production	17.68	73.5
Oil well production	6.37	26.5
Total production	24.05	100
Gas used for reservoir repressuring	3.51	14.6
Gas vented or flared	0.27	1.1
Net gas for market	19.75	82.1

[a] From *Oil and Gas Journal* (1998). Data are for 1996.

Table 4.9 Natural Gas Consumption in the United States[a]

	NG Consumption (trillion ft^3)	Percentage of Total Consumption
Total consumption	22.1	100
Industrial sector	8.8	39.8
Residential sector	5.2	23.5
Commercial sector	3.2	14.5
Electric sector	2.7	12.2
Lease fuels[b]	2.2	10.0
Total supply	22.1	100
U.S. production	19.8	89.6
U.S. import[c]	2.3	10.4

[a] From EIA (1997c).

[b] Lease fuels include fuels used for pipelines, NG processing plants, and at the site of NG extraction for compression or power production in NG fields.

[c] Primarily from Canada.

high-value liquids (e.g., natural gasoline, propane, butane) are separated from NG, and impurities (e.g., sulfur compounds and CO_2) are stripped from NG to produce pipeline-quality NG. A processing plant usually contains fractionation towers and stabilization towers, dehydration facilities, wet gas compression, absorption or compression processes, and a refrigeration process.

During the T&S stage, NG is moved from NG processing plants to local distribution companies through pipelines. This segment of the industry includes large-size pipelines, compressor stations, and metering facilities. Compressor stations usually consist of piping manifolds, reciprocating engines or gas turbines, reciprocating or centrifugal compressors, and generators. Transmission companies have metering and regulating stations where they exchange gas with other transmission companies or deliver gas to distribution companies and large industrial customers. Storage facilities are necessary for the NG industry during off-peak demand periods. Gas is stored in underground facilities such as spent NG production fields, aquifers, and salt caverns or at aboveground LNG facilities, The facilities are equipped with compression stations. During the distribution stage, high-pressure NG from transmission pipelines is depressurized and delivered to end-use customers. This segment of the industry includes main pipelines, pressure-reducing stations, and service pipes.

4.2.2 System Descriptions and Energy Efficiencies of Natural Gas-Based Fuel Cycles

Natural Gas to Compressed Natural Gas. For this cycle, we assume that NG goes through each of the four stages described for the NG industry. That is, NG is produced in and processed near NG fields, transported through transmission and distribution pipelines to NG refueling stations, compressed to around 3,000 psi, and used to fuel CNGVs. Although a slow-filling process based on home refueling of CNGVs was proposed in the past and home refueling kits have been developed, we do not assume home refueling of CNGVs in our study.

Both electric and gas compressors can be used in CNG refueling stations to compress NG. Energy efficiency of NG compression is widely reported in literature to be around 95% (Wang 1996). In the gas industry, a rule of thumb for electric compression energy consumption is 1 kilowatt hour (kWh) of electricity per gallon of gasoline-equivalent NG dispensed. However, in small CNG refueling stations, where compression is inefficient, the actual measured electricity is between 1.75 and 2 kWh per gasoline equivalent gallon — almost twice as much as the gas industry value (Livengood 1999). If we use an electricity consumption value of 2 kWh, the energy efficiency for NG compression by electric compressors is about 94%. This percentage might represent the efficiency of electric compressors designed and produced in the early 1990s that are still in use. On the basis of an electricity consumption of 1 kWh, the energy efficiency is about 97.5%. This percentage could represent the efficiency of future electric compressors. Another consideration is that the energy efficiency of gas compressors could be lower than that of electric compressors. In our study, we used an energy efficiency of 95% for NG compression, assuming that, overall, half of the NG compressors in CNG refueling stations will be powered by electricity and half by gas. Electric compressors are more reliable than gas compressors. Small-scale stations may be equipped with electric compressors. If large CNG refueling stations are established as more CNGVs are introduced, station operators will have an incentive to switch from electric to gas compressors for energy cost savings.

Natural Gas to Liquefied Natural Gas. Relative to CNGVs, vehicles fueled with LNG (LNGVs) have one distinct advantage — a longer driving range per refueling. But cryogenic storage of LNG on board a vehicle presents technical and cost challenges. Although LNG can be used in light-duty vehicles, it has been promoted primarily for heavy-duty vehicle applications such as buses, long-haul trucks, and locomotives for its emissions benefits over diesel. GREET 1.5 includes LNG applications in light-duty vehicles.

We assume that LNG will be produced from remote, stranded gas in LNG plants near gas fields. This assumption enables us to eliminate NG transmission and distribution for the LNG pathway. The produced LNG is transported to LNG bulk terminals via ocean tankers, rail, barges, and/or trucks. LNG is finally transported from bulk terminals to refueling stations by trucks.

In LNG plants, substances such as water, CO_2, sulfur, and heavier hydrocarbons that would freeze during NG liquefaction must be removed before liquefaction. The purified NG is cooled at atmospheric pressure to about -260°F, the temperature at which NG becomes liquid. NG can also be liquefied using an expanded cycle in which the gas (under high pressure) is expanded rapidly, thereby cooling it to -260°F. Produced LNG is stored as a cryogenic liquid in insulated storage vessels at a pressure of 50–150 psi. LNG can be transported in these vessels by ocean tanker, truck, rail, or barge. Our study assumes that LNG is produced at large, centralized liquefaction facilities. Domestically produced LNG is transported via rail, barges, and trucks. Imported LNG is transported across the ocean via ocean tankers to major U.S. ports, where it is stored pending transportation (via rail, barges, and trucks) to inland terminals for storage and then distribution. Based on existing data, we assume an energy efficiency of 90% for NG liquefaction (Kikkawa and Aoki 1999).

Natural Gas to Liquefied Petroleum Gas. LPG (predominantly propane) can be produced in petroleum refineries and NG processing plants. The production of LPG in NG processing plants involves simple separation of LPG (and other NG liquids) from NG. We assume an energy efficiency of 96.5% for LPG production at NG processing plants. LPG is transported via pipelines, rail, barges, or/and trucks to bulk terminals for storage and distribution. LPG is finally transported to LPG refueling stations via trucks.

Natural Gas to Methanol. Methanol is produced through synthesis of a gaseous mixture of H_2, CO, and CO_2 (called syngas) into methanol. While methanol can be produced from biomass, coal, heavy oil, naphtha, and other feedstocks (Rees 1997), the availability of reasonably cheap NG feedstock makes the steam methane reforming (SMR) technology an economical way to produce methanol. SMR is a mature technology and is widely used in existing methanol plants. We assume that methanol plants are located near remote gas fields to take advantage of cheap, remote NG supplies.

In methanol plants, syngas is first produced from NG by means of SMR. This process requires a large amount of steam, and consequently consumes a large amount of energy. The syngas is then synthesized into methanol. Methanol synthesis is an exothermic reaction; a significant amount of steam can be generated during the process ($CO_2 + 3H_2 \rightarrow CH_3OH + H_2O$). Methanol plants are generally able to generate some excess amount of steam that can be exported to nearby plants.

The optimal mole ratio of syngas among H_2, CO, and CO_2 ($[H_2\text{-}CO_2]/[CO+CO_2]$) for methanol synthesis is between 2.05 and 2.1 (Gohna 1997). Syngas from reformers, however, has a ratio of around 2.8 and contains excess H_2. Three options are available to achieve the desired mole ratio: (1) burn the excess H_2 as process fuel, (2) separate and purify the excess H_2 for export to other nearby chemical plants (such as ammonia fertilizer plants or petroleum refineries), and (3) add CO_2 to the syngas to convert some of the H_2 to CO through a shift reaction. For the third option, Stratton et al. (1982) reported that adding 6% CO_2 (by volume) to syngas can increase methanol yield by about 20%. The required CO_2 can be imported from sources outside of methanol plants. The choice among the three options depends on the availability of CO_2 and the value of H_2. In our analysis, we chose the first option (i.e., the H_2 is used as process fuel) to achieve the proper H_2 to CO ratio.

A recent technology development for producing syngas to achieve the desired molar ratio is to integrate a partial oxidation (POX) process using pure oxygen with the SMR process. The integrated design, sometimes referred to as “two-step reforming,” requires production of O_2 in methanol plants and is suitable for mega-size (3,000–5,000 ton/d capacity) methanol plants (Berggren 1997; Gronemann 1998; Islam and Brown 1997). No data regarding energy use and emissions are available for the two-step reforming design; we did not include it in our analysis.

Dybkjar (1996) reported that the energy efficiency of methanol plants ranges from 65% to 70%. Islam and Brown (1997) reported an NG requirement of $34–34.8 \times 10^6$ Btu (HHV) per metric ton of methanol output in methanol plants. Using an HHV of 21.7×10^6 Btu per metric ton of methanol, we calculate an energy efficiency of 62.4–63.8% for the reported input and output numbers. Abbott (1997) reported an energy efficiency of 57.9–74.7% for compact methanol production units applicable to offshore oil recovery platforms. Berggren (1997) reported that 31.3×10^6 Btu of NG is required to produce one metric ton of methanol, which translates into an energy efficiency of 69.3%.

The energy efficiency of methanol plants is affected by steam export. If methanol plants are designed to produce and export steam, they may be less efficient (without considering energy contained in the exported steam). Unfortunately, none of the studies cited above states whether and how much steam is produced from the plants evaluated. We use an energy conversion efficiency of 65% for methanol plants that produce steam for export. Furthermore, we assume that the conversion efficiency (accounting for the Btu contained in steam) is 72% for these plants. On the basis of this assumption, about 111,000 Btu of steam could be produced for each million Btu of methanol produced. For plants that do not produce and export steam, we assume an energy efficiency of 68%.

Some of the total amount of NG input in methanol plants is used as feed for syngas production, and the remainder is used as process fuel. Abbott (1997) reported that 78–88% of the total NG input in methanol plants is used as feed. We assumed that 83% of NG input is used as feed and the remaining 17% as fuel. This feed/fuel split of NG is used in the GREET model to calculate emissions of criteria pollutants during methanol production. In particular, the amount of NG burned and emission factors of NG combustion are used to determine combustion emissions of NG fuel in methanol plants.

The catalysts that are used in reformers can be poisoned by sulfur contained in NG feed. The sulfur, usually in the form of hydrogen sulfide (H_2S), must be removed before NG goes into the reformer. Usually, zinc oxide (ZnO) is used for desulfurization of NG, which occurs via the following reaction:

$$H_2S + ZnO \rightarrow ZnS + H_2O \qquad [4.1]$$

The zinc sulfide (ZnS) produced in this way is disposed as a solid waste. So, in our simulation, we assume sulfur in NG feed ends up as a solid waste, not as SO_2 emissions to the air. We assume the desulfurization measure is used for plants producing methanol, H_2, DME, and FTD.

Because syngas is pressurized in reformers, fugitive emissions of CO and CO_2 may be leaked from reformers. But there are no data to estimate the amount of fugitive emissions. We estimated emissions from the SMR process using the process described in the section on FTD production.

We assume that domestically produced methanol is transported via pipelines to bulk terminals for storage and distribution. Methanol is then transported to refueling stations via trucks. Imported methanol is transported across the ocean via ocean tankers to major U.S. ports. It is then transported through pipelines to inland bulk terminals and then to refueling stations via trucks.

Natural Gas to Gaseous Hydrogen in Centralized Plants. We assume that large-size, centralized H_2 production plants are located near NG fields. Gaseous H_2 is transported through pipelines to refueling stations, where it is compressed to 5,000–6,000 psi for fueling FCVs. We assume that more energy is needed to transport H_2 than NG; a greater volume of H_2 must be transported because the energy content per unit of volume of H_2 is lower than that of NG. We also assume that a larger amount of energy is required to compress H_2 than to compress NG because H_2 needs to be compressed twice as much as NG for vehicle refueling.

Several alternative schemes, such as POX, autothermal reforming (ATR), and plasma reforming, have been developed and used commercially to produce H_2. However, the majority of large-scale H_2 plants still employ SMR. We used SMR plants in our analysis. The SMR technology used in commercial H_2 plants involves conventional, one-step steam reforming carried out in high-alloy tubes placed inside a large NG-fired furnace. NG is normally preheated by the waste heat from the SMR reformer, and the feed gas is processed through a bed of ZnO sorbent (see above section on methanol production) to remove the sulfur (which poisons the reforming catalysts). Steam is added to the desulfurized NG feed, and the mixture of NG and steam is further preheated before entering the reformer, where CH_4 is converted into H_2, CO, and CO_2 by means of nickel-based reforming catalysts. The produced hot syngas, at a temperature of 900–930^{o}C, exits the SMR reformer and is cooled by water before entering the shift converter, where shift catalysts convert CO and steam to CO_2 and additional H_2. The gas from the shift converter is further cooled to ambient temperature before entering a pressure swing adsorption unit, where high-purity H_2 is produced; the remaining gas mixture is used in the SMR reformer as supplemental fuel for the burners. To improve the energy efficiency of H_2 production, combustion air for the burners can be preheated by means of waste heat from the reformer's heat recovery section. H_2 plants can generate a significant amount of steam. Some of the steam produced in an H_2 plant is used as process steam within the plant, while the remainder can be exported to nearby chemical plants.

According to Dybkjar et al. (1998), an H_2 plant with a production capacity of 13,500 normal cubic meters (nm^3) H_2 per hour requires 3.82×10^6 kilocalories (kcal) of NG input to produce 1,000 nm^3 of H_2. This is together with 0.78×10^6 kcal of steam export. On the basis of a heat content of 2,500 kcal per nm^3 of H_2 at normal pressure, we calculated an energy efficiency of 65% without considering steam credit and 86% considering steam credit. Sharma (1999) reported an energy efficiency of 82–86% with steam credit considered and 61–73% without steam credit. In our analysis, for H_2 plants designed to produce steam for export, we assume an energy efficiency of 67% (without steam credit) and 85% (with steam credit). This assumption means that 269,000 Btu of steam is produced for each 1 million Btu of H_2 produced. For H_2 plants that do not produce steam, we assume an energy efficiency of 73%.

On the basis of data in Dybkjar et al. (1998), for the 1.54 million Btu of NG input, we estimate that 1.27 million Btu goes to the SMR reformer as feed and 0.37 million Btu goes to burners to provide process heat. That is, the split for NG input in H_2 plants is 76% feed and 24% fuel.

The excess steam in H_2 plants can be exported if some other chemical plants (such as petroleum refineries) are located nearby. The steam cannot be recovered and used if H_2 plants are located in remote areas where no other chemical plants exist. We assume that centralized H_2 plants are located near some other chemical plants so the steam can be exported to these plants and used there.

Emissions of NG fuel are calculated on the basis of the estimated amount of NG consumed as fuel (17% of total NG input as estimated for methanol production) and the emission factors of NG combustion.

Natural Gas to Gaseous Hydrogen at Refueling Stations. Recent research reveals that the cost of developing the pipeline distribution infrastructure for gaseous H_2 could be enormous (Wang et al. 1998). To avoid the high cost and institutional barriers of developing an extensive H_2 pipeline system, some researchers have evaluated the option of producing H_2 at refueling stations (Thomas et al. 1997). This approach, called the “decentralized production pathway,” involves transporting NG through existing pipelines to refueling stations, where small-scale SMR units would be installed to produce gaseous H_2. Thus, the pathway includes NG transmission and requires SMR reformers, storage tanks, and compression facilities at refueling stations.

Thomas et al. (1997) report an energy efficiency ranging from 55–65% for producing and compressing H_2 in refueling stations. The decentralized H_2 production pathway makes steam production and export impractical. As stated, centralized H_2 plants without steam production have an energy efficiency of 70%. Decentralized H_2 production at refueling stations would likely be less efficient than in centralized plants. We assume an energy efficiency of 65% for decentralized H_2 production and a compression efficiency of 92% for both centralized and decentralized H_2 production.

Natural Gas to Liquid Hydrogen in Centralized Plants. The gaseous H_2 produced at centralized H_2 plants can be liquefied. Liquid H_2 can be stored and transported as a cryogenic liquid. One advantage of using liquid H_2 in motor vehicles is a longer driving range per refueling than the range allowed by using gaseous H_2. Liquid H_2 can be transported from H_2 plants via ocean tankers, rail, barges, and trucks in cryogenic vessels to bulk terminals, stored there, and then transported to refueling stations via trucks. There are two major disadvantages of using liquid H_2: (1) liquefaction of H_2 requires a considerable amount of energy (resulting in fewer energy and emissions benefits); and (2) cryogenic transportation and storage of liquid H_2 pose technical and cost challenges. Besides the energy efficiency for producing gaseous H_2, we use an energy efficiency of 82% for liquefying the gaseous H_2 for near-term plants and 85% for longer-term plants.

Natural Gas to Dimethyl Ether. DME, which has physical properties similar to those of LPG, has been proposed and tested as an alternative to diesel fuel in compression-ignition engines. Use of DME in diesel engines offers emissions reduction benefits for NO_x and PM. For the NG-to-DME cycle, we assume in this study that DME is produced near gas fields.

Transportation from DME plants to refueling stations is assumed to be similar to that for LPG; DME is transported through ocean tankers, pipelines, rail, barges, and trucks to DME bulk terminals, where it is stored until transport to refueling stations via trucks.

DME is now used predominantly as an aerosol propellant and is produced from methanol through a dehydration process. The production involves a two-reactor process train in which methanol is first synthesized from syngas. DME is then produced by dehydration of two methanol molecules to one DME molecule. The recent development of new, dual-function catalysts allows the synthesis and dehydration to take place within a single reactor. The new one-step production approach results in an energy efficiency as high as 70% and significantly improves the economics for large-scale DME plants (Blinger et al. 1996; Hansen et al. 1995; Kikkawa and Aoki 1998; Verbeek and Van der Welde 1997).

The desired mole ratio among H_2, CO, and CO_2 ($[H_2\text{-}CO_2]/[CO+CO_2]$) for DME synthesis is around 2.1. Syngas from SMR reformers, however, has a ratio of about 2.8 and contains a high concentration of H_2. To achieve the desired molar ratio for DME production, CO_2 must be added or H_2 must be removed. The newly developed ATR process, which includes an adiabatic reactor that uses oxygen together with a much smaller amount of steam, produces a syngas with a ratio below 2.0. Another new technology integrates an SMR reformer with a POX reformer (which uses pure oxygen to produce syngas) to achieve the desired molar ratio. This technology is also referred as to a two-step reforming technology (as discussed in the section on methanol production). The ATR and the two-step reforming technologies are reported to be particularly suitable for mega-size (5,000–10,000 ton/d capacity) DME plants (Verbeek and Van der Welde 1997; Hansen et al. 1995).

No external furnace is required with the ATR system, so no NG is burned as process fuel. Instead, a portion of the NG feed to the ATR reactor is oxidized inside the front end of the reactor to provide the heat necessary for conversion of NG to syngas. Because there is a small amount of nitrogen in the NG feed, a small amount of NO_x is formed inside the ATR reactor. The NO_x is eventually emitted into the atmosphere after final product separation. However, the amount of NO_x emissions from the ATR system should be smaller than the amount from the SMR system.

To produce one metric ton of methanol-equivalent (on a Btu basis), DME requires 29.1 giga joule (GJ) (LHV) of NG input (Hansen et al. 1995; Dybkjar 1996). In addition, 76 kWh of electricity is coproduced per metric ton of methanol-equivalent DME. The numbers imply an energy conversion efficiency of 68.8% without considering electricity credit.[1] If the energy (in Btu) contained in the steam that is subsequently used for electricity generation is taken into account, the efficiency is 71.7%. On the other hand, using data presented in Kikkawa and Aoki (1998), we calculate an energy efficiency of 65% for DME production without considering steam credit. With steam credit considered, the efficiency is increased to 66.8%.

Hansen et al. (1995) reported CO_2 and NO_x emissions of 440,000 and 95 g/metric ton (23,158 and 5.263 g/10^6 Btu) of DME, respectively. Using the above energy input data and the carbon balance method, we independently calculated CO_2 emissions of 446,000 g/metric ton of DME, which is consistent with the number reported in Hansen et al. In our analysis, we use an energy conversion efficiency of 68% for DME production with steam credit not considered. With steam credit considered, we assume an energy efficiency of 71%. On the basis of these assumptions, about 44,000 Btu of steam is produced for each million Btu of DME produced.

As explained above, the ATR technology does not require combustion of NG to provide the heat required for DME production. So all NG input for DME production is allocated to feed. Emissions of criteria pollutants from the ATR system for DME production are estimated as described in the section on FTD production.

Natural Gas to Fischer-Tropsch Diesel. The Fischer-Tropsch process produces middle distillates containing no sulfur and virtually no aromatics (with cobalt-based catalysts); it also produces naphtha and wax. Using middle distillates in compression-ignition engines helps reduce NO_x and PM emissions. The Fischer-Tropsch reaction process was used by Germany during World War II to produce diesel fuel and by South Africa during the oil embargo against that country's apartheid. Currently, several major companies are actively pursuing the production of middle distillates through the Fischer-Tropsch process. Commercial Fischer-Tropsch synthesis processes are available from Sasol, Ltd., Shell International Oil Products, Exxon Corporation, Syntroleum Corporation, and Rentech, Inc. Development of new catalysts, especially cobalt-based catalysts, for the Fischer-Tropsch process has allowed production of a syngas with the desired mix of CO and H_2 for FTD production.

An FTD production plant consists of three major steps: (1) production of syngas, (2) synthesis of middle distillates, and (3) upgrading of products. At the syngas production stage, sulfur in NG is removed through treatment in a ZnO sorbent bed before the gas enters the reformers (see the section on methanol production). Either POX or ATR reformers can be used for syngas production. One FTD plant design analyzed by Choi et al. of Bechtel Corporation employs a POX reformer and a small SMR reformer to produce syngas with the desired H_2/CO ratio of about 1.9 (Choi et al. 1997a,b). The oxidation reaction in the POX reformer uses pure oxygen produced in an oxygen plant within the FTD plant. On the other hand, the FTD plant design by Syntroleum includes the ATR reformer, and the oxidation reaction in the ATR reformer employs ambient air, so no oxygen plant is required. In our analysis, we rely primarily on the data from the Syntroleum design.

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[1] With a low heating value of 57,000 Btu/gal and a density of 2,996 g/gal for methanol, one metric ton of methanol contains 19 × 10^6 Btu of energy. One GJ is 0.9486 × 10^6 Btu.

After cooling in a heat recovery unit, the produced syngas is directed to a Fischer-Tropsch synthesis reactor to produce middle distillates and other liquid products. The Fischer-Tropsch reaction is exothermal, so the excess heat from the process can be recovered with steam generation. The generated steam can be exported to nearby chemical plants or can be used to generate electricity for export.

A variety of hydrocarbon liquids can be produced from the Fischer-Tropsch reaction, depending on the operating temperature of the reactor. For example, an operating temperature of 180–250^{o}C helps produce predominately middle distillates and wax; an operating temperature of 330–350^{o}C helps produce gasoline and olefins. In any case, a mix of different hydrocarbon liquids is produced from the FTD synthesis stage.

The final stage in an FTD plant, upgrading liquid products into useful fuels, is easier than refining crude oil because the synthetic products contain virtually no sulfur and fewer aromatics. Consequently, the final products from FTD plants are considered to be a premium blendstock for diesel fuels.

In the POX design presented by Choi et al. (1997a,b) (a POX reformer and a small SMR reformer), the split of total NG input between the POX and SMR reformers is 30 to 1. That is, about 3.2% of the total NG input goes to the SMR reformer. Furthermore, of the total NG to the SMR reformer, we assume that the split between NG as feed and NG as fuel in the SMR reformer is 83%/17% (the same split that we developed for SMR reformers for methanol production). So, overall, only about 0.54% (3.2% × 17%) of the total NG input is used as fuel in the Bechtel FTD design. Combustion of the 0.54% of NG input produces a small amount of criteria pollutant and GHG emissions. The Syntroleum design, using the ATR reformer, does not require combustion of NG, so all NG input is used as feed; we adopted this approach in GREET 1.5.

A recent in-house assessment of FTD production at Argonne National Laboratory provided the following results: FTD production with the POX design has an energy efficiency of 55% and a carbon efficiency of 71%; FTD production with designs by Sasol, Shell, and Exxon has an energy efficiency of 62% and a carbon efficiency of 78%; and FTD production with the Syntroleum design has an energy efficiency of 57% and a carbon efficiency of 72% (Marshall 1999). These energy efficiencies assume that the excess steam from FTD plants is recovered for export or electricity generation.

