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^oC, 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°C helps produce predominately middle distillates and wax; an operating temperature of 330–350°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

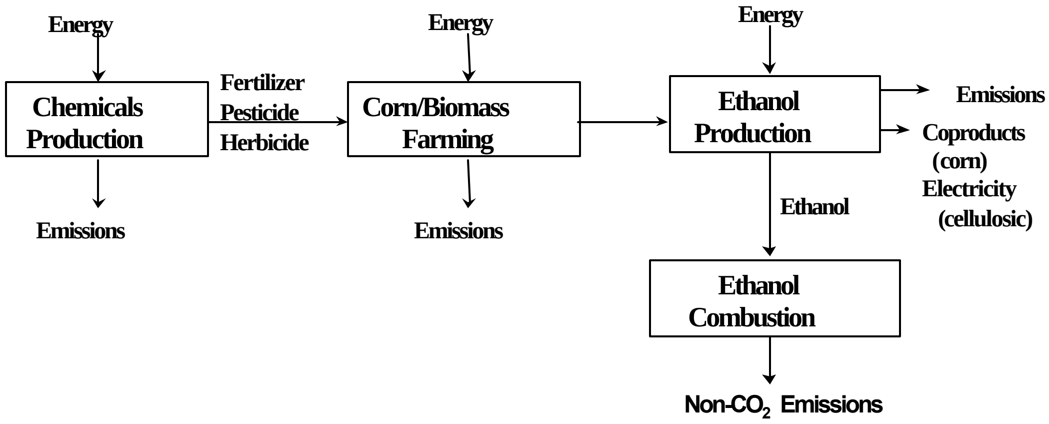

Figure 4.1 Stages Included in Renewable Ethanol Cycles

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.

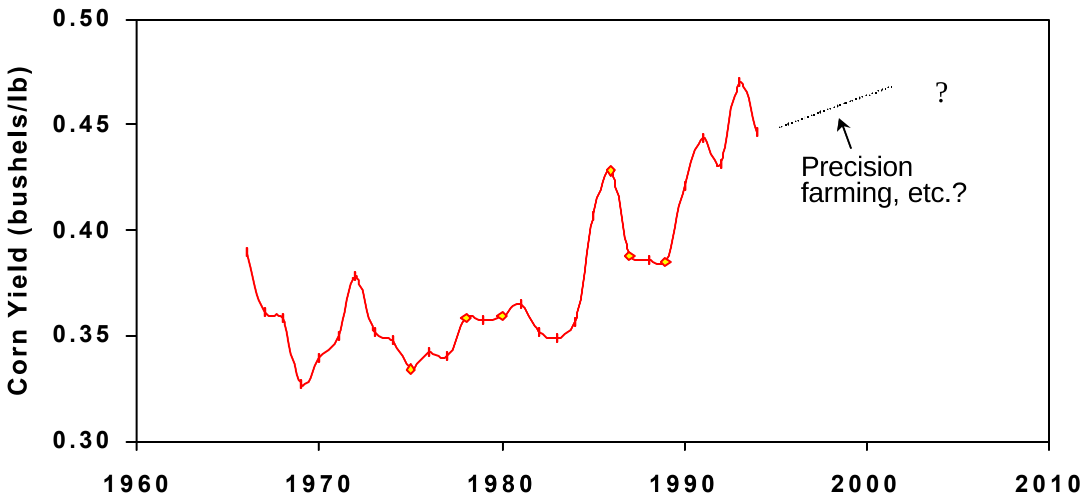

Figure 4.2 Historical Corn Productivity: Bushels of Corn Produced per Pound of Fertilizer Applied (3-year moving average; nitrogen, phosphate, and potash fertilizers are included here, on the basis of data provided by Shapouri [1997])

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).