Syntroleum reports that its process achieves a carbon efficiency of 75% and an energy efficiency of 67% when the excess steam is recovered for electricity generation or steam export to other facilities (Russell 1999). If the excess steam is not recovered, the energy efficiency is 53%. Because various hydrocarbons (ranging from C4 to over C25) are produced from the Fischer-Tropsch process, carbon emissions cannot be calculated from the amount of feed and the total amount of hydrocarbons produced. In GREET, carbon emissions are calculated directly from the carbon conversion efficiency. In our analysis, for plants that employ steam generation, we assume an energy efficiency of 53% for FTD production (not taking into account credit for the excess steam generated). With steam credit taken into account, we assume an energy efficiency of 67%. On the basis of these assumptions, 264,000 Btu of steam is generated for each million Btu of product fuel produced. For FTD plants that do not employ steam generation, we assume an energy efficiency of 54% and a carbon conversion efficiency of 72%.

The Syntroleum process produces two liquid products: C5-C9 naphtha (about 30% of total products) and C10-C20 middle distillates (about 70% of total products). The naphtha can be used as a gasoline blendstock but its high RVP presents a problem for blending it into gasoline. Research is currently under way to explore use of naphtha as a fuel-cell fuel because it contains a high concentration of hydrogen. The middle distillates from FTD plants can be used as a diesel blendstock or as a neat fuel in diesel engines.

All NG input in FTD plants goes to the ATR reformer; none is burned directly. On the other hand, the ATR reformer generates some criteria pollutant emissions. According to Syntroleum researchers, VOC emissions from FTD plants should be about equal to those from petroleum refineries (on the basis of per-unit-of-product output); CO emissions from FTD plants should be fewer than 100 tons per year for a 1,000-barrels/day plant; and NO_x emissions should be less than 60 tons a year (Russell 1999). Using these values and based on an assumed plant capacity factor of 85%, we estimate a CO emission rate of 58.6 g/10^6 Btu of fuel output and a NO_x emission rate of 35.2 g/10^6 Btu. These emission rates are based on manufacturer-suggested emissions limits. In the GREET simulation, we assume half of the estimated emissions rates.

Flared Gas to Methanol, DME, and FTD. Table 4.10 presents the amounts of NG produced and used worldwide. In the United States, the amount of gas vented or flared represents a tiny portion of the total amount of gas produced. Vented or flared gas is usually the associated gas produced from oil fields where NG pipelines and processing infrastructure are not available to process the gas into a commercial product. Worldwide, about 5% of the total NG production is flared. Some researchers suspect that the actual amount of gas flared is far greater than reported. As some countries started to impose economic penalties for gas flaring in an effort to reduce CO_2 emissions, oil companies began to look for other alternatives to dispose or use associated gas from oil fields. One option is to build chemical plants near oil fields to produce chemicals from flared gas. To simulate the energy and emissions impacts of using flared gas, we establish cases for producing methanol, DME, and FTD from flared gas as well as from conventional natural gas.

Inexpensive NG feedstock is vital to allow methanol, DME, and FTD to compete with petroleum-based fuels. Inexpensive gas is available in remote oil and gas fields where NG distribution infrastructure does not exist. Production of these fuels from remote gas can overcome the NG distribution infrastructure hurdle in remote locations.

For methanol production from FG, we assume an energy efficiency of 65% and no steam production. This efficiency is lower than the efficiency associated with producing methanol from NG, because there is not much incentive to increase the conversion efficiency for remote methanol plants with FG as feedstock.

Table 4.10 Worldwide Natural Gas Production and Flaring[a]

Region	NG Reserve[b]	Annual Production[b]	Annual Flared Gas[c]	Flared Gas as Percentage of Production
West Hemisphere	517.7	30.7	0.86	2.8
West Europe	170.4	9.5	0.13	1.4
East Europe	2,003.2	26.9	NA[d]	NA
Asia Pacific	320.6	7.7	0.287	3.7
Middle East	1726.1	4.7	0.914	19.4
Africa	348.6	3.0	1.637	54.6
World	5,086.0	82.5	3.828	4.6

[a] Amounts in trillion ft^3; data are for 1996.

[b] From *Oil and Gas Journal* (1998).

[c] From EIA (1998a).

[d] NA = not available.

For DME production from FG, we assume an energy efficiency of 66% with no steam production.

For FTD production from FG, we use data provided by Syntroleum (Russell 1999). Because production from FG will likely occur in remote locations where steam or electricity export may not be feasible, and because FG itself is almost free, we do not assume that the excess steam in FTD plants will be recovered. We assume an energy efficiency of 52% for FTD production. Carbon efficiency for FTD production from FG is assumed to be 65%.

4.2.3 Summary of Energy Efficiencies of Natural Gas-Based Cycles

Table 4.11 lists values for energy efficiencies of NG-based fuel-cycle stages used in GREET 1.5. For comparison, the table lists efficiencies used in other fuel-cycle studies. Note that efficiencies for production of methanol, H_2, DME, and FTD are for plants without steam co-generation designs.

For safety reasons, vapors are usually vented into the atmosphere to keep the pressure below its limit. Because of this so-called boiling loss, the energy efficiency of LNG T&S&D is lower than that of T&S&D of other liquid fuels. An energy efficiency of 95% is assumed in GREET 1.5 for LNG T&S&D. By comparison, an energy efficiency of 98% is assumed in GREET 1.5 for LPG T&S&D.

As discussed in Section 4.2.2 on NG-based fuel production, we assume that methanol and H_2 are produced by means of the SMR technology and DME and FTD by means of the POX technology. The SMR technology requires that some of the NG input to plants be burned in an external burner to provide steam for syngas production, while the POX technology does not require external combustion of NG. By using the mass balance between NG input and product output, we estimate that for methanol production, 83% of NG input ends up as feed for syngas production and the remaining 17% is used as process fuel. We estimate that for H_2 production,

Table 4.11 Energy Efficiencies of Natural Gas Fuel-Cycle Stages (%)

NG-Based Fuel-Cycle Stage	GREET	Delucchi (1991)	Bentley (1992)	Ecotraffic, AB (1992)	NREL (1992)	Smith (1993)	Acurex (1995)	Darrow (1994a)	Darrow (1994b)
NG recovery	97.0	97.2	94.0	97.0	NE[a]	NE	96.2	NE	NE
NG processing	97.5	97.5	97.0	98.0	NE	NE	96.2	NE	NE
NG T&D	97.0	96.4	97.0	98.0	NE	NE	NE	NE	NE
NG compression	95.0	95.0	87.0	93.0	NE	NE	NE	97.9	98.0
NG liquefaction	90.0	83.2	NE	90	NE	NE	85.7	NE	NE
LNG T&S&D	95.0	96.5	NE	94	NE	NE	NE	NE	NE
MeOH[b] production	68.0	45.9	70.0	60.0	NE	NE	68.3	66.4	NE
MeOH from FG	65.0	NE	NE	NE	NE	NE	NE	NE	NE
MeOH T&S&D	97.0	96.2	90.2	97.8	NE	NE	NE	97.7	NE
DME production	69.0	NE	NE	NE	NE	NE	NE	NE	NE
DME from FG	66.0	NE	NE	NE	NE	NE	NE	NE	NE
DME T&S&D[c]	97.5	NE	NE	NE	NE	NE	NE	NE	NE
FTD production	54.0	NE	NE	NE	NE	NE	NE	NE	NE
FTD from FG	52.0	NE	NE	NE	NE	NE	NE	NE	NE
FTD T&S&D	97.0	NE	NE	NE	NE	NE	NE	NE	NE
LPG production[d]	96.5	96.7	NE	NE	NE	NE	NE	NE	NE
H_2 centralized production	73.0	NE	NE	NE	68.0	68.0	61.1	NE	NE
H_2 liquefaction	82.0	70-74	NE	70	NE	68.0	NE	NE	NE
H_2 decentralized production	65.0	NE	NE	NE	NE	NE	NE	NE	NE
Gas H_2 T&S&D	97.0	90.9	97	NE	NE	NE	NE	NE	NE
Gas H_2 compression	92.0	76.9	80	NE	NE	NE	NE	NE	NE
Liquid H_2 T&S&D	95.0[e]	NE	NE	85.5	NE	NE	NE	NE	NE

[a] NE = not estimated.

[b] MeOH = methanol.

[c] The energy efficiency for T&S&D of LPG is adopted for DME.

[d] The energy efficiency for the T&S&D of LPG is presented in Table 4.3.

[e] An efficiency for T&S&D of liquid hydrogen lower than the efficiencies for T&S&D of other liquid fuels is assumed here primarily because the energy content of liquid hydrogen is lower than those for other liquid fuels.

the split is about the same as for methanol production. For DME and FTD production, we assume all the NG input is used as feed for syngas production.

Process fuel shares for each of the NG-based cycle stages are presented in Table 4.12.

4.2.4 CH_4 Emissions during Natural Gas Production and Transportation

CH_4 emissions during the transfer of NG from NG fields to user sites include three types: fugitive emissions, vented emissions, and combustion emissions (National Risk Management Laboratory 1996). Fugitive emissions are unintentional leaks from sealed surfaces such as packings and gaskets or from pipelines that result from corrosion and faulty connections. Vented emissions, released by design or operation practice, include emissions from continuous

Table 4.12 Process Fuel Shares of Natural Gas Fuel-Cycle Stages (%)

NG-Based Fuel-Cycle Stage	Residual Oil	Diesel	Gasoline	NG	Electricity	Feed Loss
NG recovery	1	10	1	77	1	11
NG processing	0	1	0	91	3	6
NG T&D	0	0	0	86	1	13
NG compression	0	0	0	50	50	0
NG liquefaction	0	0	0	98	2	0
LNG T&S&D	47	19	0	28	0	7
MeOH production	0	0	0	99.8	0.2	0
MeOH T&S&D	74	15	0	4	7	0
DME production	0	0	0	99.8	0.2	0
DME T&S&D	74	15	0	4	7	1
FTD production	0	0	0	100	0	0
FTD T&S&D	74	15	0	4	7	0
LPG production	0	1	0	96	3	0
H_2 production	0	0	0	99.8	0.2	0
H_2 liquefaction	0	0	0	99.8	0.2	0
Gas H_2 T&S&D	0	0	0	86	1	13
Gas H_2 compression	0	0	0	50	50	0
Liquid H_2 T&S&D	0	100	0	0	0	0

process vents such as dehydrator reboiler vents, from maintenance practices such as blowdowns, and from small individual sources such as gas-operated pneumatic device vents. Combustion emissions are exhaust emissions from combustion sources such as compressor engines, burners, and flares. GRI and EPA co-funded a study to estimate total CH_4 emissions of the U.S. gas industry in 1992 (Harrison et al. 1996). The study found that, of the total CH_4 emissions, 62% are fugitive emissions, 30% are vented emissions, and the remaining 8% are combustion emissions.

Table 4.13 presents estimated CH_4 emissions for each stage of the NG cycle. As the table shows, a large amount of CH_4 emissions occur during NG transmission and distribution.

On the other hand, EIA estimated that between 1992 and 1996, an annual average of 0.31×10^6 metric tons of CH_4 were produced from NG wellheads, 0.85×10^6 metric tons from gathering pipelines in NG and oil fields, 0.7×10^6 metric tons from NG processing plants, and 0.18×10^6 metric tons from heaters, separators, and dehydrators (EIA 1997a). As stated previously, we allocate 10% of the gathering pipeline emissions to crude production and 90% of the emissions from heaters, separators, and dehydrators to oil production. Thus, the total of CH_4 emissions from gas production is 1.793×10^6 metric tons ($0.31 + 0.85 \times 90\% + 0.7 + 0.18 \times 10\%$). EIA reported an annual average unprocessed NG production rate of 23.25×10^{12} ft^3 and processed dry NG production rate of 18.43×10^{12} ft^3 between 1992 and 1996 (EIA 1997c). Using these figures, we calculate a CH_4 emission factor of 14.3 g/10^6 Btu of NG produced for NG wellheads and 35.4 for NG gathering pipelines, with a total of 49.7 g/10^6 Btu of NG produced during the production stage. We estimate 41.9 g/10^6 Btu of NG processed during the NG processing stage.

Table 4.13 CH_4 Emissions from Natural Gas Fuel-Cycle Stages[a]

Stage	Total CH_4 Emitted (10^9 ft^3)	Percent of Total CH_4 Emissions	CH_4 Emissions: Percent of Volumetric NG Produced[b]	CH_4 Emissions: g/10^6 Btu of NG Throughput[c]	CH_4 Emissions: g/10^6 Btu of NG Throughput[d]
Production	84.4	26.8	0.38	78.74	49.7
Processing	36.4	11.6	0.16	33.16	41.9
T&S	116.5	37.1	0.53	109.83	184.4[e]
Distribution	77.0	24.5	0.35	72.53	NE [f]
Total	314	100.0	1.42	294.25	276.0

[a] From National Risk Management Laboratory (1996), except as noted.

[b] Total NG production was 22.13 × 10^{12} ft^3 in 1992.

[c] Calculated by using the following formula: [(CH_4 emissions as % of volumetric gas produced) × 19.23 (g/ft^3 for methane)] ÷ 928 (Btu/ft^3 for NG, LHV) × 1,000,000.

[d] These values were calculated from 1996 data presented by EIA (1997a). They are presented here for comparison purposes. See text for EIA data.

[e] This value includes emissions from both NG transmission and distribution.

[f] NE = not estimated.

EIA estimated an annual average of 3.57 × 10^6 metric tons of CH_4 from NG transmission and distribution in 1995 (EIA 1997a). Between 1992 and 1996, the annual average NG consumption in the U.S. was 20.82 × 10^{12} ft^3 (EIA 1997c). Using these figures, we calculate a CH_4 emission factor of 184.4 g/10^6 Btu throughput for NG transmission and distribution.

The values estimated from EIA data are presented in Table 4.13 for comparison. As the table shows, estimates from the two sets of data are very close. This should be the case, because EIA's estimates of CH_4 emissions were largely based on the results of the GRI/EPA study. For further comparison, a Canadian report estimated CH_4 emissions of 101.95 g/10^6 Btu of NG produced, 22.66 g/10^6 Btu of NG processed, 31.15 g/10^6 Btu of NG transmitted, and 56.64 g/10^6 Btu of NG distributed in Canada (Canadian Gas Association 1994). Thus, the Canadian total CH_4 emission rate is 212.4 g/10^6 Btu of NG delivered to consumers, which is 23% lower than the U.S. emission rate.

The GRI/EPA study estimated CH_4 emissions for 1992. The study maintained that as NG demand increases in the future, CH_4 emission rates (as % of NG production) will probably be reduced, while total CH_4 emissions may remain relatively constant. This assumption is based on the fact that fugitive and vented CH_4 emissions are mainly determined by the capacity of NG production, transmission, and distribution systems more than by NG throughput from the systems. This is especially true in the United States, where there is an excess capacity of transmission and distribution systems at present. The study concluded that while total CH_4 emissions in 1992 represented about 1.42% of NG production (on a volumetric basis) in that year, a 30% increase in NG demand may result in an emission factor of 0.4-1.0% for the 30% incremental NG demand. On the other hand, Table 4.13 shows that in 1996, the CH_4 emission rate was 1.42%, on a volumetric basis. Thus, increased NG demand does appear to reduce the CH_4 emission rate.

A question relevant to this study is whether we should assume reduced CH_4 emission rates for NG to be used in vehicles in the form of CNG, LNG, LPG, methanol, DME, hydrogen, or FTD. For a marginal analysis of each fuel, we should assume a much lower CH_4 emission rate (probably 0.4–1.0% of NG produced, as estimated by the GRI/EPA study). Such a marginal analysis requires an assumption of how much NG will be used in motor vehicles.

Without a detailed, quantitative marginal analysis, we assume the following CH_4 emission rates for each of the four stages of the NG cycle. For NG production and processing, increased demand for NG for use in NG-based transportation fuels will probably require an increase in NG production and processing capacity. New capacity should be more efficient and generate fewer CH_4 emissions. We use a CH_4 emission rate of 0.35% for NG production and 0.15% for NG processing, compared to 0.38% and 0.16% as estimated for 1992 in the GRI/EPA study. For transmission and distribution systems, as long as the increased demand for NG for transportation use does not require construction of new pipelines, CH_4 emissions from NG transmission and distribution for transportation fuels should be much fewer than those for the current system. We assume that the CH_4 emission rates for future use of NG in transportation technologies are half of those for current uses of NG. Thus, a CH_4 emission rate of 0.27% for NG transmission and 0.18% for NG distribution are assumed in GREET 1.5 for NG. Note that except for CNG, NG-based fuels (LNG, LPG, methanol, DME, FTD, and hydrogen) do not require NG transmission and distribution. Thus, no CH_4 emissions for NG transmission and distribution are assigned to these fuels.

Note that GREET calculates combustion CH_4 emissions for each stage of the NG cycles. The above-cited CH_4 emission rates based on the GRI/EPA study include CH_4 combustion emissions as well as fugitive and vented CH_4 emissions. To avoid double-counting CH_4 combustion emissions, GREET-calculated CH_4 combustion emissions are automatically subtracted by the model from the above CH_4 emission rates.

EIA (1997a) maintained that a small amount of NG is flared during NG production, probably from NG production from oil wells. As estimated in a previous section, an annual average of 3.594×10^6 metric tons of NG is flared in the United States. We assume that 85% of that total is from oil production. Thus, the remaining 15% (0.539×10^6 metric tons) is from NG production. The annual total U.S. gas production was 18.43×10^{12} ft^3 between 1992 and 1996. By using these figures, we estimate an NG flaring rate of 31.4 g/10^6 Btu of NG produced — or 1,460 Btu of NG flared per 10^6 Btu of NG produced.

During storage and transport of LNG in cryogenic vessels, LNG boils off because of heat accumulation inside the vessels. Gaseous NG from this boiling off process is released to maintain a safe level of pressure inside the vessels. In some practices, gaseous NG is released to the atmosphere. On the basis of information from Acurex (1995), we calculate an NG emission rate of 79.55 g per 10^6 Btu of LNG during LNG T&S&D. We assume that 95% of the released NG is CH_4.

Release of VOC during methanol T&S&D is calculated by assuming that the spillage rate (in gal/gal of methanol handled) is the same as the rate for RFG. The gal/gal spillage rate is then converted into g/10^6 Btu of methanol handled by using the mass density and energy content values for RFG methanol.

4.2.5 Noncombustion Emissions during Natural Gas Processing and Production of Natural Gas-Based Fuels

NG Processing. SO_x emissions are generated during sweetening of NG (removal of H_2S contained in NG). Using a formula contained in EPA's AP-42 document (EPA 1995), and assuming an H_2S mole content for NG of 0.3% and 99% SO_x control efficiency in NG processing plants, we calculate that the SO_x emission rate from NG sweetening is 2.226 g/10^6 Btu of NG processed.

Processing of raw NG in NG processing plants strips the CO_2 contained in raw NG. The eliminated CO_2 is usually emitted into the atmosphere. EIA estimated that between 1992 and 1996, an annual average of 0.403×10^{12} ft^3 of nonhydrocarbon gases were removed — for an annual average of 18.43×10^{12} ft^3 of dry NG produced (EIA 1997a). We assume that 90% of the removed nonhydrocarbon gases are CO_2. Using a CO_2 density of 52.65 g/ft^3 and an NG energy content of 930 Btu/ft^3 (LHV), we calculated a CO_2 emission rate of 1,237 g/10^6 Btu NG produced. We apply this rate in GREET 1.5. In comparison, the Canadian Gas Association (1994) estimated that the amount of CO_2 stripped in NG processing plants was about 1,125 g/10^6 Btu of NG processed.

Production of Methanol, Hydrogen, DME, and FTD. Production of these fuels involves syngas generation, which produces CO_2 emissions. Of course, some of the CO_2 generated this way is used for synthesis of methanol, DME, and FTD. Still, there are CO_2 emissions produced from chemical processes for production of these fuels. The CO_2 emissions are calculated with carbon mass balance in GREET. That is, based on assumed energy conversion efficiencies for these fuels, GREET determines the amount of NG input for a unit of fuel produced. Carbon in NG input minus carbon in the produced fuel would be carbon emitted to the atmosphere. However, for FTD production, there are various products with different carbon contents produced. Without knowing the product mix and carbon content of each product, the carbon mass balance method cannot be used. We use a so-called carbon conversion efficiency (defined as carbon in fuel products divided by carbon in NG input) to calculate CO_2 emissions for FTD production. In particular, we use a carbon conversion efficiency of 72% for FTD production from NG and 65% for FTD production from FG. These values are based on Marshall (1999) and Russell (1999).

Table 4.14 presents CO_2 emissions from production of the fuel fuels. The CO_2 emissions are determined by energy conversion efficiency assumed for each pathway. These values are with the conversion efficiencies presented in Table 4.11. With a new conversion efficiency, GREET automatically calculates new CO_2 emission rates.

The amount of CO_2 emissions from H_2 plants is large. To achieve larger CO_2 reductions by H_2-fueled FCVs, Williams (1996) and Blok et al. (1997) suggested that the CO_2 produced in H_2 plants should be sequestered through injection of the produced CO_2 to depleted NG fields. They maintained that the cost of CO_2 sequestration is minimal — in fact, if the produced CO_2 is

Table 4.14 CO_2 Emissions from Production of Methanol, H_2, DME, and FTD[a]

Fuel	Emissions from Process Fuel Combustion	Emissions from NG Feed Conversion	Total Emissions
Methanol from NG	16,370	-610	15,760
Methanol from FG	17,140	2,740	19,880
Centralized H_2 production	17,740	67,770	85,510
Decentralized H_2 production	19,130	73,020	92,150
DME from NG	180	16,350	16,530
DME from FG	210	20,310	20,520
FTD from NG	20	33,450	33,470
FTD from FG	20	41,830	41,850

[a] Values are in g/10^6 Btu fuel output.

used for enhanced oil and NG recovery, the cost could be offset by the additional NG produced from depleted NG fields. If H_2 is massively produced from NG for motor vehicle applications, and if the United States commits itself to stabilize or to reduce its total GHG emissions, CO_2 from H_2 plants can certainly be sequestered for commercial uses (such as enhanced oil and gas recovery) and for reductions in CO_2 emissions. GREET includes an option that allows users to consider sequestering some of the CO_2 emissions in centralized H_2 plants.

The argument for CO_2 sequestration can be made for FTD, DME, and methanol production as well, although sequestration in H_2 plants is more effective and economical. In GREET calculations for this report, we do not include CO_2 sequestration for any of the four fuels. A user can assume sequestration in GREET.

CO_2 sequestration can have a large effect on GHG emissions of H_2-fueled FCVs. If CO_2 sequestration is assumed for H_2, H_2-fueled FCVs could become almost zero-GHG-emission vehicles.

GREET contains two cycles for LPG production: one for production from crude and the other for production from NG. Users can present energy use and emissions results for each cycle separately, or combine the results of the two cycles together with the split between the two. EIA presents data on production of LPG from NG and crude in the *Petroleum Supply Annual* (EIA 1997b). In general, LPG includes propane, propylene, ethane, butane, and isobutane. Propane is primarily used as a fuel for commercial and transportation applications; the other compounds are primarily used as chemical feedstocks. Thus, in calculating the split of LPG production between crude and NG for transportation applications, data on propane production, not on LPG production, should be used. By using propane production data in EIA's *Petroleum Supply Annual* (EIA 1997b), we estimate that 60% of propane is produced from NG and the remaining 40% from crude.

4.2.6 Potential Steam Co-Generation in Methanol, H_2, DME, and FTD Plants

Production of methanol, H_2, DME, and FTD involves two major processes: syngas generation and fuel synthesis. The syngas generation process is endothermic, and a large amount of high-quality steam is required. The fuel synthesis process is exothermic and is capable of generating low-quality steam. Some of the generated steam can be used to heat feed to reduce energy use during syngas production. Some plants are designed with steam-driven compressors to deliver the required mechanical force. Some plants are designed with a co-generation system to generate electricity from the steam. Other plants are designed to produce steam for export to nearby plants.

In GREET, we designed a feature that allows the excess steam from methanol, H_2, DME, and FTD plants to be exported to nearby plants for use. The amount of steam generated from each plant type is calculated by using the gross conversion efficiency (which accounts for the energy in the steam) and net efficiency (which does not include the energy in the steam). On the basis of data presented in Section 4.2.2, we estimate the conversion efficiency and the amount of steam that could be generated from each plant type (Table 4.15). Comparison of Tables 4.11 and 4.15 shows that plant designs that include steam production have lower net conversion efficiencies than plant designs that do not incorporate steam production.

Table 4.15 shows the amount of steam that could be produced for export. The exported steam can displace steam that would otherwise be produced in conventional steam production systems. We assume that the co-generated steam will replace steam that is produced in boilers fueled by NG. Furthermore, we assume that these steam boilers have an energy conversion efficiency of 80%. Energy and emission credits of the co-generated steam are calculated on the basis of these assumptions within GREET.

Table 4.15 Net Conversion Efficiencies of and Steam Generation in Methanol, H_2, DME, and FTD Plants

Plant Type	Net Conversion Efficiency (%)	Amount of Steam Available for Export (Btu per 10^6 Btu fuel produced)
MeOH	65	111,000
H_2	67	269,000
DME	68	44,000
FTD	53	264,000

Some of the total steam that could be generated from the four plant types would be used for increased operations at the plants that imported the steam. The remaining steam would be used to displace steam production by conventional steam generation systems. The former amount should not be taken into account in calculating energy and emission credits. Without economic simulation of plant operations, we cannot determine the split between increased operations and displaced existing operations for these plants. We assume that 20% of the co-generated steam will be used for increased plant operations.

4.3 Ethanol Production Cycles

GREET includes three ethanol-producing fuel cycles: corn to ethanol, woody biomass to ethanol, and herbaceous biomass to ethanol. Technologies for converting corn to ethanol (e.g., dry and wet milling technologies) are mature and used in large commercial applications at present; technologies for converting biomass (both woody and herbaceous) to ethanol have not been demonstrated commercially. Large-scale, efficient biomass farming for ethanol production also has yet to be demonstrated. So, while the corn-to-ethanol cycle can be treated as a near-term technology option, the other cycles (herbaceous and woody biomass to ethanol) should be treated as long-term options. Most of the assumptions and data sources used in this section are documented in two reports (Wang et al. 1997; Wang et al. 1998).

In the GREET model, the emissions and energy use involved in the production of corn, woody biomass, and herbaceous biomass are calculated on the basis of the amount of fuel and chemicals (fertilizer, herbicides, and insecticides) used per physical unit of product (bushel [bu] for corn, dry ton for biomass, and gallon for ethanol), rather than the energy efficiencies of the production process. So, by inputting the amount of fuel used, the amount of chemicals used, and the amount of energy used to produce chemicals, we can calculate the energy efficiencies for the production of corn, woody biomass, and herbaceous biomass. Direct use of these values (amount of fuel and chemicals used) in the GREET model makes the assumptions more transparent and easier to interpret. Figure 4.1 presents the stages that are included for the three ethanol cycles in GREET 1.5.

4.3.1 Fuel and Chemicals Used for Corn and Biomass Production

Table 4.16 summarizes assumptions regarding energy and chemical use for corn farming included in two studies. The U.S. Department of Agriculture (USDA) study (Shapouri et al. 1995) used the results of the USDA's 1991 Farm Costs and Returns Survey, conducted for nine Midwest corn-growing states. In 1996, statistics show that these states together produced 77% of total U.S. corn. A study by Wang et al. (1997b), commissioned by the Illinois Department of Commerce and Community Affairs, was conducted for four Midwest states. These four states produced 56% of the total U.S. corn in 1996. Wang et al. (1999) conducted a study to estimate farming energy and chemical use for the United States as a whole. We use results from the second study here.

Figure 4.2 shows historical trends of corn productivity (as defined in bushels of corn produced per pound [lb] of fertilizer used) in the past 30 years. The figure shows a clear trend of increasing corn productivity between 1984 and 1994 — the increase is about 30%, or 2.6% annually. On the other hand, between 1965 and 1983, corn productivity was relatively flat. Because of continuous agricultural research and development in such areas as genetic engineering and conservation farming practices (such as precision farming and nontilling

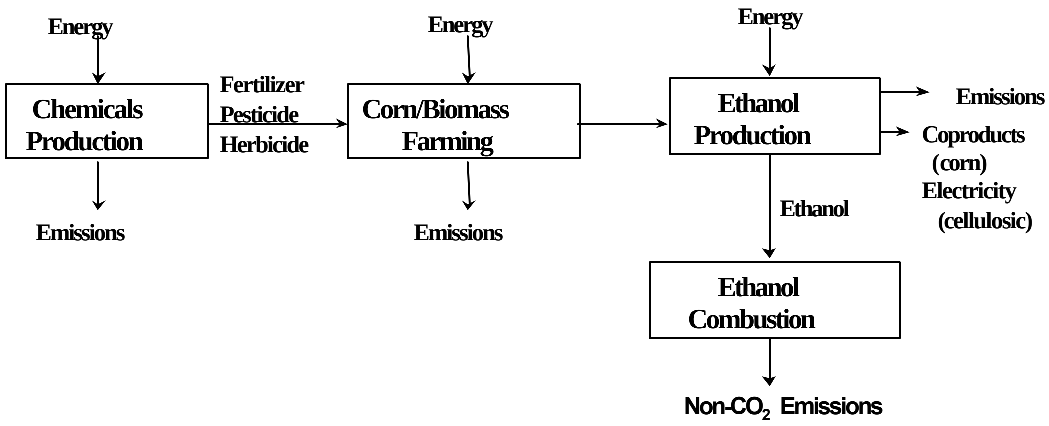

Figure 4.1 Stages Included in Renewable Ethanol Cycles

Table 4.16 Energy and Chemical Use for Corn Farming

Parameter	Shapouri et al. 1995	Wang et al. 1997	Wang et al. 1998	GREET 1.5
Study region	9 Midwest states[a]	4 Midwest states[b]	U.S.[c]	U.S.
Energy use (Btu/bu)[d]	20,620	19,180	21,100	18,990
Farming fuel share (%)				
Diesel	44.9	49.0	49.0	49.0
Gasoline	15.2	16.3	16.3	16.3
LPG	11.2	12.9	12.9	12.9
Electricity	14.9	1.2	1.2	1.2
NG	13.9	20.6	20.6	20.6
Chemical use (g/bu)				
Nitrogen fertilizer	464	476	489	440
P_2O_5 fertilizer	217	173	184	166
K_2O fertilizer	196	206	220	198
Herbicides	14.6	9.5	9.5	9
Insecticides	NA[e]	0.68	0.68	0.68

[a] The nine Midwest states included in the USDA study are Illinois, Indiana, Iowa, Minnesota, Nebraska, Ohio, Michigan, South Dakota, and Wisconsin. In 1996, the nine states produced about 77% of U.S. total corn production.

[b] The four Midwest states included in the study are Illinois, Iowa, Minnesota, and Nebraska. In 1996, the four states produced about 56% of U.S. total corn production.

[c] On the basis of 1996 data for 16 major corn-growing states, which produce 90% of U.S. corn. To reflect improvements between 1996 and 2005 (near-term evaluation year), we reduce energy and chemical use intensity of the 16-state results by 10%.

[d] Farming energy use here includes corn seed growth, fuel use for farming, and energy use for drying corn. The USDA energy use values, which were presented in HHVs, were converted into LHVs here.

[e] Not available.

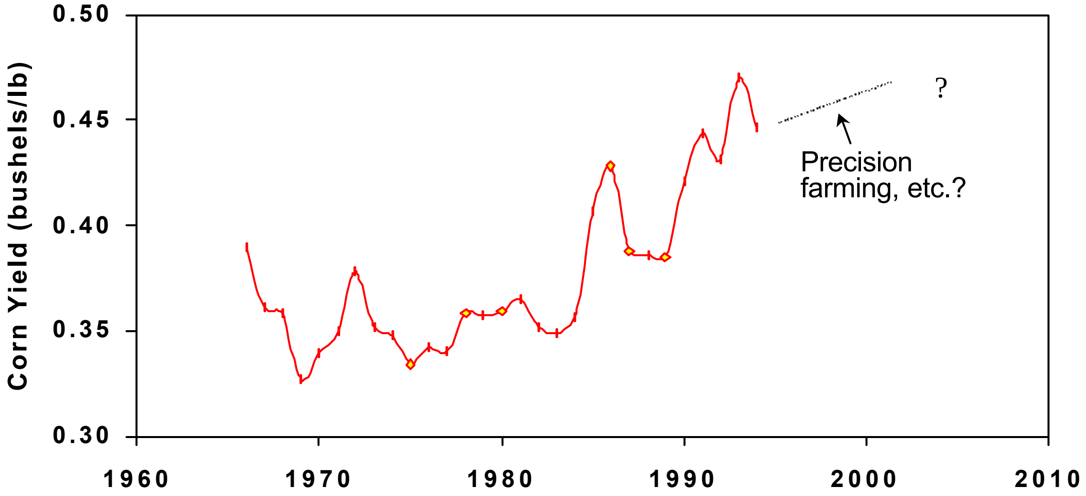

Figure 4.2 Historical Corn Productivity: Bushels of Corn Produced per Pound of Fertilizer Applied (3-year moving average; nitrogen, phosphate, and potash fertilizers are included here, on the basis of data provided by Shapouri [1997])

farming), the amount of energy and chemicals used per bushel of corn produced may continue to decrease in the foreseeable future. To simulate corn ethanol production in future years (such as in 2010), energy and chemical use will be lower than the default values in GREET. Section 6 presents projected energy and chemical use for 2015.

PM emissions are generated during tillage of cornfields. Cowherd et al. (1996) reported a PM_{10} emission rate of 5.7 lb/acre for tillage of agricultural fields. This emission rate is included in GREET for corn farming.

Fertilizer and chemical use figures for biomass farming were provided by Marie Walsh (1998) of Oak Ridge National Laboratory. Input values in GREET 1.5 are presented in Table 4.17.

4.3.2 Energy Use and Emissions of Transporting Corn and Biomass from Farms to Ethanol Plants

Wang et al. (1997b) estimated the energy used to transport Midwest corn from farms to ethanol plants by assuming a two-step transportation process: first in class 6 trucks from farms to collection stacks (a 20-mi round trip, on average), then in class 8a trucks from stacks to the ethanol plants (an 80-mi round trip). A payload of 15,000 lb was assumed for the class 6 haul and 30,000 lb for the class 8a haul. No goods were assumed to be hauled back from ethanol plants to stacks or from stacks to farms. Wang and his colleagues apply fuel economy values of 6 mpg for a class 6 truck and 5.1 mpg for a class 8a truck (gasoline equivalent) to compute haul energy, and of 56 lb per bushel of corn to compute payload volume. Under these assumptions, fully allocated energy use per bushel of corn transported was estimated as 4,081 Btu.

Table 4.17 Energy and Chemical Use for Biomass Farming[a]

Parameter	Woody Biomass (hybrid poplars)	Herbaceous Biomass (switchgrass)
Energy use (in Btu/dry ton)	234,770	217,230
Fuel splits (%)		
Diesel	94.3	92.8
Electricity	5.7	7.2
Chemical use (in g/dry ton)		
Nitrogen fertilizer	709	10,633
P_2O_5 fertilizer	189	142
K_2O fertilizer	331	226
Herbicides	24	28
Insecticides	2	0

[a] From Walsh (1998). The results are based on a yield of 5 dry tons/acre for hybrid poplars and 6 dry tons/acre for switchgrass and a moisture content of 50% for hybrid poplars and 13–15% for switchgrass.

Use of corn from other U.S. regions for ethanol production will certainly increase the transportation distance. The four Midwest states included in the study by Wang et al. (1997b) produce about 56% of total U.S. corn and have more than 90% of the U.S. corn ethanol production capacity. Corn from other U.S. regions will be probably transported to ethanol plants via trucks and rail and over longer distance. To estimate mode split, transportation distance, and transportation energy intensity, we increased the estimated transportation energy use given in Wang et al. (1997b) by 20%. That is, we used a corn transportation energy use of 4,897 Btu/bu of corn transported.

According to Marie Walsh (1998), class 8b trucks with a payload of 17 tons can be used for biomass transportation. Woody biomass has a moisture content of about 50% and switchgrass has a moisture content of about 13–15%. Assuming a one-way transportation distance of 50 mi and a fuel economy of 4.9 mpg for class 8b trucks, we estimated an energy use of 154,200 Btu per wet ton of biomass transported. This translates into 308,400 Btu per dry ton for woody biomass and 179,300 Btu per dry ton for switchgrass. These values are used in GREET.

4.3.3 Energy Use of Manufacturing Fertilizers and Pesticides

In GREET 1.0, energy use and emissions associated with manufacturing fertilizers, herbicides, and pesticides were estimated together with energy use and emissions associated with corn farming and biomass farming. Changes in energy efficiencies of the manufacturing plants for these chemicals sometimes had to be made outside the model; the resultant energy use and emissions were input into the model. In GREET 1.5, a separate sheet is designed to calculate energy use and emissions per gram of chemical produced. The sheet includes three fertilizer types (nitrogenous, phosphoric, and potassic), four herbicides (atrazine, metolachor, acetochlor, and cyanazine — the four major herbicides used for corn farming); and a combination of insecticides for corn farming and one generic insecticide for farming biomass and soybeans.

The nutrients of the three fertilizers are elemental nitrogen (N), phosphate (P_2O_5), and potassium oxide (K_2O [potash]) for nitrogenous, phosphoric, and potassic fertilizers, respectively. Although application rates (in grams per acre [g/acre]) and energy use for fertilizer production (in Btu/g) can be presented either in the amount of all the compounds or the nutrient contained in each fertilizer for each fertilizer type, we use the fertilizer application rate and energy usage rate for nutrients. That is, we present fertilizer use and energy use for grams of nitrogen for nitrogenous fertilizers, grams of P_2O_5 for phosphoric fertilizers, and grams of K_2O for potassium fertilizers. Energy use and the shares of different fuels for production of these chemicals are based on data presented in previous studies. Table 4.18 presents values used in GREET 1.5. Users can change these values in the model to reflect different manufacturing technologies.

Table 4.19 presents energy use and process fuel shares for manufacturing pesticides. The table presents four herbicides that are mainly used for corn farming. The energy use associated with herbicide manufacturing for corn farming is calculated with the energy use of manufacturing each of the four individual herbicides with the application shares of the four. The shares of the four herbicides are estimated to be 31.2% for atrazine, 28.1% for metolachor, 23.6% for acetochlor, and 17.1% for cyanazine. These shares are input into GREET. Atrazine and metolachor are the two main herbicides for soybean farming (discussed below). Between the two, the shares are 36.2% for atrazine and 63.8% for metolachor. These shares are input into GREET to calculate an average energy intensity of herbicide manufacturing for soybean farming. Because no information is available regarding what herbicides will be used for biomass farming, we use the straight average of the energy use for the four herbicides as the energy use value of herbicide manufacturing for biomass farming.

Table 4.18 Energy Use and Fuel Shares for Fertilizer Manufacture

Parameter	N	P_2O_5	K_2O
Energy use (Btu/lb)			
Shapouri et al. 1995[a]	22,159	4,175	1,245
Wang et al. 1997b	21,111	4,903	2,270
Bhat et al. 1994	23,893	1,947	2,067
Mudahar and Hignett (1987a,b)[b]	33,641	7,515	5,900
GREET 1.5: per lb (per g)	21,110 (46.5)	4,900 (10.8)	2,270 (5.0)
Fuel Share (%)[c]			
Diesel	0	27	31
Natural gas	90	26	27
Electricity	10	47	42

[a] Data in Shapouri et al. were based on the 1992 survey by the Fertilizer Institute. The energy use was an HHV-based value.

[b] The values by Mudahar et al. were based on data from the early 1980s. The energy use values explicitly included packaging, transportation, and application as well as production. Other studies may implicitly include energy use for packaging and transportation. Energy use required for application might be included in farming activities in other studies. The values are HHV based.

[c] Based on Shapouri et al. (1995).

Table 4.19 Energy Use and Fuel Shares for Pesticide Manufacture

	Herbicides				Insecticides	
Parameter	**Atrazine**	**Metolachor**	**Acetochlor**	**Cyanazine**	**Other Crops**	**Corn**
Energy use (Btu/lb)						
Wang et al. 1997b	81,720	118,949	119,856	86,714	NE[a]	104,420
Swanton et al. 1996	81,811	158,446	NE	NE	NE	NE
Shapouri et al. 1995	NE	NE	NE	NE	158,464	NE
Bhat et al. 1994	81,825	118,862	NE	86,563	NE	NE
Green 1987	82,687	119,723	NE	87,423	NE	NE
GREET 1.5: per lb	82,000	119,000	120,000	86,850	117,000	105,400
(per g)	(180.6)	(262.1)	(264.3)	(191.3)	(257.7)	(231.3)
Fuel share (%)						
Diesel	30%	30%	30%	30%	60%	60%
Residual oil	30%	30%	30%	30%	0%	0%
NG	23%	23%	23%	23%	23%	23%
Electricity	17%	17%	17%	17%	17%	17%

[a] NE = not estimated.

We estimated the energy use of insecticide manufacture for farming corn and other crops. By using data presented in the previous studies, we estimated process fuel splits for herbicide and insecticide manufacturing.

4.3.4 Energy Use of Transporting Fertilizers and Pesticides from Manufacturing Plants to Farms

Transportation of fertilizers and pesticides from manufacturing plants to farms occurs in three steps: (1) from manufacturing plants to bulk distribution centers, (2) from distribution centers to mixers, and (3) from mixers to farms. Wang et al. (1997b) made detailed assumptions in estimating energy use during chemical transportation. Table 4.20 presents these assumptions regarding travel distance, transportation mode, and transportation energy intensity for each step. In steps 2 and 3, empty backhaul (i.e., round-trip distance) is included in the energy calculation, while for step 1, the backhaul is assumed to be an unrelated revenue movement. The high energy values for plants to bulk centers (step 1) is attributable to long-distance travel, while that for mixers to farms (step 3) is caused by the relatively small payload for class 6 trucks.

For transportation between manufacturing plants and bulk distribution centers, both barges and rails are used. Energy use by barge is estimated to be 374 Btu/ton-mi, the national average for 1995 (Davis and McFarlin 1997). Emission factors for barges fueled with residual oil or bunker fuel are 27 lb of SO_x, 100 lb of CO, 50 lb of HC, and 280 lb of NO_x per 10^3 gal of fuel (EPA 1991a). Energy use by rail is estimated to 372 Btu/ton-mil, the national average in 1995 (Davis and McFarlin 1997). Assuming locomotives are diesel-fueled, emission factors are estimated at 25 lb of PM, 130 lb of CO, 94 lb of HC, and 370 lb of NO_x per 10^3 gal of diesel (EPA 1991a).

Table 4.20 Key Assumptions and Results of Energy Use for Transportation of Chemicals

Parameter	Step 1: Plant to Center	Step 2: Center to Mixer	Step 3: Mixer to Farm
Travel distance (mi/one way)	1,060/520	50	30
Transportation mode	barge/rail	Class 8b truck	Class 6 truck
Energy use: Btu/ton (Btu/g)	294,940 (0.325)	105,620 (0.116)	220,000 (0.242)

Assuming a 50/50 tonnage split between barge and rail transportation, the average energy use per ton of chemicals transported between plants and bulk centers is estimated to be 294,940 Btu/ton ([1,060 × 374 + 520 × 372] ÷ 2). Emissions are calculated with the energy use rate and the emission factors in g/10^6 Btu of fuel used.

We assumed that class 8b trucks (greater than 33,000 lb gross vehicle weight [GVW]) are used to transport chemicals from bulk distribution centers to mixers. A typical class 8b tractor/trailer combination with full payload has a GVW of 80,000 lb; the tractor weighs 12,000–15,000 lb, and the trailer is around 10,000 lb. Thus, the maximum payload is 55,000–58,000 lb, and a typical payload is 40,000–50,000 lb. We assume a payload of 45,000 lb. The fuel economy and emissions of the truck are estimated by using the GREET model. In calculating energy use and emissions per ton of chemicals transported, a round-trip travel distance of 100 mi is used. That is, no payload is assumed for the trip from the mixers to the bulk centers. At a fuel economy of 4.86 mpg (gasoline equivalent gallons; estimated by using GREET), transportation energy intensity is estimated at 105,624 Btu/ton.

Class 6 trucks (19,500–26,000 lb GVW) are assumed to provide chemical transport from mixers to farms. A typical class 6 truck has a truck weight of 8,500–10,000 lb. Thus, the maximum payload is 11,000–16,000 lb. We assume a payload of 10,000 lb. Per-ton energy use and emissions are calculated on the basis of a round-trip distance of 60 mi. That is, no payload is assumed for the trip from farms to mixers. At a fuel economy of 6 mpg (gasoline equivalent), transportation energy intensity is estimated at 220,000 Btu/ton.

4.3.5 Ethanol Production

Production of Ethanol from Corn. Ethanol plants are the largest fossil-energy-consuming process in the entire corn-to-ethanol fuel cycle. Ethanol production research and development efforts in the last two decades have concentrated on increasing ethanol yield and reducing plant energy use to decrease the costs for process fuels in ethanol plants. Advanced ethanol plant designs employ energy conservation technologies such as molecular sieve dehydration and cogeneration of steam and electricity. As a result, newly built ethanol plants are more energy efficient than plants that have been operating for many years. On the other hand, energy use in existing ethanol plants has also been reduced through integration of more energy-efficient processes. Wang et al. (1997b) collected information regarding recent trends in ethanol plant energy use from ethanol plant designers and operators. By using the information collected, they estimated total energy use and the split of energy use between ethanol production and coproduct production.

In our analysis, we have included both dry and wet milling ethanol plants. With input data for each type, GREET can estimate fuel-cycle energy use and emissions for the two types separately. Wet milling plants produce ethanol from corn starch and produce high-fructose corn syrup, glucose, gluten feed, and gluten meal as coproducts. We assume that all the starch derived from corn in wet milling plants is targeted for ethanol conversion. Production of high-fructose corn syrup, a high-value end product derived from corn kernel sugars, takes place in a different process stream and is therefore not included as an ethanol coproduct. Our research shows that most plants include molecular sieve dehydration and that about half of ethanol plants employ cogeneration systems.

Dry milling plants are designed exclusively for ethanol production. They are much smaller than milling plants. In these plants, ethanol is produced from corn starch, and other constituents of the corn kernel are produced together and referred to as distillers' dried grains and solubles (DDGS).

Table 4.21 presents a summary of total energy use and process fuel shares for corn farming products and ethanol production and coproduct production in wet and dry milling plants, respectively. The farming allocation is based on the relative market value of ethanol and nonethanol products, while the milling energy allocation is based on the process energy share. The table shows that *total* energy use per gallon of ethanol, on a current capacity-weighted basis, is similar for dry and wet milling.

For comparison, Figure 4.3 shows historical data on energy use in corn ethanol plants. As the figure shows, energy use has been reduced between the 1970s and the 1990s. This is especially true for dry milling plants.

Table 4.21 Energy Use and Process Fuel Shares for Corn-to-Ethanol Production at Ethanol Plants[a]

Parameter	Dry Milling	Wet Milling
Total energy use before allocation (Btu/gal):		
Current (1997)	41,400	40,300
Near future (2005)	36,900	34,000
Process fuel share: current (%)		
Natural gas	47	20
Coal	47	80
Electricity	6	0
Process fuel share: near future (%)		
Natural gas	50	20
Coal	50	80
Electricity	0	0

[a] From Wang et al. (1997b).

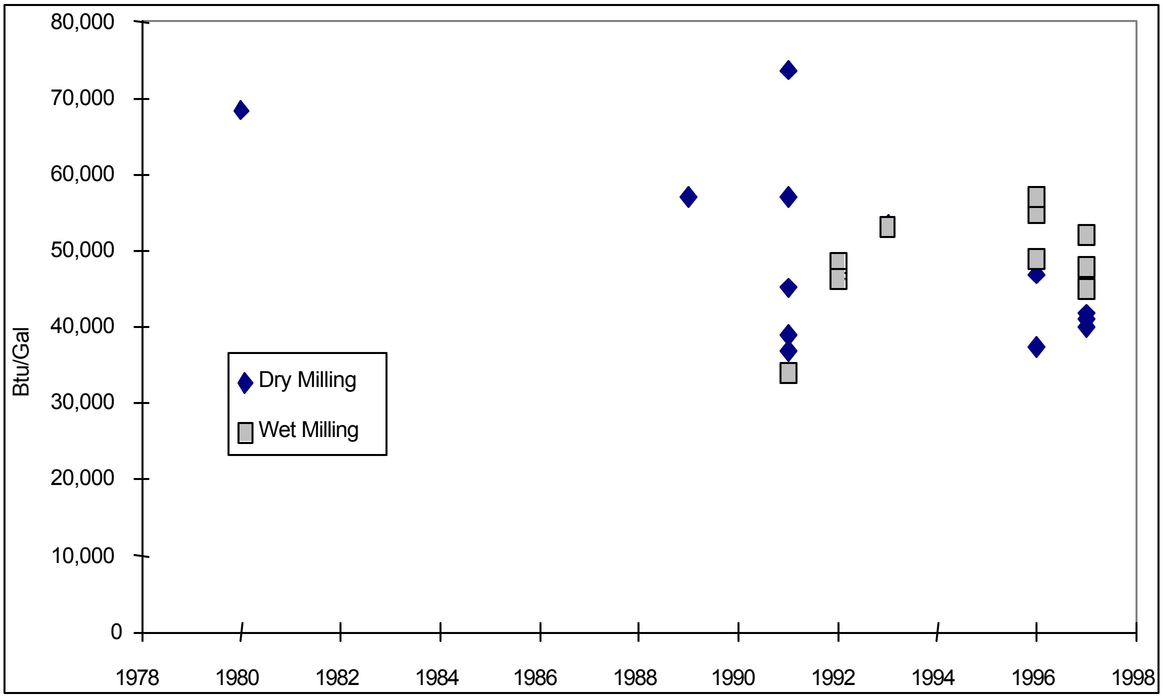

Figure 4.3 Historical Estimates of Energy Use in Ethanol Plants

Established wet milling plants are fueled primarily with coal, often supplemented by NG, as described below. If cogeneration systems are employed, plants can usually generate enough electricity for their own consumption. Otherwise, ethanol plants obtain electricity from the supply grid. Even if coal is burned to generate steam and electricity, NG is often used in wet milling plants for direct drying of products because of (1) the high heat demand and (2) superior economics of NG for this purpose. On the basis of our contacts with industry representatives, we assume that, for wet milling plants, 80% of total thermal energy required is supplied by coal and the remaining 20% by NG. Because dry milling plants are much smaller on average than wet milling plants, their cost savings from switching from NG to coal should be small. We expect that most dry milling plants are fueled by NG. However, we conservatively assume that 50% of the total thermal energy required in dry milling plants is supplied by NG and the remaining 50% by coal.

Restrictive environmental regulations precluding new coal burning permits in many areas have led to new ethanol plant designs that primarily incorporate NG firing as the process fuel. Use of NG in ethanol plants results in fewer total CO_2 emissions from ethanol plants. We have included a case in our sensitivity analysis in which we assume that the thermal energy for all ethanol plants is provided by NG. Electricity use in ethanol plants accounts for 9–15% of their total energy consumption. Most established wet milling ethanol plants are equipped with cogeneration systems to produce both steam and electricity. In contrast, many dry milling plants purchase electricity from the power grid. Use of cogeneration systems can help reduce plant energy use by as much as 30% (Ho 1989). In general, a reduction of 10% in energy use is readily achieved by use of cogeneration systems (Grabowski 1997). If all plants employed cogeneration systems, the total energy consumption in ethanol plants would be 40,400 Btu/gal for dry milling plants and 40,300 Btu/gal for wet milling plants. In our base case analysis, we assume that 50% of dry milling and 100% of wet milling plants employ cogeneration systems but that in the future, cogeneration use will be 100% in all mills.

Calculated emissions and energy consumption per bushel of corn are converted into emissions and energy consumption per 10^6 Btu of energy produced. For this conversion, we use 2.6 gal of ethanol per bushel of corn for dry milling ethanol plants and 2.5 gal of ethanol per bushel of corn for wet milling plants. These values are for the near term. The long-term values are presented in Section 6.

Ethanol Coproduct Energy and Emission Credits. Besides ethanol, corn-ethanol plants produce a variety of coproducts. While dry milling plants produce only distillers' grains and solubles (DGS), wet mills produce corn gluten feed, corn gluten meal, and corn oil, together with ethanol. Most previous studies allocated an emissions and energy use charge between ethanol and its coproducts by using one of five attribution methods for both corn farming and ethanol production: (1) weight-based, (2) energy content, (3) product displacement, (4) market value, or (5) process energy approach.

The weight-based approach may be reasonable for coproducts if one assumes that the coproducts can replace the current products on a pound-to-pound basis. However, weight, which is used in this approach, has little meaning for most coproducts.

The energy content approach is reasonable for ethanol but not for coproducts. Coproducts have commercial value not because of their energy content but because of their nutrients and other properties.

The product displacement approach is the theoretically correct way to determine emissions and energy use of coproducts. However, it is difficult to accurately identify displaced products and determine the displacement ratio between the ethanol coproducts and displaced products. Also, an increase in corn meal production because of ethanol production may result in an increase in animal feed production rather than in a decrease in production of displaced products. The majority of animal feeds produced from wet milling ethanol plants in the United States are exported to other countries. The potential marginal changes in the economy of those countries as a result of imported corn gluten meals and feed are not clear.

The market value approach implies that emissions and energy use are allocated on the basis of the contribution of each product to the economy. This approach is intended to treat each product fairly according to its economic value. One problem is that the approach is subject to fluctuations in the market prices of ethanol and coproducts. To address this problem, average prices over a period of time need to be used in calculating the market value of each product.

The process energy-based approach applies only to ethanol plants. With this approach, production processes of ethanol plants are determined as ethanol-related and nonethanol-related. Energy use and emissions of ethanol-related processes are allocated to ethanol production. Those of non-ethanol-related processes are allocated to coproducts. On the other hand, to allocate energy use and emissions from corn farming, other approaches still need to be used. In

Wang et al. (1997b), the market-value-based approach was used to allocate corn farming energy use and emissions between ethanol and its coproducts.

Use of different allocation approaches can have significant impacts on calculated corn ethanol fuel-cycle energy use and emissions. Table 4.22 shows allocation ratios based on the different approaches.

Both the displacement approach and the market value approach are presented in GREET 1.5. The user can select one of the two approaches; we used the displacement approach as the default approach in our analysis.

The market value-based approach in GREET 1.5 is actually a hybrid approach in which energy use and emissions of corn farming are allocated between ethanol and its coproducts according to market values of each. For example, for dry milling plants, which produce DGS, the market value split is 24% for DGS and 76% for ethanol. For wet milling plants, the market value split is 30% for corn gluten meal, corn gluten feed, and corn oil and 70% for ethanol. For ethanol plants, we use the process energy-based approach to allocate total energy use and emissions between ethanol and its coproducts. That is, we allocate 33% of energy use and emissions to coproducts in dry milling plants and 31% to coproducts in wet milling ethanol plants.

In GREET 1.5, we use the displacement method to derive coproduct energy and emission credits. First, we estimate the amount of coproducts produced in an ethanol plant. Second, we identify the products to be displaced by the coproducts. Third, we determine displacement *ratios* between coproducts and displaced products. Finally, we estimate energy use and emissions for producing the displaced products. These steps are integral to the GREET model.

Table 4.22 Comparison of Energy Use and Emissions Allocation between Ethanol and Coproducts in Corn Ethanol Plants

Energy and Emissions Allocation (%)				
Ethanol	**Coproducts**	**Basis**	**Method**	**Source**
57	43	Market value	Wet milling	Morris and Ahmed 1992
70	30	Market value	Wet milling	Shapouri et al. 1995
76	24	Market value	Dry milling	Shapouri et al. 1995
57	43	Energy content	Wet milling	Shapouri et al. 1995
61	39	Energy content	Dry milling	Shapouri et al. 1995
48	52	Output weight basis	Wet milling	Shapouri et al. 1995
49	51	Output weight basis	Dry milling	Shapouri et al. 1995
81	19	Displacement value	Wet milling	Shapouri et al. 1995
82	18	Displacement value	Dry milling	Shapouri et al. 1995
81	19	Displacement value	Dry milling	Delucchi 1993
69	31	Process energy basis	Wet milling	Wang et al. 1997b
66	34	Process energy basis	Dry milling	Wang et al. 1997b

Tables 4.23 and 4.24 present production rates of coproducts in ethanol plants and displacement ratios between coproducts and the products they displace. The values are based on data provided during a workshop at Argonne National Laboratory by a group of experts on animal feeds (Berger 1998; Klopfenstein 1998; Madson 1998; Trenkle 1998).

Table 4.23 Coproduct Production Rates in Ethanol Plants[a]

Coproduct	Bone-Dry lb/bu	Bone-Dry lb/gal
Dry milling		
DGS	15.8	6.09
Wet milling		
Corn gluten meal	2.6	1.04
Corn gluten feed	11.2	4.48
Corn oil	2.08	0.83

[a] The values are based on ethanol yields of 2.6 and 2.5 gal/bu of corn for dry and wet milling plants, respectively.

Coproduct production, as presented in Table 4.23, is affected by ethanol yield per bushel of corn, simply because of the mass balance between ethanol and the coproducts. On the basis of data collected from the 1998 Argonne workshop, we estimate the amount of DGS from dry milling plants by using the following equation:

$$\text{DGS} = 44.658 - 11.083 \times \text{EtOH Yield} \qquad [4.2]$$

where

DGS = DGS yield in lb/bu of corn input, and
EtOH Yield = Ethanol yield in gal/bu of corn input.

For the three coproducts from wet milling plants, we could not derive equations to calculate the yields. We estimate the following yields: 2.6 lb of corn gluten meal, 11.2 lb of corn gluten feed, and 2.08 lb of corn oil per bushel of corn input at the ethanol yield of 2.6 gal/bu of corn. We assume these rates remain same with different ethanol yields and calculate per-gallon yields from the per-bushel yields by using different ethanol yield assumptions. Per-gallon yields for DGS, corn gluten meal, corn gluten feed, and corn oil are calculated within the GREET model.

Table 4.24 Coproduct Displacement Ratios[a]

Coproduct	Ratio
DGS	
Corn	1.077
Soybean meal	0.823
Corn gluten meal	
Corn	1.529
Nitrogen in urea	0.023
Corn gluten feed	
Corn	1.000
Nitrogen in urea	0.015
Corn oil	
Soybean oil	1.000

[a] Values are in pound of displaced product per pound of coproduct.

The displacement ratios in Table 4.24 do not incorporate the effects of the recent price decrease in animal feeds caused by ethanol coproducts. Additional coproduct production will likely lead to decreases in feed prices, which can in turn increase meat production. That is, of the total quantity of coproducts produced in ethanol plants, some will displace animal feed and some will be employed in production of meats. Using the USDA's simulation results (Price et al. 1998), we estimated that a 1% decrease in animal feed supply results in a 0.151% decrease in meat production, implying that 15.1% of coproduct production will likely go toward new production of meats. The small change in meat production that results from the change in feed supply is partly caused by the fact that corn-based animal feed is usually used for finishing feeding of animals such as cattle and dairy cows. The small amount for new production is not accounted for in this analysis when estimating energy and emission credits of coproducts because it does not displace existing animal feed production.

Production of Ethanol from Biomass. At cellulosic ethanol plants, the unfermentable biomass components, primarily lignin, can be used to generate steam (needed in ethanol plants) and electricity in cogeneration systems. Recent simulations of cellulosic ethanol production by NREL indicated an ethanol yield of 76 gal per dry ton of hardwood biomass for ethanol plants that will be in operation around the year 2005 (Wooley 1998). Such ethanol plants consume 2,719 Btu of diesel fuel and generate 1.73 kWh of electricity per gallon of ethanol produced. For cellulosic ethanol plants operating in 2010, the simulations indicated an ethanol yield of 98 gal per dry ton of hardwood biomass. The plants will consume 2,719 Btu of diesel fuel and generate 0.56 kWh of electricity per gallon of ethanol produced. Table 4.25 presents the assumptions used in our analysis.

Table 4.25 Feedstock Requirements, Energy Use, and Electricity Generation Credits in Cellulosic Ethanol Plants

	Woody Cellulosic Plant[a]		Herbaceous Cellulosic Plant[b]	
Parameter	**Near-Future (2003)**	**Future (2010)**	**Near-Future (2003)**	**Future (2010)**
EtOH yield (gal/dry ton of biomass)	76	98	80	103
Diesel use (Btu/gal of EtOH)	2,719	2,719	2,719	2,719
Electricity credit (kWh/gal of EtOH)	1.73	0.56	0.865	0.28

[a] Based on data in NREL et al. (1991).

[b] Values for herbaceous cellulosic plants were estimated from the values for woody cellulosic plants and the differences between woody and herbaceous plants that were estimated from data in NREL et al. (1991).

While combustion of lignin undoubtedly produces CO_2 emissions, these emissions are taken up from the atmosphere by the photosynthesis process during biomass growth. So CO_2 emissions from lignin combustion at ethanol plants were treated as zero. For the same reason, CO_2 emissions from ethanol combustion in ethanol vehicles were treated as zero.

Energy Use and Emissions for Electricity Credits in Cellulosic Ethanol Plants. In cellulosic ethanol plants, combustion of lignin through co-generation facilities generates electricity and the steam required for ethanol production. Table 4.25 lists the credits for excess electricity generated by cellulosic ethanol plants; these credits were estimated on the basis of recent NREL simulations (Wooley 1998). We assumed that the excess electricity generated in cellulosic ethanol plants is exported to the electric supply grid to offset production by electric power plants. Emissions and energy credits for the generated electricity are therefore calculated by taking into account the amount of electricity generated by the cellulosic ethanol plant and deducting the emissions associated with the (estimated) amount of electricity that would otherwise have been generated by electric power plants.

Emissions and energy credits for the generated electricity are a key factor in determining fuel-cycle energy and emissions results for cellulosic ethanol. Calculation of the emissions and energy credits depends on the way in which the researchers address two key questions. First, of the total amount of electricity generated at cellulosic ethanol plants, how much will be used to displace electricity generated by electric power plants and how much will be used to meet the increased demand for electricity induced by cellulosic ethanol electricity through its price effect? We established a case in which only half of the generated electricity was considered for displacement of electricity generated by electric power plants, and the other half was used to meet the increased demand for electricity. Second, what electric power plants will be displaced by the electricity generated in cellulosic ethanol plants? Determining the marginal electric power plants to be displaced requires detailed simulation of future electricity supply in major U.S. regions. We assumed that cellulosic ethanol electricity will displace electric generation on the basis of the U.S. average generation mix.

Other Issues. Conversion of corn starch to ethanol produces excess CO_2 emissions. Because the CO_2 generated is from the atmosphere during the photosynthesis process, it should not be classified as CO_2 emissions. However, if the generated CO_2 emissions are collected and sold (as a few corn ethanol plants do), the CO_2 product would replace CO_2 production from some other conventional processes. In this case, emission credits from the offset CO_2 production should be taken into account. In GREET 1.5, we assume that the generated CO_2 is not collected.

In this study, we assume that lignin is burned in cellulosic ethanol plants to provide steam needed for ethanol production and electricity. While combustion of lignin undoubtedly produces CO_2 emissions, these emissions come from the atmosphere through the photosynthesis process for biomass growth. Thus, the CO_2 emissions from biomass combustion are treated as zero in the GREET model. For the same reason, the CO_2 emissions from ethanol combustion in ethanol vehicles are treated as zero.

4.3.6 N_2O and NO_x Emissions from Nitrification and Denitrification of Nitrogen Fertilizer

Nitrogen fertilizer (N-fertilizer) that is applied to cornfields is (1) extracted by corn plants as a plant nutrient, (2) absorbed (chemically bound) into soil organic materials, and (3) entrapped in soil aggregates (chemically unbound). The chemically unbound nitrogen is then (1) transformed and emitted as N_2O through microbial nitrification and denitrification, (2) volatilized as nitrate (NH_3 [ammonia]), and (3) leached as NH_3 from soil to streams and groundwater via surface runoff and subsurface drainage systems. The majority of N-fertilizer left in soil stabilizes in nonmobile organic form (Stevens 1997). Some of the nitrogen in leached nitrate (nitrate-N) eventually re-bonds as N_2O and migrates to the atmosphere. For our estimate, we include both direct N_2O emissions from soil and those from leached nitrate-N. The N_2O emission rate, expressed in GREET as the percentage of nitrogen in fertilizer that becomes the nitrogen in N_2O (N_2O-N), is determined by such factors as soil characteristics, fertilizer types, and variety of vegetation. In addition, the amount of N-fertilizer leached as nitrate is determined by such factors as soil type (especially sand content), hydrogeology, and depth of water table.

Wang et al. (1997b) reviewed numerous studies on fertilizer-induced N_2O emissions from cornfields and established an extensive database of results from about 30 of these studies conducted during the period 1978–1997. Because the focus was on N_2O emissions from cornfields in the U.S. Midwest, Wang and his colleagues chose as most appropriate the highly reliable data regarding N_2O emissions from both crop rotation systems (corn after soybeans) and continuous corn systems. They calculated fertilizer-induced N_2O emissions from background emissions by subtracting emissions of control fields (where no N-fertilizer is applied) from the total emissions of cornfields where fertilizers are applied. They estimated an average cornfield N_2O emission rate (expressed as percentage of N-fertilizer converted to N_2O-N) of 1.22% — all data fell in a range of 0–3.2% (most were within 1.0–1.8%).

N-fertilizer lost through leaching is in the form of NO_3^- — the mobile form of nitrogen. This nitrate in water is converted to N_2O primarily through microbial denitrification, and up to 1% of initial nitrate nitrogen undergoes denitrification and emission as N_2O-N (Qian et al. 1997). Thus, to estimate N_2O-N emissions from N-fertilizer-derived NO_3^- leached into the drainage system, runoff streams, and groundwater, we used 1% as the conversion factor for transformation of nitrate nitrogen to N_2O-N.

To estimate the amount of nitrate from N-fertilizer in surface runoff, subsurface drainage systems, and groundwater, Wang et al. (1997b) reviewed nine directly relevant studies and derived an average rate of 24% for conversion of total fertilizer nitrogen to nitrate nitrogen (NO_3^--N) through leaching. Given the assumed conversion factor of 1% from nitrate to N_2O emissions, Wang and his colleagues estimated a rate of 0.24% of N_2O emissions due to leaching. Summing soil direct emissions and leaching yields a total N_2O emission rate of 1.5%, the value we use in GREET.

The N_2O emissions estimates are uncertain for several reasons. First, some of the studies reviewed did not include control fields where background N_2O emissions could be measured. Nitrogen deposition with precipitation is a known source of background N_2O emissions. Nitrogen deposited with precipitation was reported in the studies as ranging from 7 to 12 kilograms of nitrogen per hectare (kg N/ha) (Baker and Johnson 1981; Johnson and Baker 1984), a range equal to 4–7% of nitrogen fertilizer applied at a rate of 170 kg N/ha.

Second, none of the studies reviewed by Wang et al. measured *both* direct soil N_2O emissions and nitrogen loss through leaching. There is a balance between leaching and direct soil emissions. That is, with a fixed amount of fertilizer input, an increase in direct N_2O emissions from soil may imply decreased nitrogen loss through leaching, and vice versa. Measurement of emissions from both sources in a single field would address the balance issue.

Third, the rate of microbial denitrification activity is much less intensive in a river than in groundwater. The nitrate concentration is diluted once the stream from runoff or from a drainage system enters a river. Furthermore, under natural groundwater conditions, conversion of nitrate is not likely to be complete, but in the absence of data on this issue, we have assumed that the NO_3^--N that results from leaching is completely denitrified.

Fourth, the solubility of N_2O in water is very high when compared to that of other inorganic gases. The solubility of N_2O is 56 times higher than that of N_2 and 27 times higher than that of O_2. At some reported concentrations, most N_2O in water is likely to remain in aqueous form, rather than converting to a gas for release to the atmosphere. Finally, differences in N_2O measurement methods among the studies may explain some of the variation in reported N_2O emissions (Christensen et al. 1996).

For nitrogen oxide (NO) (the majority of NO_x emissions) emissions, we use the emission rate of 0.79% of N-fertilizer, which was used by Delucchi (1993).

Production of woody and herbaceous biomass requires little soil disturbance and no irrigation, which tends to reduce N_2O and NO emissions from nitrification and denitrification of N-fertilizer. We use an emission rate of 1.3% for N_2O and 0.65% for NO for biomass production.

4.3.7 CO_2 Emissions or Sequestration from Potential Land Use Changes for Ethanol Production

Corn Farming. The United States now produces about 1.5 billion gallons of corn ethanol annually — a total that consumes about 6% of annual domestic corn production. A substantial increase in ethanol production will require a larger amount of corn available for ethanol production. The additional corn could come from (1) increased corn production through increased yield per acre; (2) reduced U.S. corn and corn product exports to other countries; (3) reduced corn consumption by other U.S. domestic sources of demand (such as for animal feeds); (4) farming on idled cropland and/or pastureland; and/or (5) switching cropland from other crops such as soybeans to corn. Increased yield per acre could be accomplished by genetic engineering of corn and/or by adoption of more efficient farming methods, currently described as “precision farming.” If land use patterns are changed by increased ethanol production, a different profile of CO_2 emissions can be expected. Biomass production per unit of land area is generally different for different crops and vegetation. Growing different crops and vegetation can also change the carbon content of land.

To estimate potential land use changes, the USDA’s Office of Energy Policy and New Uses simulated the changes in production and consumption of major crops that would be caused by a selected, presumed change in corn ethanol production (Price et al. 1998). The USDA's simulation was based on complex supply and demand linkages in the agricultural sector, and included price effects that would result from diverting the specified amount of corn to ethanol and ethanol coproduct production. The simulation was conducted on the basis of an assumption that the amount of corn used for ethanol production would increase by 50 million bu/yr beginning in 1998. In the study, the corn increment to be diverted to ethanol production was 650 million bu/yr by 2010, a demand that would double ethanol production to over 3 billion gal/yr.

The USDA's simulation included changes in acres planted for corn, sorghum, barley, oats, wheat, soybeans, rice, and cotton. The simulation results showed a net increase in planted land of 97,400 acres, on average, between 1998 and 2010. In our analysis, we assumed that these additional planted acres are from idled crop and/or pastureland (USDA's simulations did not identify the source for the additional acreage). Delucchi (1998) estimated a CO_2 emission rate of 204,000 g/acre for cornfields converted from idled cropland or pastureland. Thus, the total amount of CO_2 emissions from the 97,400 acres of additional land is 20 million kg/yr. The USDA's simulation assumed that an annual average of 350 million bu of corn would be converted to ethanol. On the basis of these data, we computed a domestic (U.S.) CO_2 emissions rate (due to land use change) of 57 g/bu of corn used in ethanol production.

The USDA simulation showed that increased U.S. ethanol production would reduce domestic corn exports to other countries. On the basis of USDA simulation results, we estimated that the net reduction in U.S. grain exports will be equivalent to about 694 million lb of protein a year. The USDA simulations did not include changes in crop supply and demand in grain-importing countries and grain-exporting countries other than the United States responding to the reduced U.S. grain exports. It is likely that grain-importing countries will experience increased costs for grain protein, which will reduce demand. These nations, together with other grain-exporting countries, will also likely increase their production in response to the higher prices caused by the reduced U.S. grain export. We had no basis for specifying how much of the 694-million-lb protein deficit could be made up by reduced demand in grain-importing countries and how much by increased production in both grain-importing and other grain-exporting countries. In our analysis, we simply assumed that farming new or currently idled land in those countries will make up half of the protein deficit. In other words, we assumed that increased planting makes up half of the import reduction and reduced consumer demand makes up the other half. By using this assumption, we estimated that grain-importing and other grain-exporting countries will increase their own production by 347 million lb of grain-based protein in new lands per year — equivalent to 62.8 million bu of corn in protein equivalents.

We used corn production as a surrogate to calculate emissions of CO_2 caused by the change in land use required to produce the 62.8 million bu of corn-equivalent protein. We assumed a corn yield of 110 bu per planted acre in grain-importing countries (by comparison, U.S. average corn yield is now about 120 and 125 bu per planted and harvested acre, respectively). We estimated that annual production of 62.8 million bu of corn would require a total of 570,900 acres of new land. We further assumed that the new land would be some type of pastureland. Using the CO_2 emissions rate developed by Delucchi for a change from pastureland to cornfield (204,000 g/acre), we estimated a total CO_2 emissions loading of 117 million kg/yr. We allocated this amount to the 350 million bu of corn used annually for the new U.S. ethanol production. This calculation results in a rate of 333 g of CO_2 emissions attributable to potential land use change in grain-importing countries per bushel of corn used in U.S. ethanol production.

In summary, we estimated a net CO_2 emissions rate of 390 (333 + 57) g/bu of corn from potential land use changes in both the United States and in grain-importing countries. Our fuel-cycle analysis showed that this amount of CO_2 accounts for only about 1.5% of the total fuel-cycle GHG emissions associated with E85.

Biomass Farming. At present, no biomass farms exist for cellulosic ethanol production. If mass-scale production of cellulosic ethanol occurs in the future, land will need to be cultivated for biomass farming. In the United States, some land now idle or used as pastureland will likely be cultivated for biomass farming. Cultivating fast-growing trees such as hybrid populars and switchgrass will certainly have land use impacts. The amount of aboveground standing biomass, the amount of underground biomass (i.e., roots), and the organic carbon content of the soil will all likely increase, and these changes will lead to CO_2 sequestration, in addition to the amount of carbon contained in the biomass harvested for cellulosic ethanol production. Delucchi (1998) estimates that the CO_2 sequestration rate caused by land use changes is 225,000 g/dry ton of woody biomass and 97,000 g/dry ton of grass harvested. We use these sequestration rates in GREET.

4.3.8 Ethanol Transportation, Storage, and Distribution

We assume an energy efficiency of 97.7% for ethanol T&S&D. This value is based on past studies and efficiencies for T&S&D of other liquid fuels. We further assume that ethanol is moved by railroad tankers, barges, and trucks primarily fueled with diesel fuels.

4.4 Biodiesel Production

Methyl or ethyl esters that are produced from vegetable oils and animal fats are commonly called biodiesel. Biodiesel is an attractive alternative fuel to reduce emissions from compression-ignition (CI) engines using diesel. Because biodiesel is produced from renewable sources, its use helps reduce petroleum use in diesel motor vehicles. Biodiesel can be produced through the transesterification process from natural vegetable oils such as soy oil, cotton oil, and rape oil or from cooked oil and animal fats. In Europe, biodiesel is mainly produced from rapeseed, while in the United States, it is mainly produced from soybeans. GREET includes the soybean-to-biodiesel fuel cycle.

The soybean-to-biodiesel cycle includes soybean farming, soybean transportation to soy oil plants, soy oil production, tranesterification of soy oil to biodiesel, transportation of biodiesel to bulk terminals (where it is blended with petroleum diesel), distribution of the biodiesel blend to service stations, and vehicular combustion of the biodiesel blend. Data and assumptions for each of the stages are presented in the following sections.

4.4.1 Soybean Farming

Table 4.26 presents data regarding U.S. soybean production and use. The table shows that in 1996, the United States produced a total of 2.177×10^6 bu of soybean. Of that total, about 37% was exported. In addition, 20% of domestically produced soy meal and 7% of domestically produced soybean oil were exported. The United States produces far more soybean products than it can currently consume (primarily for animal feed and soybean oil). Production of biodiesel helps use the excess U.S. soybeans produced.

Table 4.26 U.S. Soybean Production and Deposition

Parameter	1996[a]	1997[b]	2000[b]	2005[b]
Amount planted (10^6 acres)	62.6	64.2	63.7	63.3
Amount harvested (10^6 acres)	61.6	63.4	62.7	62.3
Yield (bu/acre harvested)	35.3	37.6	39.4	42.2
Production (10^6 bu)	2,177	2,382	2,473	2,632
Domestic use (10^6 bu)[c]	1,481	1,514	1,582	1,709
Exports (10^6 bu)[c]	851	895	883	926
Soybean meal production (10^3 tons)	32,513	33,137	34,996	37,936
Domestic meal use (10^3 tons)	26,581	26,781	28,810	31,381
Meal exports (10^3 tons)	6,002	6,464	6,274	6,636
Soybean oil production (10^6 lb)	15,236	15,270	16,434	17,854
Domestic soybean oil use (10^6 lb)	13,460	13,661	14,537	15,306
Soybean oil exports (10^6 lb)	992	1,717	1,900	2,574

[a] The 1996 data are actual statistics as presented by the Food and Agricultural Policy Research Institute (1997).

[b] Data for 1997, 2000, and 2005 are values predicted by the Food and Agricultural Policy Research Institute (1997).

[c] The total of domestic use and exports of soybeans may be higher or lower than the total production in a given year because soybean stock changes each year.

Sheehan et al. (1998) presented data on use of fertilizer, energy, and pesticides (insecticide and herbicide) for soybean farming in 14 main soybean-producing states. We used their data to estimate fertilizer use, energy use, and pesticide use for soybean farming. Table 4.27 presents our estimates. Because these values are for 1990, we reduce them by 10% to the approximate values for 2005 used in GREET. The original data showed that virtually no insecticide was used for soybean farming.

In estimating energy use for transporting soybeans from soybean farms to soybean processing plants, we use the same assumptions regarding travel distance, type of trucks, and truck payload as those used for transporting corn to ethanol plants. The energy use difference (in Btu/bu) for transportation is caused by the weight difference per bushel between corn (56 lb/bu) and soybean (60 lb/bu). In this way, we estimate energy use of 5,247 Btu/bushel of soybean transported.

Regarding NO and N_2O emissions from nitrification and denitrification of nitrogen fertilizers, studies have confirmed that cornfields have higher NO and N_2O emissions than other crop fields. Thus, we assume an NO emission rate of 0.65% for fertilizer-N to NO-N, and 1.3% for fertilizer-N to N_2O-N. In comparison, cornfields have respective rates of 0.79% and 1.5%.

Table 4.27 Usage Intensity of Fertilizer, Energy, and Pesticide for Soybean Farming

Parameter	Value (1990)[a]	GREET Value (2005)
Fertilizer use (g/bu)		
Nitrogen (N)	132.1	119
Phosphate (P_2O_5)	414.2	373
Potash (K_2O)	705.0	635
Herbicide use (g/bu)	53.1	47.8
Insecticide use (g/bu)	0.534	0.48
Energy use share in Btu/bu (%)		
Gasoline	10,570 (29.6)	(29.6)
Diesel	23,605 (66.1)	(66.1)
LPG	928 (2.6)	(2.6)
Natural gas	2 (0)	(0)
Electricity	571 (1.6)	(1.6)
Total	35,710 (100)	32,140

[a] Values are based on data in Sheehan et al. (1998). The data are for soybean farming in 14 states in 1990. To calculate per-bushel usage intensities, the average yield (bu/acre) of soybean production in 1990 was used (34 bu/acre).

4.4.2 Soybean Oil Extraction

At soybean oil extraction plants, soybean seeds are crushed, the oil is extracted from the crushed seeds, and the crude soybean oil is refined. Soybeans contain 18–20% oil by weight. To maximize soybean oil production, organic solvents are used during the oil extraction from the crushed soybean seeds. The solvent extraction system is a widely used and well-established technology. The standard solvent extraction process uses n-hexane produced from petroleum. Most of the n-hexane used in oil extraction is recovered and recycled, with some inevitable loss. The inputs and outputs from oil extraction plants are presented in Table 4.28. As the table shows, the Sheehan et al. (1998) study estimates higher energy use and soybean feed input than the Ahmed et al. (1994) study. In addition to steam, Sheehan et al. includes the natural gas used for drying and processing products. As the table shows, input default values for GREET rely primarily on estimates by Sheehan et al.

In calculating emissions and energy use, we assume that steam is generated from natural gas. N-hexane is a straight-chain hydrocarbon. Commercial hexane is manufactured by distillation of straight-run gasolines that have been distilled from crude oil or natural gas liquids. In GREET, hexane is assumed to be produced from crude, and its upstream production energy use and emissions are adopted from energy use and emissions calculated for producing LPG from crude. Because hexane is volatile, the amount of hexane lost during soy oil extraction is assumed to be in the form of VOC emissions to the atmosphere.

Table 4.28 Inputs and Outputs of Soybean Oil Extraction Plants

Inputs and Outputs	Ahmed et al. 1994[a] Current Average	Ahmed et al. 1994[a] Industry Best	Sheehan et al. 1998	GREET Values[b]
Input				
Soybean (lb)	5.49	5.49	5.89	5.70
Steam (Btu)[c]	3,151	1,716	2,919	2,900 (44.5%)
NG (Btu)	0	0	2,826	2,800 (43.0%)
Electricity (kWh)	0.089	0.074	0.186	0.18 (9.4%)
N-hexane (Btu)	205	64	206	205 (3.1%)
Total energy (Btu)	3,660	2,032	6,586	6,519 (100%)
Output				
Soy oil (lb)	1	1	1	1
Soy meal (lb)	4.32	4.32	4.48	4.48

[a] The original values in Ahmed et al. were converted to the values shown by using a soy oil density of 7.7 lb/gal.

[b] We assumed in GREET that steam is produced from natural gas. Values in parentheses are percentage shares of process fuels.

[c] The amount of steam is presented as the amount of energy (in Btu) used to produce the needed steam.

As Table 4.28 shows, the process of soy oil extraction produces both soy oil and soy meals (an animal feed). Energy use and emissions from soybean farming and soy oil extraction need to be allocated between soy oil and soy feed. Three approaches are available for the allocation: weight-based, market value-based, and displacement. The weight-based approach could be used for soy oil production because the weights of both soy oil and soy meal can be measured. In contrast, the weight-based approach is not appropriate for ethanol production because the weight of the ethanol produced is not less meaningful than the Btu content. Table 4.29 presents the results of each allocation method. As discussed in Section 4.3.5, although the process energy approach can be used to allocate energy use and emissions of soy oil extraction plants, there are not enough available data to obtain an estimate by using that approach. The market value-based approach is used in GREET as the default approach.

4.4.3 Soy Oil Transesterification

The process of converting soy oil to methyl ester, the so-called transesterification process, is unique to the soybean-to-biodiesel cycle. The other upstream processes (i.e., soybean farming and soy oil extraction) are being used for soy oil production, regardless of whether the oil is used to produce biodiesel. The transesterification process involves reaction of the triglycerides present in soy oil with an alcohol such as methanol; the reaction is assisted by a catalyst (sodium hydroxide [NaOH] in this case). Table 4.30 presents inputs and outputs of biodiesel plants. To apply the values as specified in Table 4.30 to GREET, we assume that steam is generated with NG and that the energy embedded in the three chemical compounds is half oil and half NG.

Table 4.29 Split of Energy Use and Emissions between Soybean Oil and Soybean Meal

Allocation Approach	Split from Soybean Farming and Soy Oil Extraction (%) Soy Oil	Soy Meal
Weight	18.2	81.8
Market value[a]	33.6	66.4
Displacement[b]	62.1	37.9

[a] The market value approach uses a price of $220.36 per metric ton for soy meal and $498.56 per metric ton for soy oil. These prices are the average of the prices predicted by the Food and Agricultural Policy Research Institute (1997) for 1996–2006.

[b] These values are based on Ahmed et al. (1994), who assumed that soy meal would displace barley and estimated the amount of energy used for production of the displaced barley. Ahmed and his colleagues also estimated an energy credit of 81,229 Btu from soy meal for each gallon of soy oil produced.

Table 4.30 Inputs and Outputs of Biodiesel Plants with the Transesterification Process

	Ahmed et al. 1994			
Inputs and Outputs	Industry Average	Industry Potential	Sheehan et al. 1998	GREET Default Value
Inputs				
Soy oil (lb)	1.04	1.04	1.04	1.04
Steam (Btu)	2,470	507	1,864	1,865
Electricity (kWh)	0.25	0.20	0.013	0.10
Methanol (Btu)	992	1,172	773	800
Sodium hydroxide (Btu)	36.3	45.4	263	263
Sodium methoxide (Btu)	NE[a]	NE	10	10
Hydrochloric acid (Btu)			32	32
Total process energy (Btu)[b]	5,217	3,489	2,802	3,311
Outputs				
Biodiesel (lb)	1	1	1	1
Glycerine (lb)	0.109	0.109	0.213	0.213

[a] NE = not estimated.

[b] The total process energy includes the energy embedded in NaOH, sodium methoxide, and hydrochloric acid.

The transesterification process produces both biodiesel and glycerine, a specialty chemical. Upstream energy use and emissions need to be allocated between biodiesel and glycerine. Table 4.31 presents the split of energy use and emissions between the two on the basis of weight-, market value-, and displacement-based approaches. For the displacement approach, we assumed that glycerine can also be produced from petroleum. In GREET, the market value approach is used as the default approach. Note that the split between biodiesel and glycerine is used to allocate soy oil-related energy use and emissions of soybean farming and soy oil extraction as well as energy use and emissions for soy oil transesterification.

Table 4.31 Split of Energy Use and Emissions between Biodiesel and Glycerine

Allocation Approach	Split (%)	
	Biodiesel	Glycerine
Weight	82.4	17.6
Market value[a]	70.1	29.9
Displacement[b]	79.6	20.4

[a] The glycerine price has varied between $0.50 and more than $1 per lb in the past several years. Biodiesel is currently produced in very limited volumes, so its price can be as high as $4.50/gal. We assume that on a per-pound basis, the glycerine price is twice as high as the biodiesel price. We calculated market value split on the basis of this assumption.

[b] In the absence of glycerine production from soybeans, we assumed that glycerine can be alternatively produced from petroleum. Ahmed et al. (1994) estimated that the glycerine produced from the transesterification process was equivalent to 17,010 Btu/gal of biodiesel produced. Note that the glycerine production reported in Ahmed et al. is half of what GREET assumes. Thus, on the basis of GREET's glycerine production assumption, the energy credit can be about 34,020 Btu/gal of

4.5 Coal to Electricity

Over 50% of electricity used in the United States is generated from coal. In 1997, the United States produced 1,090 million tons of coal, and the three major coal-producing states — Wyoming, West Virginia, and Kentucky — produced 56% of the total U.S. coal (EIA 1998b). Of the 1,828 mines in operation in 1997, 874 were underground mines, and 954 were surface mines. Underground mines produced a total 421 million tons and surface mines produced 669 million tons. In 1997, the United States consumed 1,029 million tons of coal. Electric utilities consumed 88% of the total U.S. coal consumption (EIA 1998b).

Coal is classified into four types — bituminous, subbituminous, lignite, and anthracite — based on its carbon content, volatile mater content, and energy content. Bituminous coal, the most common type, is dense and black and with a moisture content of less than 20%. It is used for electricity generation, coke production, and space heating. Bituminous coal has a carbon content ranging from 69% to 86% by weight (dry matter). Its energy content ranges from 10,500 to 14,000 Btu/lb. Subbituminous coal is a dull black coal between lignite and bituminous coal with an energy content of 8,300–11,500 Btu/lb. Lignite coal is a brownish-black coal of low rank with high moisture and volatile matter. Its energy content is 6,300–8,300 Btu/lb. Anthracite coal is a hard, black lustrous coal containing a high percentage of carbon and a low percentage of volatile matter. Its carbon content ranges from 86% to 98%. In 1997, the United States produced 654 million tons of bituminous coal, 345 million tons of subbituminous coal, 86 million tons of lignite coal, and about 5 million tons of anthracite coal (EIA 1998b).

In 1997, the average quality of coal received by electric utilities was 10,275 Btu/lb energy content (HHV), 1.11% sulfur content, and 9.36% ash content. The average quality of coal received by coke and other manufacturing plants was 11,407 Btu/lb, 1.18% sulfur content, and 7.62% ash content (EIA 1998b). These specifications were used in the GREET model.

This section presents data for coal mining and coal transportation to power plants. Coal combustion in power plants and electricity transportation and distribution are discussed in Section 4.8.

4.5.1 Energy Efficiencies

On the basis of data presented in Delucchi (1991), Wang and Delucchi (1992), and Darrow (1994a), an energy efficiency of 99.3% is assumed in the GREET model for coal mining; an efficiency of 99.4% is assumed for coal transportation. Diesel fuel and electricity are used for coal mining. EIA (1998b) showed that, of the total tonnage of coal transported in 1997, 57% was moved by railroad cars; 22.3% by barges; 11.4% by trucks; and 9.3% by tramway, conveyor, and slurry pipeline. We assume that diesel fuel is used for railroad, truck, and pipeline transportation, and residual oil is used for barges. These values have been input into GREET.

4.5.2 Noncombustion Emissions

During the coal mining process, large amounts of the CH_4 contained in coal beds are released. Spath and Mann (1999) recently completed a life-cycle assessment of coal-fired power plants. They estimated 80.29 and 177.82 g of CH_4 emissions per million Btu of coal produced for surface mining and underground mining, respectively. EIA estimated that in 1997, 61% of the coal used in the United States was produced from surface mines and 39% from underground mines (EIA 1998b). Thus, we estimate an average CH_4 emission rate of 118.33 g/10^6 Btu of coal produced.

Coal is usually cleaned at mining sites to remove impurities such as sulfur, ash, and rock. By using data contained in Spath and Mann (1999), we estimate the following emission rates for coal cleaning: 7.016 g of VOCs, 4.07 g of PM_{10}, and 6.741 g of SO_x for each million Btu of coal produced.

4.6 Uranium to Electricity

Three stages of the uranium-to-electricity cycle (uranium mining, transportation, and enrichment) cause emissions because fuel combustion is involved in these stages. On the basis of data presented in Delucchi (1991), we assume an energy efficiency of 99.5% for uranium mining, 99.9% for uranium transportation, and 95.8% for uranium enrichment. No noncombustion emissions are assumed for this cycle. Natural gas, electricity, and residual oil are used for uranium mining. Diesel fuel is used in diesel locomotives and trucks for uranium transportation. Electricity is used for uranium enrichment.

4.7 Landfill Gases to Methanol

EPA (1991b) estimates that 3,000 to 6,000 landfills currently produce landfill gases primarily containing methane. The released methane is burned in flares at the landfill sites. Some companies have been developing compact, mobile facilities to produce methanol from landfill gases. Nationwide, there are about 600 landfills that generate large quantities of gases that can be used for methanol production; the GREET model includes this cycle of producing methanol from landfill gases.

4.7.1 Energy Efficiencies

During the process of converting landfill gas to methanol, energy is consumed to provide steam for the conversion process, to drive equipment, and to meet power needs in the plants. On the basis of data presented by SCAQMD for a proposed facility in southern California (SCAQMD 1994), we estimate an energy efficiency of 89.7% for the conversion process. The GREET model assumes that 99.3% of the consumed energy is electricity and the remaining 0.7% is landfill gases. Thus, 804 Btu of landfill gases and 33.4 kWh of electricity are consumed for each 10^6 Btu of methanol produced. Emissions from burning of the landfill gases are calculated from the amount of gases burned and the emission factors of natural gas combustion. Emissions from electricity consumption are estimated from the amount of electricity consumed and the average emission factors of electricity generation in a given region.

4.7.2 Emission Credits for Methanol Production

Because the production of methanol from landfill gases eliminates the practice of burning landfill gases in flares, the process of converting landfill gases to methanol earns emission credits equal to the amount of emissions that would otherwise be produced from combustion of landfill gases. On the basis of data presented in SCAQMD (1994), we calculate emissions credits of 5.582 g for VOCs, 106.1 g for CO, 21.6 g for NO_x, 35.36 g for PM_{10}, 7.393 g for SO_x, 706.8 g for CH_4, and 178,715 g for CO_2 for each 10^6 Btu of methanol produced. These emission credits, subtracted from emissions of the landfill-gas-to-methanol cycle, result in negative upstream emissions. On the other hand, as discussed later, emissions of on-vehicle methanol combustion are considered in calculating emissions from ICEVs fueled with the methanol that is produced from landfill gases.

4.8 Electricity Generation

Energy use and emissions of electricity generation are needed in GREET for two purposes: electricity usage of upstream fuel production activities and electricity use in EVs and grid-connected HEVs. Of the various power plants, those fueled by residual oil, NG, and coal produce emissions at plant sites. Nuclear power plants do not produce air emissions at plant sites, but emissions are associated with upstream uranium production and preparation stages, which are considered in GREET. The GREET model calculates emissions associated with electricity generation from residual oil, NG, coal, and uranium. Electricity generated from hydropower, solar energy, wind, and geothermal energy is treated as having zero emissions; these sources are categorized together in one group.

4.8.1 Combustion Technologies

For each fuel type, various combustion technologies can be used to generate electricity. In the GREET model, both current and future steam boilers are assumed for oil-fired plants. We also assume that current steam boilers will be phased out over time. For NG-fired power plants, the model assumes steam boilers, conventional gas turbines, and advanced combined-cycle gas turbines. For each fuel type, users can change the combustion technology mix in the GREET model to simulate emission impacts of a given combustion technology with a given fuel.

Spath and Mann (1999) recently completed a life-cycle assessment of coal-fired power plants. They assumed three coal-fired power plants: average plants operating around 1995 (energy conversion efficiency of 32%), plants meeting the new source performance standards (NSPS) (energy conversion efficiency of 34%), and plants equipped with low emission boiler systems (LEBS) (energy conversion efficiency of 42%). We treat the 1995 average plants as current plants, the NSPS plants as future plants, and the LEBS plants as advanced technology plants. Table 4.32 summarizes emission rates for the three plant types. These values have been input into GREET.

4.8.2 Power Plant Conversion Efficiencies

Table 4.33 presents power plant conversion efficiencies used in the GREET model and in some other studies. Oil-, NG-, and coal-fired boilers, NG-fired turbines, and nuclear plants are current technologies. Advanced NG combined-cycle turbines are a near-future technology, and advanced coal technologies (e.g., pressurized fluidized-bed combustion with combined cycle [PFB/CC] and integrated gasification with combined cycle [IGCC]) are a long-term future technology. Combined-cycle gas turbines are promoted because of their very high conversion efficiency and lower operating costs; some electric power plants have already incorporated this technology. The IGCC technology, first demonstrated in the mid-1980s, generates extremely low emissions, but its costs are high.

Table 4.32 Emissions Rates of Three Types of Coal-Fired Power Plants[a,b]

	Plant Type		
Emission Type	**Average Plant (Energy Conversion Efficiency of 32%)**	**NSPS Plant (Energy Conversion Efficiency of 34%)**	**LEBS Plant (Energy Conversion Efficiency of 42%)**
VOC	1.501	1.436	1.477
CO	12.567	12.617	12.309
NO_x	285.02	209.36	44.068
PM	12.661	12.617	6.524
SO_x	600.23	228.65	44.068
CH_4	0.75	0.943	5.098
N_2O	0.298	0.347	0.0328

[a] From Spath and Mann (1999).

[b] Emissions are in g/10^6 Btu coal input.

Table 4.33 Energy Conversion Efficiencies of Electric Power Plants (%)

Electric Power Plant Type	GREET	Delucchi 1991	Bentley et al. 1992		Wang and Delucchi 1992		Ecotraffic, AB 1992	Darrow 1994a	EIA 1995
Year			2010	2020	1990	2010			
Oil-fired boilers	34–35	31.8	34	34	31	35.4	38	33	36
NG-fired boilers	34–35	32.8	34	34	31.3	39	38	33	36
NG-fired turbines	34–35	33	34	36	31.4	31.4	38	33	29.8–37.3
NG-fired combined-cycle turbines	55	NE[a]	51	53	40	47	50	NE	46.3
Coal-fired boilers	34–35	32.9	38	40	33	37	38	33	35.4
Advanced coal technologies[b]	38	NE	NE	NE	37.9	44.8	NE	NE	38.7
Nuclear plants	34	NE	NE	34	NE	NE	NE	NE	NE

[a] NE = not estimated.

[b] Advanced coal combustion technologies include PFB/CC and IGCC.

Both currently used technologies and potential future technologies are included in GREET so that the model can simulate the impacts of using EVs and HEVs in the future with clean, efficient technologies to generate electricity.

4.8.3 Natural Gas-Fired Combined-Cycle Gas Turbines

In the electric utility sector, combined-cycle technology refers to the combined use of hot-combustion gas turbines and steam turbines to generate electricity. The arrangement of the two turbine types can increase the thermal efficiency of power plants far beyond the efficiency of conventional power plants using either type of turbine alone. Because of their economic and environmental superiority, NG-fired combined-cycle power plants are expected to take a significant market share of future power generation expansion (Zink 1998a; Hansen and Smock 1996).

A gas turbine consists of three major components: a compressor, a combustor, and a power turbine. Ambient air is drawn into the compressor and compressed up to 30 atmospheres (about 440 psi). The air is then directed to the combustor, where NG is introduced and burned. Hot combustion gases are diluted and cooled with additional air from the compressor and directed to the turbine. Energy from the hot, expanding exhaust gases is recovered in the form of shaft horsepower, which can be used to drive an external load generator for electricity generation. The primary environmental concerns for combined-cycle turbines are emissions of NO_x and CO. Turbine manufacturers have been working on new designs to reduce emissions as well as improve thermal efficiency. With continuously improved material coatings and cooling technologies, gas turbine inlet temperature has been increased to about 1,320^{o}C (2,400^{o}F), helping increase the efficiency of the combined cycle considerably (Zink 1998b; Viswanathan et al. 1999; Schimmoller 1998; Esch and DeBarro 1998; DeMoss 1996; Kuehn 1995a; Kuehn 1995b; Smith 1994). Also, by using a lean mixture of air and fuel, staging combustion at lower temperatures, and decreasing the residence time of gases in the combustor, turbine manufacturers have lowered NO_x emissions from advanced gas turbines to about 20 to 30 parts per million (ppm) without using water injection, selective catalytic reactors, or other post-combustion control devices (Kuehn 1995a; Kuehn 1995b; Smith 1994).

More efficient combined-cycle turbines may be designed by incorporating one of these options: simple lean combustion, two-stage lean/lean combustion, and two-stage rich/lean combustion (EPA 1996). Relative to a stoichiometric mixture of fuel and air, the lean mixture helps reduce the peak and average temperature within the combustor, resulting in lower rates of NO_x formation. The two-stage lean/lean combustion design involves two fuel-staged combustors; lean burning occurs in each. This design allows a turbine to operate with an extremely lean mixture and a stable flame that should not "blow-off" or extinguish. By contrast, the two-stage rich/lean design essentially involves air-staged combustors in which the primary zone is operated under fuel-rich conditions and the secondary zone under fuel-lean conditions. The rich mixture in the primary zone produces a lower temperature (compared to a stoichiometric mixture) and high concentrations of CO and H_2 (caused by incomplete combustion). The decreased temperature, the high concentration of CO and H_2, and the decreased amount of oxygen in the rich mixture help reduce NO_x formation. Before entering the secondary combustion zone, the combustion gas from the primary zone is quenched by a large amount of air, creating a lean mixture. The combustion of the lean mixture is then completed in the secondary zone with very low NO_x emissions.

The sensible heat of the hot exhaust gas from a gas turbine can either be discarded without heat recovery (the simple cycle) or used in a heat recovery steam generator (usually a Rankine-cycle generator) to generate additional electricity (the combined cycle). Because of its low capital investment, the simple cycle is often used for small, peak-load electricity generation. The combined cycle is used for large, base-load electricity generation. The thermal efficiency of a combined-cycle system with an inlet gas temperature of 2,400^{o}F is around 56%, based on the LHV of NG. The efficiency goal of the DOE Advanced Turbine Systems Program is 60% with an inlet gas temperature approaching 2,600^{o}F (Schimmoller 1998). We use an energy conversion efficiency of 55% for combined-cycle gas turbines.

4.8.4 Electric Generation Mixes

The electric generation mix greatly affects the fuel-cycle emissions of EVs and grid-connected HEVs. Because this mix differs significantly across regions, use of EVs and HEVs can have very different emission impacts in different regions. Table 4.34 presents the electric generation mix in various U.S. regions (Figure 4.4 shows these regions). The data show that on the West Coast and in the Northeast, where EV use is adopted or proposed, electricity is primarily generated from clean sources such as nuclear power, hydropower, and NG. Each of these electric generation mix sets can be input into the GREET model to simulate EV or HEV emission impacts.

Recharging of EVs and grid-connected HEVs will certainly not draw electricity from the average electric generation mix that is in place in the absence of EVs and HEVs. The so-called marginal electric generation mix for EVs and HEVs in a given region is determined by many factors: the excess electric generation capacity, the type of new additional power plants, the amount of total electricity needed by EVs and HEVs, the time of day that EVs and HEVs are recharged, and the way in which electric utilities determine their power plant dispatch.

There are large uncertainties involved in estimating marginal electric generation mixes. Several past major studies on EVs estimated the marginal electric generation mixes for recharging EVs (e.g., a multilaboratory study on EVs funded by DOE [Argonne National Laboratory et al. 1998a,b]). These past studies were usually region-specific and made specific assumptions about the number of EVs introduced. Preferably, marginal generation mixes should be used in estimating energy use and emissions associated with EVs and HEVs. GREET is designed to account for marginal generation mix in its calculations. Because of the uncertainties involved in estimating marginal mixes, we use average generation mixes to estimate EV and HEV energy use and emissions in this report. To show the impacts of electric generation mix, we estimate EV and HEV energy use and emissions for several regions that have distinctly different mixes. On the other hand, average generation mix is used for calculating energy use and emissions of the electricity to be used for upstream fuel production activities. This is why, in GREET, average and marginal generation mixes are two separate entries.

Table 4.34 Electric Generation Mixes of Various U.S. Regions in 2005 and 2015[a]

	Energy Source (%)				
Region	**Coal**	**Oil**	**NG**	**Nuclear**	**Others**
Year 2005					
East Central (ECAR)	83.7	0.2	5.8	8.5	1.8
Texas (ERCOT)	42.1	0.1	43.8	13.2	0.8
Mid-Atlantic (MAAC)	38.5	0.5	25.3	32.9	2.8
Illinois and Wisconsin (MAIN)	62.3	0.1	4.8	31.3	1.5
Mid-Continent (MAPP)	72.0	0.2	10.5	8.8	8.4
New York State (NY)	20.6	2.0	28.9	19.2	29.3
New England minus New York (NE)	13.0	7.5	48.1	19.0	12.4
Florida (FL)	50.6	5.9	24.3	16.8	2.5
Southeast minus Florida (STV)	59.8	0.2	8.4	26.0	5.5
Southwest (SPP)	61.7	0.1	22.1	13.2	3.0
Northwest (NWP)	27.7	0.1	17.3	2.8	52.0
Rocky Mountains and Arizona (RA)	58.5	0.1	18.1	12.9	10.4
California and Southeast Nevada (CNV)	23.1	0.4	30.4	18.7	27.3
California[b]	7.0	0.2	30.6	14.1	48.1
Northeastern U.S. average[c]	28.2	2.5	31.6	26.3	11.4
U.S. average	53.8	1.0	14.9	18.0	12.3
Year 2015					
East Central (ECAR)	76.1	0.2	16.1	6.1	1.6
Texas (ERCOT)	39.1	0.1	48.8	11.2	0.8
Mid-Atlantic (MAAC)	36.2	0.3	40.7	19.9	2.8
Illinois and Wisconsin (MAIN)	63.1	0.1	12.8	22.6	1.4
Mid-Continent (MAPP)	66.3	0.2	25.7	0.0	7.8
New York State (NY)	19.1	1.3	41.4	11.5	26.7
New England minus New York (NE)	11.4	4.7	55.7	16.1	12.1
Florida (FL)	54.9	4.4	29.5	8.9	2.4
Southeast minus Florida (STV)	56.4	0.2	21.8	16.7	4.9
Southwest (SPP)	53.9	0.1	33.7	9.7	2.7
Northwest (NWP)	25.7	0.1	22.8	2.6	48.8
Rocky Mountains and Arizona (RA)	50.5	0.1	29.4	10.9	9.1
California and Southeast Nevada (CNV)	44.8	0.3	23.4	8.7	22.8
California[b]	7.0	0.2	30.6	14.1	48.1
Northeastern U.S. average[c]	26.3	1.6	44.4	17.0	10.7
U.S. average	54.0	0.8	21.1	12.4	11.7

[a] Calculated from data presented in EIA (1997d), except as noted.

[b] From California Department of Finance (1996).

[c] The electric generation mix for the northeastern United States is the generated-electricity weighted average of Mid-Atlantic states (MAAC), New York State (NY), and the New England area without New York (NE).

4.9 Vehicle Operations

4.9.1 Alternative Fuels and Vehicle Technologies Included in GREET

The GREET 1 series is designed to estimate fuel-cycle energy use and emissions for passenger cars and LDTs only. The GREET 3 series is designed to estimate fuel-cycle energy use and emissions of heavy-duty trucks and buses. Table 4.35 presents near-term and long-term vehicle technologies. Near-term technologies are those already or almost available in the marketplace. Long-term technologies are those that require further research and development. Spark-ignition (SI) engines are assumed for vehicles fueled with RFG, CNG, LNG, M85, M95 (mixture of 95% methanol and 5% gasoline by volume), LPG, E85, and E95. Compression-ignition (CI) engines are assumed for vehicles fueled with CD, RFD, DME, FTD, and biodiesel. Baseline vehicles are assumed to be SI engines fueled with CG (for near-term options) and RFG (for long-term options).

In estimating fuel-cycle energy use and emissions for HEVs, the GREET model assumes a generic HEV type. Various on-board power units that use different fuels are proposed for use in HEVs; the model includes HEV types equipped with both SI and CI engines. HEVs can be grid-connected — energy is provided from grid electricity and from on-board power generation units — or they can be operated independently from grid electricity. Overall energy use and emissions for grid-connected HEVs are calculated by using the average energy use and emissions of the grid electricity mode and on-board engines weighted by VMT in each mode. The all-electric range of an HEV depends on its battery size, its battery state-of-charge operating range, and its driving patterns. Thus, the all-electric range, which is specific to an HEV model, an HEV operation control strategy, and a driving cycle, can be determined only by using dynamic models that simulate HEV operations (Wang et al. 1997a). Recent simulations of HEVs at Argonne indicate that grid-connected HEVs could make 30% of their total VMT by using grid electricity (Vyas 1998). GREET 1.5 uses this value to calculate average energy use and emissions of grid-connected HEVs.

The GREET model assumes proton-exchange membrane fuel-cells for hydrogen-, gasoline-, methanol-, NG-, and ethanol-fueled FCVs. FCVs fueled with all fuels except hydrogen are assumed to be equipped with on-board fuel processors (steam reforming and partial oxidation technologies) to produce hydrogen from these fuels.

In running GREET, energy use and emissions of individual AFVs are calculated for near-term and long-term technology options. The near-term technologies are those available now; the near-term baseline GVs are subject to federal Tier 1 emission standards.

The long-term technology options are those that are currently in the research and development stages and may be available in about 10 years. The long-term baseline GVs are assumed to meet the federal Tier 2 emission standards proposed recently by EPA (1999). The fuel economy of baseline gasoline cars will be improved on the near-term baseline vehicles.

Table 4.35 Near- and Long-Term Vehicle Technology Options for Passenger Cars, Light-Duty Trucks 1, and Light-Duty Trucks 2[a]

Near-Term Options (MY 2000)	Long-Term Options (MY 2010)
GVs: RFG2	CNGVs: dedicated
CNGVs: bi-fuel	LNGVs: dedicated
CNGVs: dedicated	LPGVs: dedicated
LPGVs: dedicated	M90-dedicated vehicles
FFVs: M85	E90-dedicated vehicles
FFVs: E85	SIDI vehicles: RFG2
EVs	SIDI vehicles: M90
Grid-independent SIDI HEVs: RFG2	SIDI vehicles: E90
Grid-connected SIDI HEVs: RFG2	Grid-independent SIDI HEVs: RFG2
CIDI vehicles: CD	Grid-independent SI HEVs: CNG
Grid-independent CIDI HEVs: CD	Grid-independent SI HEVs: LNG
	Grid-independent SI HEVs: LPG
	Grid-independent SIDI HEVs: M90
	Grid-independent SIDI HEVs: E90
	Grid-connected SIDI HEVs: RFG2
	Grid-connected SI HEVs: CNG
	Grid-connected SI HEVs: LNG
	Grid-connected SI HEVs: LPG
	Grid-connected SIDI HEVs: M90
	Grid-connected SIDI HEVs: E90
	CIDI vehicles: RFD
	CIDI vehicles: DME
	CIDI vehicles: FT50
	CIDI vehicles: BD20
	Grid-independent CIDI HEVs: RFD
	Grid-independent CIDI HEVs: DME
	Grid-independent CIDI HEVs: FT50
	Grid-independent CIDI HEVs: BD20
	Grid-connected CIDI HEVs: RFD
	Grid-connected CIDI HEVs: DME
	Grid-connected CIDI HEVs: FT50
	Grid-connected CIDI HEVs: BD20
	Evs
	FCVs: H_2
	FCVs: methanol
	FCVs: gasoline
	FCVs: ethanol
	FCVs: CNG

[a] GV = gasoline vehicle; RFG2 = reformulated gasoline 2; CNGV = compressed natural gas vehicle; LNGV = liquified natural gas vehicle; LPGV = liquefied petroleum gas vehicle; M90 = mixture of 90% methanol and 10% gasoline by volume; FFV = flexible-fuel vehicle; M85 = mixture of 85% methanol and 15% gasoline by volume; E90 = mixture of 90% ethanol and 10% gasoline by volume; E85 = mixture of 85% ethanol and 15% gasoline by volume; SIDI = spark-ignition, direct-injection; HEV = hybrid electric vehicle; CD = conventional diesel; CIDI = compression-ignition, direct-injection; CNG = compressed natural gas; LNG = liquified natural gas; LPG = liquified petroleum gas; RFD = reformulated diesel; DME = dimethyl ether; FT50 = mix of 50% Fischer-Tropsch and 50% conventional diesel (by volume); BD20 = mix of 20% biodiesel and 80% conventional diesel (by volume); FCV = fuel cell vehicle; H_2 = hydrogen.

Fuel economy for AFVs is calculated from baseline GV fuel economy and relative improvement in fuel economy between GVs and the other vehicle types. The results of these calculations are presented in the following sections.

Emissions from vehicle operations are calculated for nine pollutants or sources: exhaust and evaporative VOCs, CO, and NO_x; exhaust PM_{10}; and PM_{10} from brake and tire wear; and exhaust SO_x, CH_4, N_2O, and CO_2. VOC emissions (both exhaust and evaporative), CO, and NO_x for GVs and CD vehicles are calculated by using EPA's Mobile model. The current version of Mobile (Mobile 5b) does not include any AFVs. EPA plans to release the next version of Mobile (Mobile 6) by the end of 1999. At present, EPA plans to include only CNGVs in Mobile 6. Emissions of PM_{10} (both exhaust and brake wear/tire wear) for GVs and CD vehicles are calculated by using EPA's Part 5 model.

In analyzing vehicle emission performance, researchers must consider that there are three types of emission rates (in g/mi). The first is emission standards to which motor vehicles are subject. These are the maximum allowable emission rates that vehicles can emit for a specified accumulated mileage. In the United States, vehicle emission standards are established by CARB for California and by EPA for the rest of the country.

The second type is emission certification rates. These are laboratory-tested emissions for new vehicles. Vehicles are tested by manufacturers under controlled laboratory conditions by following testing protocols. The certification rates are compared with applicable emission standards to determine whether a given vehicle model meets emission standards.

The third type is estimated on-road emissions of given vehicle groups. Motor vehicles experience various emission deterioration effects from laboratory-controlled conditions to actual on-road operating conditions. Estimated on-road emission rates, often based on laboratory testing results under different on-road operating conditions, account for the deterioration effects. The estimated on-road emission rates are usually used by states and local governments to estimate the mobile source emission inventory. The Mobile and Part models were developed to estimate on-road emission rates of motor vehicles. Usually, certification emission rates are lower than emission standards, and emission standards are lower than on-road emissions because on-road operating conditions are generally less ideal than laboratory testing conditions.

Ideally, Mobile and Part should include conventional and advanced vehicle technologies. In that case, the models could be used to estimate on-road emission rates for each vehicle type. However, the models include only vehicles fueled by conventional gasoline and diesel fuel. For GREET simulations, Mobile and Part are used to develop on-road emission rates for baseline gasoline and diesel vehicles. Then, emission changes between baseline vehicles and alternative-fueled/advanced vehicles are estimated on the basis of laboratory-tested emissions of baseline vehicles and new vehicle types. GREET model is intended to estimate on-road emissions. And although Mobile and Part have problems in estimating on-road emissions, until better models are developed, they are still the most widely used models for estimating on-road emissions.

4.9.2 Gasoline Vehicles Fueled with Reformulated Gasoline

The 1990 CAAA required the use of RFG in some of the nation's worst ozone nonattainment areas. The requirement was designed in two tiers. The so-called federal Phase 1 RFG (FRFG1) took into effect in January 1995, and the Phase 2 RFG (FRFG2) will take effect in 2000. The CAAA requires a minimum VOC reduction of 15% by FRFG1 and a minimum reduction of 25% by FRFG2. FRFG1 could be certified with composition requirements or emission performance standards. FRFG1 composition requirements are less than 1% (by volume) benzene, less than 25% (by volume) aromatics, and more than 2% (by volume) oxygen. Under the performance standard requirements, FRFG1 is required to reduce per-gallon VOC emissions by 16% (northern regions) to 35% (southern regions) and air toxics emissions by about 15%, relative to CG (EPA 1994). Note that the reduction for VOC emissions is the combined reduction of exhaust and evaporative emissions, with evaporative emissions reductions accounting for the greater share. FRFG2 will be certified by using emission performance standards under which FRFG2 is required to reduce VOC emissions by 27.5% in southern regions and 25.9% in northern regions, air toxic emissions by 20%, and NO_x emissions by 5.5%, all relative to CG.

California established its own RFG requirements. The California RFG requirements were designed in two tiers, too. The California Phase 1 RFG (CARFG1) standards took effect in January 1992. CARFG1 has the following composition requirements: maximum aromatic content of 32% (by volume), maximum sulfur content of 150 ppm (by weight), maximum olefin content of 10% (by volume), and maximum 90% distillation temperature of 330°F (CARB 1991). The California Phase 2 RFG (CARFG2) took effect in January 1996. Table 4.36 presents its specifications (CARB 1998). Gasoline producers are allowed to certify RFG by using the specification requirements or by the emission performance requirements under which producers need to demonstrate a different set of specifications can meet predetermined emissions reduction requirements.

Table 4.36 Specifications of California Phase 2 Reformulated Gasoline[a]

Parameter	"Flat" Limit	"Average" Limit	"Cap" Limit
RVP (psi)	7.0	none	7.0
Sulfur (weight ppm)	40	30	80
Benzene (volume %)	1.0	0.80	1.20
Aromatics (volume %)	25	22	30
Olefins (volume %)	6.0	4.0	10
Oxygen (weight %)	1.8–2.2	none	3.5 (max)
T50 (°F)	210	200	220
T90 (°F)	300	290	330

[a] From CARB (1998).

Recently, EPA proposed Tier 2 emission standards for passenger cars and LDTs up to 8,500 lb gross vehicle rated weight. The proposed Tier 2 standards call for new motor vehicles (manufactured after 2004) to meet a 0.07-g/mi NO_x standard and 0.01-g/mi PM standard. To allow new vehicles to meet these standards, EPA proposes a reformulated gasoline (RFG2) with an average sulfur content of 30 ppm and a sulfur content cap of 80 ppm to be produced by 2006. The newly proposed RFG is similar to California RFG2. In our analysis, we assume that the federal RFG2 after 2005 will be the same as California RFG2.

Because the newly proposed federal RFG2 is similar to California RFG2. We estimate energy and emissions changes for only the federal RFG2. Table 4.37 shows changes in fuel economy and emissions achieved by using RFG, relative to CG. The study by Battelle (Battelle Memorial Institute 1995a,b; Orban et al. 1995) was conducted for the South Coast Alternative Fuels Demonstration Project, also known as the CleanFleet Project. The purpose of the project was to gather data on the AFV types available in the early 1990s. Through the project, Federal Express delivery vans were recruited for laboratory emissions tests as they accumulated mileage. A total of 111 vans (weighing between 4,800 and 5,700 lb) from service fleets in Los Angeles were tested or monitored. These vans were fueled with CG, CARFG2, LPG, CNG, M85, and electricity. Laboratory emissions tests were performed by CARB on 36 vans: 12 Chevrolet vans (three aftermarket-converted LPG vans, three aftermarket-converted CNG vans, three gasoline vans fueled with CARFG2, and three gasoline vans fueled with CG), nine Dodge vans (three CNG vans produced by original equipment manufacturers [OEMs], three gasoline vans fueled with CARFG2, and three gasoline vans fueled with CG), and 15 Ford vans (three OEM-produced methanol flexible-fuel vans, three aftermarket converted LPG vans, three OEM-produced CNG vans, three gasoline vans fueled with CARFG2, and three vans fueled with CG). Emissions were measured for THC, NMHC, NMOG, CO, NO_X, CH_4, N_2O, and air toxics.

The Auto/Oil Air Quality Improvement Research Program (AQIRP) was established in 1989 with the participation of 14 oil companies and the big three domestic automakers. The program was intended to provide data on emissions and air quality effects associated with the fuel quality of gasoline and alternative fuels. Between 1989 and 1993, the AQIRP researchers conducted more than 5,000 emissions tests in which they used more than 90 fuel compositions in more than 100 vehicles (AQIRP 1997). Emission tests were conducted with CARFG2 on three vehicle categories: an “older” vehicle fleet (1983–1985 MY vehicles), current vehicle fleet (1989 MY vehicles [current when the AQIRP program started]), and federal Tier 1 fleet (1994 MY vehicles). Another vehicle group — the advanced technology fleet — was not tested with average gasoline, so emission changes between RFG and CG could not be estimated for this group. The study showed that CARFG2 used in federal Tier 1 vehicles generally achieved greater emissions reductions than when it was used in other vehicles. This finding implies that newer vehicles can be designed to tap the emissions reduction potential of RFG to a greater extent than older vehicles.

Table 4.37 Changes in Fuel Economy and Emissions by Use of Reformulated Gasoline: Test Results[a]

		Change Relative to CG (%)				
Source	**Vehicle Model**	**Economy (mpg[b])**	**Exhaust VOCs**	**CO**	**NO_x**	**CH_4**
Battelle[c]	1992 Chevy 4.3-L van	0.7[d]	-34.4[e]	-25.0	-15.2	2.5
	1992 Dodge 5.2-L van	-3.0	-34.1	-18.9	-27.1	-16.7
	1992 Ford 4.9-L van	-2.2	-14.3	-1.9	4.9	-3.3
AQIRP [f]	Older vehicles[g]	-2	-12	-23	-9	NA[h]
	Current vehicles[i]	-3	-22	-21	-7	NA
	Tier 1 vehicles[j]	-4	-27	-28	-16	NA
	Three MeOH FFVs[k]	-1.0	-31.3	-18.3	-25.5	NA
	Three large LDVs[l]	0.0	-20.5	-29.9	-21.5	-13.6
	Three EtOH FFVs[m]	-7.5	-11.8	8.3	-7.0	NA
GRI[n]	Two 1996 Ford large cars[o]	-3.1	-2.7	10.8	6.3	16.7
	Two 1995 Dodge Caravans	-2.3	-9.9	-8.0	-16.3	12.9
	Two 1995 Dodge Ram Vans	-3.0	-16.2	-8.6	-7.7	0

[a] Values are measured in percent relative to use of CG, under the federal test procedure (FTP) cycle.

[b] mpgeg = miles per gasoline-equivalent gallon.

[c] From Battelle Memorial Institute (1995a,b) and Orban et al. (1995). Emissions were tested in three phases as vehicle mileage accumulated. The values here are the average of the results from the three phases. The RFG was CARFG2.

[d] In the Battelle study, mpg was determined in two ways: first, on the basis of actual fuel consumption and mileage for each fuel, and second, on the basis of laboratory tests under the FTP cycle. The on-road results were affected by driving patterns, traffic conditions, and many other factors. With RFG and CG, mpg could be tested under exactly the same driving conditions. Laboratory-tested mpg results were used here to determine mpg changes by RFG.

[e] For NMOG.

[f] From AQIRP (1995a; 1996). The tested RFG was CARFG2.

[g] The older vehicles tested were seven 1983–1985 MY vehicles.

[h] NA = not available.

[i] The current vehicles tested were ten 1989 MY vehicles.

[j] The Tier 1 vehicles tested were six 1994 MY vehicles.

[k] From AQIRP (1995c). The three methanol FFVs were a 1993 Dodge 2.5-liter (L) Spirit, 1993 Ford 3.0-L Taurus, and 1992 Chevrolet 3.1-L Lumina.

[l] From AQIRP (1995b). The three large LDVs were a 1992 Chevrolet 5.7-L C20 pickup, 1993 Ford 4.6-L Crown Victoria, and 1992 Dodge 5.2-L B150 Ram Wagon. The three vehicles were the baseline GVs tested together with CNG vehicles for emission comparisons.

[m] From AQIRP (1995c). The three ethanol FFVs were a 1993 Chevrolet 3.1-L Lumina, 1993 Ford 3.0-L Taurus prototype, and 1993 Plymouth 2.5-L Acclaim prototype.

[n] From Engine, Fuel, and Emissions Engineering, Inc. (1997). The tested RFG was FRFG2.

[o] The two cars were a Ford Crown Victoria and a Ford Grand Marquis.

In summary, the AQIRP concluded that with Tier 1 vehicles, CARFG2 achieved 18–36% reductions in HC emissions, 19–38% in CO emissions, 6–27% in NO_x emissions, and 23–41% in air toxics emissions (AQIRP 1997; *Automotive Engineering* 1996a,b). CARFG2 reduced volumetric fuel economy by 2–4%. Note that the baseline CG used in the AQIRP was a blend to represent 1988 national average gasoline composition.

The study for GRI was conducted with newer vehicles fueled with FRFG2. Because of the use of FRFG2, the study showed consistently lower emission benefits than the other two studies.

On the basis of the results presented in the Table 4.37, we assume emission and fuel economy changes of CARFG2 and FRFG2 relative to CG (Table 4.38). Note that in our application of GREET in this study, we assume an RFG similar to California RFG2 because of EPA's newly proposed federal RFG (EPA 1999).

Table 4.38 Reductions in Emissions and Fuel Economy by Use of Reformulated Gasoline: Regulatory Specifications

	Reduction (%)	
Parameter	**CARFG2**	**FRFG2**[a]
Exhaust VOCs	27[b]	26[c]
Evaporative VOCs	27[d]	26[c]
CO	28[b]	20[d]
NO_x	15[b]	5[c]
PM_{10}	5[d]	5[d]
CH_4	8[b]	8[d]
N_2O	0[d]	0[d]
Volume mpg	2[b]	2[d]
Btu mpg	0[d]	0[d]

[a] The federal RFG2 before the newly proposed federal RFG2 with 38 ppm sulfur content.

[b] Based on testing results from Battelle (1995a,b) and AQIRP (1995a,b,c; 1996).

[c] Based on EPA's emissions performance standards for federal RFG2.

[d] Assumed in this study.

4.9.3 Compressed Natural Gas Vehicles

For model year 1999, the following CNGV models are offered for purchase: Chrysler Ram wagon, Chrysler Ram van, Ford Contour (bi-fuel), Ford Crown Victoria, Ford Econoline Super Club, Ford Econoline E-350 van, Ford F-Series pickup truck, Chevrolet Cavalier, and GMC Sierra 2500 truck (*New Fuels and Vehicles Report 1998*). Table 4.39 summarizes changes in fuel economy and emissions by CNGVs relative to GVs. In studies conducted by NREL for DOE on AFV emissions (Kelly et al. 1996a,b,c), NREL tested CNGVs and methanol and ethanol FFVs. For methanol FFVs, NREL tested 71 1993-MY methanol Dodge Spirit FFVs and 16 1993-MY methanol Econoline FFVs. The FFV Spirit was an EPA-certified production vehicle, while the FFV Econoline was an uncertified prototype demonstration vehicle. A similar number of gasoline Spirits and E150 Econolines were tested. The FFVs were fueled with M85, M50, and CARFG2 (as the baseline fuel). For ethanol FFVs, NREL tested 21 1992/93-MY ethanol variable-fuel vehicle (VFV) Luminas and a similar number of gasoline Luminas. The ethanol VFVs were tested with E85, E50, and CARFG2. For CNG vehicles, NREL tested 37 dedicated CNG Dodge B250 vans and 38 gasoline B250 vans, all of which were 1992–94 MY vehicles. The CNG van, equipped with a catalytic converter specifically designed for reducing emissions from CNGVs, was certified to meet CARB's low-emissions vehicle (LEV) emissions standards. Because CARFG2 was used as the baseline fuel, emission changes of CNG, methanol, and ethanol were calculated relative to CARFG2, not CG.

Table 4.39 Changes in Fuel Economy and Emissions by Use of Compressed Natural Gas Vehicles[a]

		Change Relative to CG (%)					
Source	**Vehicle Model**	**Fuel Economy**	**Exhaust VOCs**	**CO**	**NO$_x$**	**CH$_4$**	**N$_2$O**
Battelle[b]	Chevy 5.7-L van[c]	-15.7	-81.7	-72.3	-57.6	3,626.1	-82.8
	Dodge 5.2-L van	-9.7	-93.8	-78.8	-45.1	808.3	-56.4
	Ford 4.9-L van	-2.2	-61.1	-69.0	105.4	2,167.2	35.2
AQIRP[d]	1992 GM 5.7-L Sierra Pickup[e]	-17.0	-86.5	-21.0	-74.6	1,311.5	NA[f]
	1993 Ford 4.6-L Crown Victoria [e]	-14.4	-80.0	-59.3	-47.7	1,223.3	NA
	1992 Chrysler 5.2-L B150 van[e]	-22.8	-89.1	-72.7	-8.6	900.0	NA
NREL[g]	92 and 94 MY 5.2-L Dodge B250 van	-7.9	-80.4	-45.4	-31.1	NA	NA
						NA	NA
SWRI[h]	1994 MY 4.3-L GMC 1500 pickup (aftermarket conversion)	5.5	-87.9	-18.3	-37.2	1,168.3	NA
GRI[i]	1996 MY Ford Crown Victoria dedicated	-4.7	-66.2	-4.6	-63.3	975.0	NA
	1995 MY Dodge Caravan dedicated	-14.1	-88.4	-83.2	-63.9	187.1	NA
	1994 Dodge Ram van dedicated	2.3	-93.1	-12.4	36.3	478.7	NA
	1996 Dodge Ram van dedicated	-6.1	-83.1	-87.0	-32.9	278.7	NA
Ford[j]	1997 Ford 5.4-L F-250 pickup dedicated	-16.0	-91.0	-39.0	-50.0	NA	NA
	1997 Ford 5.4-L E-250 van dedicated	-18.0	-95.0	-65.0	-65.0	NA	NA
Honda[k]	1998 Honda Civic GX	-6.1	-96.4	-90.9	-85.4	NA	NA
EPA certification[l]	1995 Dodge Caravan dedicated	NA	-80.0	-85.8	-39.2	NA	NA
	1995 Dodge Caravan dedicated	NA	-85.7	-82.1	-37.5	NA	NA
	1996 Ford Crown Victoria dedicated	NA	-57.1	32.8	-88.2	NA	NA
	1996 Ford 2.0-L Ford Contour[l,m]: bi-fuel	NA	15.7	4.8	100.0	NA	NA
	1997 Ford Crown Victoria dedicated	NA	-51.7	-50.0	-86.7	NA	NA
	1997 Chrysler minivan dedicated	NA	-85.8	-72.9	-52.6	NA	NA
	1998 Ford Crown Victoria dedicated	NA	-86.5	-35.1	34.8	NA	NA
	1998 Chevy C2500 pickup bi-fuel (OEM)	-4.6	-77.3	-23.0	-12.1	1,472.0	NA
	1998 Chevy C2500 pickup bi-fuel (OEM)	-5.9	-77.1	-29.4	-4.2	1,437.0	NA
	1998 Chevy Cavalier bi-fuel (OEM)	NA	-52.2	-15.8	0	NA	NA
	1998 Chevy Cavalier bi-fuel (OEM)	NA	-77.1	-29.4	-4.2	NA	NA
	1998 Ford 2.0-L Contour: bi-fuel[k]	NA	-66.7	-23.7	-8.2	NA	NA
	1998 Ford 2.0-L Contour: bi-fuel[k]	NA	-42.0	-16.7	0.0	NA	NA
Santini and Saricks[n]	Passenger cars	NA	-76.0	-33.0	0.0	NA	NA
	Pickup trucks	NA	-81.0	3.0	-6.0	NA	NA
	Standard vans	NA	-95.0	-76.0	-63.0	NA	NA
NREL[o]	1996 Ford Crown Victoria	-11.6	-67.9	-62.8	-2.1	1,760	NA
NGVC[p]	1996 Ford Crown Victoria	NA	-20.0	-69.8	-58.5	23,00	NA

Continued

Table 4.39 (Cont.)

[a] Values are in % relative to vehicles fueled by CG, under the FTP cycle.

[b] From Battelle Memorial Institute (1995a,b) and Orban et al. (1995). Emissions were tested in three phases during which mileage accumulated. The values here are the average of the results from the three phases.

[c] The CNG vans were converted from gasoline vans by IMPCO Technologies, Inc.

[d] From AQIRP (1995b).

[e] The three CNG vehicles were a 1992 MY Chevrolet 5.7-L C20 pickup, 1992 MY Dodge 5.2-L Ram van, and 1993 MY Ford 4.6-L Crown Victoria.

[f] NA = not available.

[g] From Kelly et al. (1996a). The results were based on tests conducted in two emission testing laboratories. The emission and fuel economy changes are relative to GVs fueled with CARFG2. The study showed an evaporative HC emissions reduction of 50.8% by the CNG van.

[h] From Southwest Research Institute (1995). The bi-fuel CNG pickup was converted from a gasoline pickup with a bi-fuel conversion kit provided by Mesa Environmental.

[i] From Engine, Fuel, and Emissions Engineering, Inc. (1997).

[j] From Vermiglio et al. (1997).

[k] Fuel economy change is from Suga et al. (1997). Emission changes are from EPA certification data for CNG Civic GX and gasoline Civic LX. The CNG Honda Civic GX was designed to have emissions that are one-tenth of ULEV standards.

[l] From certification data obtained by Argonne National Laboratory from EPA.

[m] Bi-fuel CNG vehicle converted by GFI Control Systems, Inc.

[n] From Santini and Saricks (1999). Their emission changes were based on emission certification rates and FTP emission rates estimated with Mobile for CNGVs and their gasoline counterparts.

[o] From Whalen et al. (1999). Results are from vehicles selected from Barwood Cab fleet in Maryland. Results here are an average of the results at 60,000, 90,000, and 120,000 mi. Emission changes are relative to emissions of CARFG2. The fuel economy result is laboratory-tested fuel economy.

[p] From Chan and Weaver (1998). The study was conducted for the Natural Gas Vehicle Coalition. Vehicles were taken from the Barwood Cab fleet in Maryland. Emission tests were conducted with the I/M 240 cycle.

A Southwest Research Institute (1995) study conducted for GRI involved performing emissions testing of a 1994 MY bi-fuel, aftermarket converted GMC 1500 CNG pickup. Fuels tested on the pickup included CNG, CG, and FRFG1. Emissions were measured under the normal federal test procedure (FTP) temperature (75°F), the cold FTP (20°F), and the hot, stabilized REP05 (representative cycle No. 5) cycles. Emissions tests were conducted under the cold FTP and the REP05 cycles because under cold temperature and aggressive driving conditions, GVs are expected to switch to fuel enrichment operations, while CNGVs are not required to do so, resulting in larger emissions reduction potentials for CNGVs under these two cycles. Emissions were measured for NMOG, CO, NO_x, CH_4, CO_2, and air toxics.

The EPA has certified some AFV models for meeting applicable emission standards, and Argonne has obtained these certification data from the EPA. Emissions for vehicle certification were usually measured for vehicles with an accumulated mileage of around 4,000 miles. Emissions deterioration factors — multipliers to the measured emissions — were then used to estimate emission certification levels at 50,000 miles and/or 100,000 miles. Emissions deterioration factors were usually greater than one. However, in some cases, the EPA showed deterioration factors that were less than one. In these cases, the EPA applied a factor of one to measured emissions; meaning that in these cases, emissions were not subject to deterioration at all, which is questionable.

In theory, CNGVs can be designed more energy efficient because NG has a higher octane number than gasoline, so NG engines can be designed with a higher compression ratio. However, on-board CNG cylinders cause an additional weight penalty; cylinders can weigh 200–500 lb. In addition, CNGVs have lower volumetric energy efficiency than gasoline. On the basis of testing results, it seems that manufacturers have not designed CNGVs to realize their potential engine efficiency advantage, which results in a substantial fuel economy penalty for CNGVs. Thus, for near-term CNGVs, we assume a fuel economy penalty of 5–7%. For long-term CNGVs, we assume that the potential engine efficiency gain will offset the extra weight penalty, and CNGVs will achieve the same or better fuel economy than those of comparable GVs.

Because of the nature of CNG, CNGVs should not have fuel-related evaporative emissions; we assume zero evaporative emissions from CNGVs. Some actual tests have shown that CNGVs undergoing evaporative emissions tests did generate evaporative emissions (Kelly et al. 1996a). Researchers speculated that the evaporative emissions were from tires, seats, and other plastic and rubber parts, which we do not include in this analysis. CNGV evaporative emissions could be from fuel leakage from CNG cylinders and fuel lines. In this case, the so-called evaporative emissions are mainly methane.

No emission tests are available for LDTs fueled by LNG. Southwest Environmental Consultants converted a 1994 GM 7.4-liter (L) HDT fueled by CG into an LNG truck (Smith 1997). Emissions testing on that LNG truck demonstrated emissions reductions of 97% for NMOG, 25% for CO, and 25% for NO_x. Because of the limited data for LNG vehicles, we use emissions and fuel economy changes of CNGVs for LNGVs.

On the basis of these test results, we assume fuel economy and emission changes for CNGVs in the near term and in the long term (Table 4.39).

4.9.4 Methanol Vehicles

In the early 1990s, automakers offered methanol FFVs, but they have recently stopped offering these vehicles. Table 4.40 summarizes emissions testing results for methanol FFVs. Fuel economy and emissions changes by M85 in the NREL study are relative to CARFG2, not CG. Note that EPA certification data for the Ford Taurus FFV show emissions increases by M85. The certification emissions for both the M85 FFV and the gasoline Taurus at 50,000 mi were calculated from emissions tested at 4,000 mi and emission deterioration factors developed for GVs only. It is not clear whether M85 will have the same deterioration rates (say, in g/10,000 mi) as gasoline. Thus, the certification data may not reveal true emission changes by M85.

Table 4.40 Changes in Fuel Economy and Emissions by Use of M85 Flexible-Fuel Vehicles[a]

		Change Relative to CG (%)						
Source	**Vehicle Model**	**Economy (mpgeg)**	**Exhaust VOCs**	**Evap. VOCs**	**CO**	**NO_x**	**CH_4**	**N_2O**
AQIRP[b]	Three 1993 FFVs[c]	4.1	-37.3	-2.1	-12.7	-10.6	NA[d]	NA
Battelle[e]	Ford 4.9-L van	-1.4	-46.3		-54.0	-9.9	-56.1	170.5
NREL[f]	1993 Dodge 2.5-L Spirit	-0.1	-16.9	-6.8	2.0	27.2	NA	NA
	1993 Ford 4.9-L Econoline E150	-3.0	-12.4	-28.1	-32.3	13.5	NA	NA
EPA	1997 Ford 3.0-L Taurus FFV		58.6		6.5	15.4	NA	NA
Certification	1996 Ford 3.0-L Taurus FFV		20.0		-20.0	0	NA	NA

[a] Values in % relative to GVs using CG, under the FTP cycle.

[b] From AQIRP (1994).

[c] The three FFVs were a Chrysler 2.5-L Acclaim, Ford 3.0-L Taurus, and GM 3.1-L Lumina.

[d] NA = not available.

[e] From Battelle Memorial Institute (1995a,b) and Orban et al. (1995). Emissions were tested in three phases as vehicle mileage accumulated. The values here are the average of the results from the three phases.

[f] From Kelly et al. (1996c). Changes in emissions and fuel economy by M85 are relative to CARFG2.

In the near term, FFVs seem to be the plausible vehicle option for using methanol, when the limited methanol refueling infrastructure and cold start problems with M100 are considered. In the long term, as the methanol refueling infrastructure becomes relatively extensive and the cold start problem is solved, dedicated methanol vehicles using high methanol blends — such as M90 — may be a practical option. At present, no fuel economy and emissions testing data are available for dedicated methanol vehicles. We assume greater fuel economy and emissions benefits for M95 dedicated vehicles than for M85 FFVs.

4.9.5 Ethanol Vehicles

At present, Ford is selling an FFV Taurus (3.0-L engine), and Chrysler is selling its FFV minivan (3.3-L engine). Ford will produce an FFV Ranger pickup (3.0-L engine) and an FFV Windstar minivan (3.0-L engine) in MY 2000. Table 4.41 shows fuel economy and emission changes of E85 FFVs relative to CG. Again, changes from the NREL study are relative to CARFG2, not CG. Note that EPA certification data show moderate emissions benefits and large fuel economy benefits for the 1998 MY Ford Taurus FFV.

We expect that in the near term, FFVs using E85 will continue to be introduced. We assume fuel economy and emission changes of near-term FFVs. There are no dedicated ethanol vehicles now. As an ethanol refueling infrastructure is developed, dedicated vehicles using high-ethanol blends — such as E90 — may be introduced. No fuel economy and emission testing data are available for dedicated E90 vehicles. We assume that they will achieve greater fuel economy and emissions benefits than E85 FFVs.

Table 4.41 Changes in Fuel Economy and Emissions by Use of E85 Flexible-Fuel Vehicles[a]

		Change Relative to CG (%)						
Source	Vehicle Model	Economy (mpgeg)	Exhaust VOCs	Evap. VOCs	CO	NO_x	CH_4	N_2O
AQIRP[b]	1992 GM 3.1-L Lumina FFV	3.3	-28.1	NA[c]	-68.8	-60.3	NA	NA
	1994 Ford 3.0-L Taurus FFV	-4.7	14.2	NA	21.5	-56.6	NA	NA
	1993 Chrysler 2.5-L Acclaim FFV	0.5	-5.9	NA	58.2	-42.7	NA	NA
NREL[d]	1993 Chevrolet 3.1-L Lumina FFV	-0.2	-23.9	-2.4	-18.2	-27.4	62.8	NA
EPA Certification	1996 Ford 3.0-L Taurus FFV	NA	-57.1	NA	-35.7	0.0		
	1997 Ford 3.0-L Taurus FFV	NA	98.2	NA	74.8	-9.0		
	1998 Ford 3.0-L Taurus FFV	10.0	-14	NA	-7.0	-7.0		
Chrysler Corp.	1998 3.3L minivan: 50k mi	NA	0	NA	39.5	-3.8		
	1998 3.3L minivan: 100k mi	NA	12	NA	111.7	68.6		

[a] Values in % relative to GVs using CG, under the FTP cycle.

[b] From AQIRP (1995c).

[c] NA = not available.

[d] From Kelly et al. (1996b). Fuel economy and emission changes by E85 are relative to CARFG2, not CG.

At present, more than 1.2 × 10^9 gal of ethanol is used a year in the United States in the form of gasohol and oxygenated fuel (E10). In evaluating fuel-cycle energy and emissions impacts of using E10, we assume no changes in gasoline-equivalent fuel economy and emissions between gasoline and E10 except for CO and evaporative VOC emissions. Because E10 generally has a higher RVP than gasoline, we assume a 10% increase in evaporative emissions by E10 relative to CG.

4.9.6 Liquefied Petroleum Gas Vehicles

Although a large number of LPGVs are in use, a limited number of fuel economy and emission tests have been conducted for them. Table 4.42 presents LPGV testing results. Ford offers an LPG bi-fuel Econoline van and an LPG bi-fuel F-Series pickup truck. But most LPGVs on the road have been converted from GVs. Usually, aftermarket conversions have higher emissions than OEM-produced vehicles. In our analysis, we assume bi-fuel aftermarket conversions as well as bi-fuel OEM LPGVs for the near term and dedicated LPGVs for the long term.

4.9.7 Other Vehicle Types

Tested fuel economy and emissions data are scarce for other vehicle types. This section summarizes our assumptions for these other vehicle types.

Significant technological advances have been made for CIDI diesel engines in the last several years. CIDI engines can achieve a 35% improvement in gasoline-equivalent fuel

Table 4.42 Changes in Fuel Economy and Emissions by Use of Liquified Petroleum Gas Vehicles[a,b]

		Change Relative to CG (%)					
Source	**Vehicle Model**	**Economy (mpgeg)**	**Exhaust VOCs**	**CO**	**NO_x**	**CH_4**	**N_2O**
Battelle[c]	1992 Chevy 5.7-L van	-10.4	28.6	-54.5	-71.9	66.5	-71.0
	1992 Ford 4.8-L van	-5.8	39.3	-24.1	12.1	23.2	269.5
NREL[d]	1994 Ford F150 pickup	NA[e]	362.4	-57.2	0.0	NA	NA
	1994 Ford Taurus	NA	43.0	-62.5	677.6	NA	NA
EPA Certification	1996 GM 4.3-L Caprice	NA	-14.4	68.4	88.2	NA	NA
	1998 Ford 5.4-L F-Series pickup	NA	-35.3	83.3	50.0	NA	NA

[a] All the tested LPGVs here were converted from GVs.

[b] Values in % relative to GVs using CG, under the FTP cycle.

[c] From Battelle Memorial Institute (1995a,b) and Orban et al. (1995). Emissions were tested in three phases as vehicle mileage accumulated. The values here are the average of the results from the three phases.

[d] From Motta et al. (1996). The vehicles are aftermarket conversions with IMPCO conversion kit.

[e] NA = not available.

economy relative to conventional GVs. Advances have also been made recently in spark-ignition, direct-injection (SIDI) engines. Toyota began to sell an SIDI gasoline car in Japan in MY 1998. The Toyota has a fuel economy improvement of 30% (under the Japanese 10/15-mode cycle) relative to CG cars (*Automotive Engineering* 1997). The fuel economy gain by the car as measured under the U.S. FTP may be smaller. A fuel economy gain of 25% is assumed for SIDI gasoline vehicles under the FTP cycle in our study. Direct-injection engines usually have high NO_x emissions. These vehicles will have to meet the same emission standards as conventional vehicles in the United States. We assume that emission control technologies for direct-injection engines will improve so that their emissions will be comparable to those of counterpart conventional vehicles.

Fuel economy improvements for grid-connected HEVs under the grid electric model will be the same as those for EVs. We assume that near-term electric cars and LDT1 will achieve a fuel economy 3.5 times that of conventional GVs, and electric LDT2 will achieve a fuel economy 3 times that of conventional GVs. The fuel economy of near-term HEVs under the internal combustion engine (ICE) mode is assumed to be 50% higher than the fuel economy of conventional GVs. This assumption is based on Argonne's simulations of HEVs. Emissions of HEVs during ICE operations are assumed to be 20% lower than those of conventional GVs, on a per-mile basis.

For the long-term EVs, we assume improved fuel economy relative to that of near-term EVs. In particular, we assume that long-term electric cars and LDT1 will achieve a gasoline-equivalent fuel economy 4 times that of conventional GVs, and electric LDT2 will achieve a fuel economy 3.5 times that of conventional GVs. We assume long-term HEVs under ICE operations will achieve a 75% improvement in fuel economy relative to conventional GVs. In comparison, a recent report by Thomas et al. (1998) presented an mpg improvement of 25–70% for NG-fueled HEVs and 39–93% for diesel-fueled HEVs.

On the basis of our review of existing literature, we assume that hydrogen (H_2)-fueled FCVs achieve a fuel economy 2.5 times that of GVs. For methanol-fueled FCVs, the increase in fuel economy is calculated from the improvement of H_2-fueled FCVs and the efficiency of on-board methanol processors. Although both steam reforming and partial oxidation reforming can be used to produce H_2 from methanol, we assume that steam reforming is used because the technology is already mature, and partial oxidation does not offer great benefits for methanol reforming relative to steam reforming. We assume that methanol-fueled FCVs achieve a fuel economy twice that of GVs. In comparison, Thomas et al. (1998) estimated that methanol FCVs may achieve a fuel economy improvement of only 45–62%.

Recent developments in partial oxidation reforming of H_2-containing fuels show promise for using other fuels such as gasoline, NG, and ethanol to produce H_2 on board a vehicle. These fuels are generally more difficult to reform than methanol. We assume that FCVs fueled with gasoline, NG, and ethanol via partial oxidation reforming achieve a 75% improvement in fuel economy over that of conventional GVs. This estimate is 25% less than the fuel economy improvement by methanol FCVs. In comparison, Thomas et al. (1998) estimated a fuel economy improvement for gasoline-fueled FCVs of 40%.

For conventional diesel vehicles fueled with CD (the currently available low-sulfur diesel), we assume a gain of 10% in gasoline-equivalent fuel economy, relative to conventional GVs. Emissions of CD vehicles are estimated by using EPA's Mobile 5b and Part 5.

With lower sulfur and aromatic content, RFD is proposed for use in CIDI engines to meet stringent NO_x and PM emission standards such as ultra-low emission vehicle (ULEV) standards. The likely specifications of RFD are unknown now. In a study to estimate the potential costs of producing RFD, McNutt and Hadder (1998) assumed an RFD with 30 ppm sulfur content by weight and 10% aromatics content by volume. We use this RFD specification in our analysis. We assume that CIDI engines fueled with RFD may be able to meet Tier 2 NO_x (0.07 g/mi) and PM (0.01 g/mi) emission standards.

Besides RFD, the following other fuels have been proposed for use in CIDI engines: DME, FTD, and biodiesel. DME has a high cetane number (55–60, compared to 40–55 for CD) and contains no sulfur and aromatics. Use of DME can reduce emissions of NO_x and PM drastically. Emissions of VOCs and CO may be increased slightly by using DME. However, tests have shown that the majority of HC emissions from DME combustion are unburned DME and methane (Mikkelsen et al. 1996). We assume, then, that CH_4 emissions are increased by 100% by use of DME relative to use of CD. Because there is no DME production for transportation use at present, we consider that it is a long-term technology option. Limited emissions testing has been conducted for use of DME in compression-ignition engines. Table 4.43 presents emissions testing results of vehicles fueled with DME.

FTD has a high cetane number and contains virtually no sulfur and aromatics, making it an excellent fuel for CIDI engines with significant potential for lowering NO_x and PM emissions.

Table 4.43 Changes in Fuel Economy and Emissions by Use of DME in Compression-Ignition Engines[a]

		Change Relative to CD (%)				
Source	Vehicle Model	Economy (mpgeg)	Exhaust VOC	CO	NO_x	PM
Mikkelsen et al. (1996)	Single-cylinder engine	0	0	40	-90	-95
Christensen et al. (1997)	1.0-L engine for boat applications	NA[b]	95	100	-50	-95
Fleisch et al. (1995a)	Navistar 7.3-L engine	0	NA	NA	-15 to -65	-60
Fleisch and Meurer (1995b)	HDTs	NA	0	NA	-57	-75
Sorenson and Mikkelsen (1995)	A small engine	0	0	NA	-75	-93

[a] Values in percent relative to use of CD.

[b] NA = not available.

After reviewing limited fuel economy and emissions test data for diesel engines fueled with FTD, Gaines et al. (1998) assumed that FTD achieves a 25% reduction in NO_x emissions relative to CD. Because FTD contains no aromatics, we expect that it is more economical to blend FTD with CD and use the blend in CIDI engines. We assume a blend of 50% FTD and 50% CD by volume (FT50). We also assume that, relative to RFD, FT50 achieves a 10% reduction in PM emissions; fuel economy and emissions of other pollutants for RFD and FT50 are assumed to be the same.

Biodiesel has been proposed for use in CI engines to reduce NO_x and PM emissions. Because it is renewable, biodiesel helps reduce GHG emissions. The cost of producing biodiesel (mainly driven by soybean feedstock cost) is prohibitively high. We assume that biodiesel will be used in a 20% blend with CD (BD20). We assume the same fuel economy and emission performance for BD20 as for FT50.

4.9.8 Summary

Many of the vehicles included in the summary of testing results for AFVs presented in the previous section were tested under laboratory-controlled conditions to understand the emission differences between AFVs and comparable GVs. Several caveats are associated with this method of summarizing AFV relative emission changes.

First, many more vehicle models are available for some of the AFV types (such as CNGVs) than for others. The emissions results for the types for which significant testing data are available are more reliable than the results for the less readily available types.

Second, there are tradeoffs among pollutants, emissions, and fuel economy, as well as other vehicle performance attributes for the various vehicle technologies. Individual vehicle models can be designed for different intended tradeoffs — for example, to minimize emissions or to maximize performance. So researchers cannot average results from different vehicle models together to generate average results for a vehicle type.

The third caveat is that, although tests within an individual study may follow a strictly consistent test procedure (e.g., an AFV type and a baseline GV may be tested the same way), testing procedures and calibrations may not be exactly the same among different studies. Thus, emission testing results for AFVs from one study usually cannot be compared with emission testing results for GVs from a different study. This is why, in this study, we calculated emission changes for each individual study in order to evaluate AFV emission changes.

Often, AFV emission benefits are cited in statements based on a single study or a single vehicle model. As the above summary reveals, emission changes can vary considerably among studies and vehicle models for the same vehicle type. Also, data from tests that were conducted on vehicle models that are already out of production should not be given significant consideration in evaluating the effects of future vehicle models. In assuming future AFV emission impacts, we rely heavily on the results from models still in production.

Some believe that, because future vehicles will be subject to the same emission standards, the emissions of different vehicle types should be the same or similar. If manufacturers designed vehicles only to meet emission standards, this would be a valid argument. But because different fuels have different inherit emission performance characteristics, manufacturers can meet a set of standards with a low-emission fuel with less difficulty than with a high-emission fuel. Also, California regulates vehicle emissions with several emission categories (e.g., LEV, ULEV, super ultra-low-emission vehicle [SULEV]), and EPA will probably regulate emissions with different vehicle bins (see Table 6.3) subject to different emission standards. That is, future emission standards will provide incentives to manufacturers to produce vehicles with different emission levels. Alternative-fueled vehicles, with inherently low emissions, will certainly be produced at emission levels lower than those of baseline gasoline or diesel vehicles.

The fuel economies of available AFV models are published in the *MY 1999 Fuel Economy Guide* released by DOE and EPA (1998a). On the basis of data contained in the guide, we estimate fuel economy changes of MY 1999 AFV models (Table 4.44). Fuel economy changes in the table are based on on-road adjusted fuel economy. The table shows that, while ethanol FFVs have small gains in fuel economy, CNGVs have large fuel economy penalties.

Tables 4.45 and 4.46 present the default values of fuel economy and emission change rates used in the GREET model for the vehicle types included in GREET. Fuel economy and emission changes by alternative fuels and advanced technologies are assumed for passenger cars and LDT1 as one group and for LDT2 as another group. Alternative transportation fuels and advanced vehicle technologies are separated into near-term and long-term technologies. Near-term technologies are already available. Long-term technologies will be likely become available in 10 years. Baseline GVs fueled with CG for near-term technologies are assumed to

Table 4.44 Fuel Economy Changes of 1999 MY Alternative-Fuel Vehicle Models[a,b]

	FUDS Cycle (%)	Highway Cycle (%)	55/45 Cycle (%)
Ethanol Vehicles			
Chrysler Caravan 3.3-L (L4)	1	5	3
Ford Ranger 3.0-L (L4, 4WD)	3	-2	1
Ford Ranger 3.0-L (M5, 4WD)	7	2	5
Ford Ranger 3.0-L (L4, 2WD)	-1	2	0
Ford Ranger 3.0-L (M5, 2WD)	7	3	5
Ford Taurus 3.0-L (L4)	3	0	2
CNG Vehicles			
Ford Contour 2.0-L (L4, bi-fuel)	-26	-26	-26
Ford Crown Victoria 4.6-L (L4)	-18	-17	-18
Ford F-250 Pickup 5.4-L (L4)	-15	-12	-14
Ford E-250 Van 5.4-L (L4, bi-fuel)	-15	-17	-16

[a] Based on data contained in DOE and EPA 1998a.

[b] Fuel economy changes by AFVs are relative to fuel economy of comparable gasoline vehicle models. L4 = automatic lockup 4-speed, M5 = manual 5-speed, 4WD = 4-wheel drive, 2WD = 2-wheel drive.

meet federal Tier 1 emissions standards. In Table 4.45, emission reductions by RFG2 are based on emission performance of California RFG2. Fuel economy and emission changes for bi-fuel and dedicated CNGVs rely on testing results of recently introduced vehicle models. FFVs fueled with M85, E85, and LPG are generally assumed to have emissions similar to those of vehicles fueled by RFG2. The fuel economy and performance of HEVs powered by grid electricity are assumed to be the same as the fuel economy and performance of battery-powered EVs. Emissions performance of HEVs powered by on-board engines is assumed to be similar to that of vehicles fueled by RFG2. The emissions performance of diesel-engine vehicles is assumed to be similar across vehicle types.

For the long-term technology options, baseline GVs fueled with RFG2 are assumed to meet the proposed federal Tier 2 standards. Few data are available for long-term technology options. Through our research, we sought inputs from experts on these technology options. The assumptions made here reflect expert opinions together with our understanding of the potential of each technology option. So the assumptions for long-term technology options are more speculative than those for near-term technology options. In general, we assume that long-term technologies will be able to meet the newly proposed Tier 2 standards. If a technology has inherently low emission potential, we assume emission reductions relative to Tier 2 standards.

Few data on the fuel economy of long-term technology options are available. Recently, Stodolsky et al. (1999) completed a study on advanced vehicle technologies. The study was widely reviewed. Fuel economy changes for SIDI vehicles, SIDI HEVs, CIDI vehicles, CIDI HEVs, and FCVs in this study are derived primarily from the Stodolsky study.

Table 4.46 presents fuel economy and emission changes for LDT2. In most cases, fuel economy and emission changes are the same as those for passenger cars and LDT1. In a few

Table 4.45 Changes in Fuel Economy and Emissions by Various Vehicle Types: Passenger Cars and Light-Duty Trucks 1[a]

	Change (%)							
Vehicle Type	Economy (mpgeg)	Exhaust VOC	Evap. VOC	CO	NO_x	Exhaust PM_{10}[b]	CH_4	N_2O
Near-Term Technologies: % Relative to National Low-Emission Vehicle (NLEV) GVs Fueled with CG (except as noted)								
GVs: RFG2[c]	0	-10	-30	-20	-5	-5	-8	0
CNGVs: bi-fuel[d]	-10	-40	-50	-20	0	-90	900	-40
CNGVs: dedicated	-7	-60	-90	-30	-10	-95	900	-20
LPGVs: dedicated	0	-20	-90	-25	-10	-90	30	0
FFVs: M85[d]	5	-15	-15	-25	-10	-60	-50	0
FFVs: E85[d]	5	-15	-15	-25	-10	-60	50	0
GVs: E10	0	0	20	-20	0	0	0	0
EVs	200	-100	-100	-100	-100	-100	-100	-100
Grid-independent SIDI HEVs: RFG2	90	-10	-40	-20	0	20	0	0
Grid-connected SIDI HEVs: RFG2[e]								
Grid operation	200	-100	-100	-100	-100	-100	-100	-100
ICE operation	80	-10	-40	-20	0	20	0	0
CIDI vehicles: CD[f]	35	NN[g]	NN	NN	NN	NN	NN	NN
Grid-independent CIDI HEVs: CD[h]	100	0	0	0	0	0	0	0
Long-Term Technologies: % Relative to Tier 2 GVs Fueled with RFG2 (except as noted)								
CNGVs/LNGVs: dedicated	5	-10	-90	-20	0	-80	400	-50
LPGVs: dedicated	10	0	-90	-20	0	-80	10	0
M90-dedicated vehicles	10	0	0	0	0	-40	-50	0
E90-dedicated vehicles	10	0	0	0	0	-40	50	0
SIDI vehicles: RFG2	25	0	-10	0	0	40	0	0
SIDI vehicles: M90	25	0	-10	0	0	0	-50	0
SIDI vehicles: E90	25	0	-10	0	0	0	50	0
Grid-independent SIDI HEVs: RFG2	90	0	-30	0	0	20	0	0
Grid-independent SI HEVs: CNG/LNG	70	-10	-90	-20	0	-50	400	-50
Grid-independent SI HEVs: LPG	70	0	-90	-20	0	-50	10	0
Grid-independent SIDI HEVs: M90	90	0	-30	0	0	-15	-50	0
Grid-independent SIDI HEVs: E90	90	0	-30	0	0	-15	50	0
Grid-connected SIDI HEVs: RFG2[e]								
Grid operation	300	-100	-100	-100	-100	-100	-100	-100
ICE operation	85	0	-30	0	0	20	0	0
Grid-connected SI HEVs: CNG/LNG[e]								
Grid operation	300	-100	-100	-100	-100	-100	-100	-100
ICE operation	65	-10	-90	-20	0	-50	400	-50
Grid-connected SI HEVs: LPG[e]								
Grid operation	300	-100	-100	-100	-100	-100	-100	-100
ICE operation	65	0	-90	-20	0	-50	10	0
Grid-connected SIDI HEVs: M90[e]								
Grid operation	300	-100	-100	-100	-100	-100	-100	-100
ICE operation	85	0	-30	0	0	-15	-50	0
Grid-connected SIDI HEVs: E90[e]								
Grid operation	300	-100	-100	-100	-100	-100	-100	-100
ICE operation	85	0	-30	0	0	-15	50	0

Table 4.45 (Cont.)

Vehicle Type	Change (%) Economy (mpgeg)	Exhaust VOC	Evap. VOC	CO	NO_x	Exhaust PM_{10}[b]	CH_4	N_2O
CIDI vehicles: RFD[i]	50	NN	NN	NN	NN	NN	NN	NN
CIDI vehicles: DME[h]	50	-30	NN	0	0	-30	100	0
CIDI vehicles: FT50[h]	50	0	NN	0	0	-20	0	0
CIDI vehicles: BD20[h]	50	0	NN	0	0	-10	0	0
Grid-independent CIDI HEVs: RFD[h]	130	0	NN	0	0	0	0	0
Grid-independent CIDI HEVs: DME[h]	130	-30	NN	0	0	-30	100	0
Grid-independent CIDI HEVs: FT50[h]	130	0	NN	0	0	-20	0	0
Grid-independent CIDI HEVs: BD20[h]	130	0	NN	0	0	-10	0	0
Grid-connected CIDI HEVs: RFD								
Grid operation	300	-100	-100	-100	-100	-100	-100	-100
ICE operation	120	0	0	0	0	0	0	0
Grid-connected CIDI HEVs: DME[e]								
Grid operation	300	-100	-100	-100	-100	-100	-100	-100
ICE operation	120	-30	0	0	0	-30	100	0
Grid-connected CIDI HEVs: FT50[e]								
Grid operation	300	-100	-100	-100	-100	-100	-100	-100
ICE operation	120	0	0	0	0	-20	0	0
Grid-connected CIDI HEVs: BD20[e]								
Grid operation	300	-100	-100	-100	-100	-100	-100	-100
ICE operation	120	0	0	0	0	-10	0	0
EVs	300	-100	-100	-100	-100	-100	-100	-100
FCVs: H_2	200	-100	-100	-100	-100	-100	-100	-100
FCVs: MeOH	160	-80	-60	-80	-80	-100	-80	-80
FCVs: RFG2	100	-80	-30	-80	-80	-100	-80	-80
FCVs: EtOH	100	-80	-60	-80	-80	-100	-80	-80
FCVs: CNG	100	-80	-95	-80	-80	-100	100	-80

[a] A positive value means an increase; a negative value means a decrease; and a zero value means no change.

[b] Very few data on PM emissions from AFVs are available. Emissions reduction rates here are primarily our own assumptions.

[c] Based on Mobile 5b runs for CG and FRFG2. In running Mobile 5b, NLEV Stage 2 on-board diagnosis system (OBDII), and enhanced I/M were included.

[d] For vehicles using both gasoline and an alternative fuel, only use of the alternative fuel is evaluated. Use of gasoline in these vehicles is assumed to produce the same energy and emissions results as baseline GVs.

[e] For grid-connected HEVs, the results of grid and ICE operations are combined with VMT share of each operation within GREET. We assumed that, on average, 30% of the VMT by HEVs is with grid electricity, and the remaining 70% is with ICE operations.

[f] Emissions from CIDI engine vehicles fueled with CD are estimated with Mobile 5b and Part 5. The fuel economy changes for these vehicles are relative to those of conventional GVs.

[g] NN = not needed. Mobile 5b-estimated values will be used.

[h] For these vehicle types, fuel economy changes are relative to GVs and emission changes are relative to CIDI diesel engines. Furthermore, near-term technologies are relative to CIDI engines fueled with CD that meet NLEV standards, and long-term technologies are relative to CIDI engines fueled with RFD that meet proposed Tier 2 standards.

[i] Emissions of CIDI engine vehicles fueled with RFD are estimated on the basis of the assumption that RFD will help conventional CI engines meet Tier 2 standards. Their fuel economy changes are relative to those of conventional GVs.

Table 4.46 Changes in Fuel Economy and Emissions by Various Vehicle Types: Light-Duty Trucks 2[a]

	Change (%)							
Vehicle Type	Economy (mpgeg)	Exhaust VOC	Evap. VOC	CO	NO_x	Exhaust PM_{10}[b]	CH_4	N_2O
Near-Term Technologies: % Relative to Tier 1 GVs Fueled with CG (except as noted)								
GVs: RFG2[c]	0	-10	-30	-20	-5	-5	-8	0
CNGVs: bi-fuel[d]	-10	-50	-50	-30	0	-90	900	-40
CNGVs: dedicated	-7	-70	-90	-40	0	-95	900	-20
LPGVs: dedicated	0	-30	-90	-25	-15	-90	30	0
FFVs: M85[d]	0	-25	-25	-25	-15	-60	-50	0
FFVs: E85[d]	0	-25	-25	-25	-15	-60	50	0
GVs: E10	0	0	20	-30	0	0	0	0
EVs	200	-100	-100	-100	-100	-100	-100	-100
Grid-independent SIDI HEVs: RFG2	90	-25	-40	-25	-15	20	0	0
Grid-connected SIDI HEVs: RFG2[e]								
Grid operation	200	-100	-100	-100	-100	-100	-100	-100
ICE operation	80	-25	-40	-25	-15	20	0	0
CIDI vehicles: CD[f]	35	NN[g]	NN	NN	NN	NN	NN	NN
Grid-independent CIDI HEVs: CD[h]	100	0	0	0	0	0	0	0
Long-Term Technologies: % Relative to Tier 2 GVs Fueled with RFG2 (except as noted)								
CNGVs/LNGVs: dedicated	0	-20	-90	-20	0	-80	400	-50
LPGVs: dedicated	5	0	-90	-20	0	-80	10	0
M90-dedicated vehicles	5	0	0	0	0	-40	-50	0
E90-dedicated vehicles	5	0	0	0	0	-40	50	0
SIDI vehicles: RFG2	25	0	-10	0	0	40	0	0
SIDI vehicles: M90	25	0	-10	0	0	0	-50	0
SIDI vehicles: E90	25	0	-10	0	0	0	50	0
Grid-independent SIDI HEVs: RFG2	90	0	-30	0	0	20	0	0
Grid-independent SI HEVs: CNG/LNG	70	-10	-90	-20	0	-50	400	-50
Grid-independent SI HEVs: LPG	70	0	-90	-20	0	-50	10	0
Grid-independent SIDI HEVs: M90	90	0	-30	0	0	-15	-50	0
Grid-independent SIDI HEVs: E90	90	0	-30	0	0	-15	50	0
Grid-connected SIDI HEVs: RFG2[e]								
Grid operation	250	-100	-100	-100	-100	-100	-100	-100
ICE operation	85	0	-30	0	0	20	0	0
Grid-connected SI HEVs: CNG/LNG[e]								
Grid operation	250	-100	-100	-100	-100	-100	-100	-100
ICE operation	65	-10	-90	-20	0	-50	400	-50
Grid-connected SI HEVs: LPG[e]								
Grid operation	250	-100	-100	-100	-100	-100	-100	-100
ICE operation	65	0	-90	-20	0	-50	10	0
Grid-connected SIDI HEVs: M90[e]								
Grid operation	250	-100	-100	-100	-100	-100	-100	-100
ICE operation	85	0	-30	0	0	-15	-50	0
Grid-connected SIDI HEVs: E90[e]								
Grid operation	250	-100	-100	-100	-100	-100	-100	-100
ICE operation	85	0	-30	0	0	-15	50	0

Table 4.46 (Cont.)

	Change (%)							
Vehicle Type	Economy (mpgeg)	Exhaust VOC	Evap. VOC	CO	NO_x	Exhaust PM_{10}[b]	CH_4	N_2O
CIDI vehicles: RFD[i]	50	NN	NN	NN	NN	NN	NN	NN
CIDI vehicles: DME[h]	50	-30	NN	0	0	-30	100	0
CIDI vehicles: FT50[h]	50	0	NN	0	0	-15	0	0
CIDI vehicles: BD20[h]	50	0	NN	0	0	-10	0	0
Grid-independent CIDI HEVs: RFD[h]	130	0	NN	0	0	0	0	0
Grid-independent CIDI HEVs: DME[h]	130	-30	NN	0	0	-30	100	0
Grid-independent CIDI HEVs: FT50[h]	130	0	NN	0	0	-15	0	0
Grid-independent CIDI HEVs: BD20[h]	130	0	NN	0	0	-10	0	0
Grid-connected CIDI HEVs: RFD[e]								
Grid operation	250	-100	-100	-100	-100	-100	-100	-100
ICE operation	120	0	0	0	0	0	0	0
Grid-connected CIDI HEVs: DME[e]								
Grid operation	250	-100	-100	-100	-100	-100	-100	-100
ICE operation	120	-30	0	0	0	-30	100	0
Grid-connected CIDI HEVs: FT50[e]								
Grid operation	250	-100	-100	-100	-100	-100	-100	-100
ICE operation	120	0	0	0	0	-15	0	0
Grid-connected CIDI HEVs: BD20[e]								
Grid operation	250	-100	-100	-100	-100	-100	-100	-100
ICE operation	120	0	0	0	0	-10	0	0
EVs	250	-100	-100	-100	-100	-100	-100	-100
FCVs: hydrogen	200	-100	-100	-100	-100	-100	-100	-100
FCVs: MeOH	160	-80	-60	-80	-80	-100	-80	-80
FCVs: RFG2	100	-80	-30	-80	-80	-100	-80	-80
FCVs: EtOH	100	-80	-60	-80	-80	-100	-80	-80
FCVs: CNG	100	-80	-95	-80	-80	-100	100	-80

[a] A positive value means an increase; a negative value means a decrease; and a zero value means no change.

[b] Very few data on PM emissions from AFVs are available. Emissions reduction rates here are primarily our own assumptions.

[c] Assumed to be the same as for cars and LDT1.

[d] For vehicles using both gasoline and an alternative fuel, only use of the alternative fuel is evaluated. Use of gasoline in these vehicles is assumed to produce the same energy and emissions results as baseline GVs.

[e] For grid-connected HEVs, the results of grid and ICE operations are combined with VMT share of each operation within GREET. It is assumed that, on average, 30% of the VMT by HEVs is with grid electricity, and the remaining 70% is with ICE operations.

[f] Emissions of CIDI engine vehicles fueled with CD are estimated with Mobile 5b and Part 5. The fuel economy changes for these vehicles are relative to those of conventional GVs.

[g] NN = not needed. Mobile 5b-estimated values will be used.

[h] For these vehicle types, fuel economy changes are relative to GVs, and emission changes are relative to CIDI diesel engines. Furthermore, near-term technologies are relative to CIDI engines fueled with CD that meet NLEV standards, and long-term technologies are relative to CIDI engines fueled with RFD that meet proposed Tier 2 standards.

[i] Emissions of CIDI engine vehicles fueled with RFD are estimated based on the assumption that RFD will help CIDI engines meet the proposed Tier 2 standards. Their fuel economy changes are relative to those of conventional GVs.

cases, the changes are different, for example, the reductions in the actual *amount* of fuels used and the actual emissions are larger for LDT2 than for passenger cars and LDT1, simply because per-mile fuel consumption and emissions are larger.

As stated in Section 3, emissions of SO_x for each vehicle type are calculated by assuming that all sulfur contained in a given fuel is converted to SO_2. Emissions of CO_2 for all vehicle types are calculated by subtracting the carbon contained in emissions of VOC, CO, and CH_4 from the carbon contained in a given fuel. For vehicles fueled with E85, E90, E10, and BD20, the amount of CO_2 emissions from the carbon contained in the portion of ethanol and biodiesel are treated as being zero, because these CO_2 emissions originally come from the atmosphere through the photosynthesis process during farming of corn, biomass, and soybeans.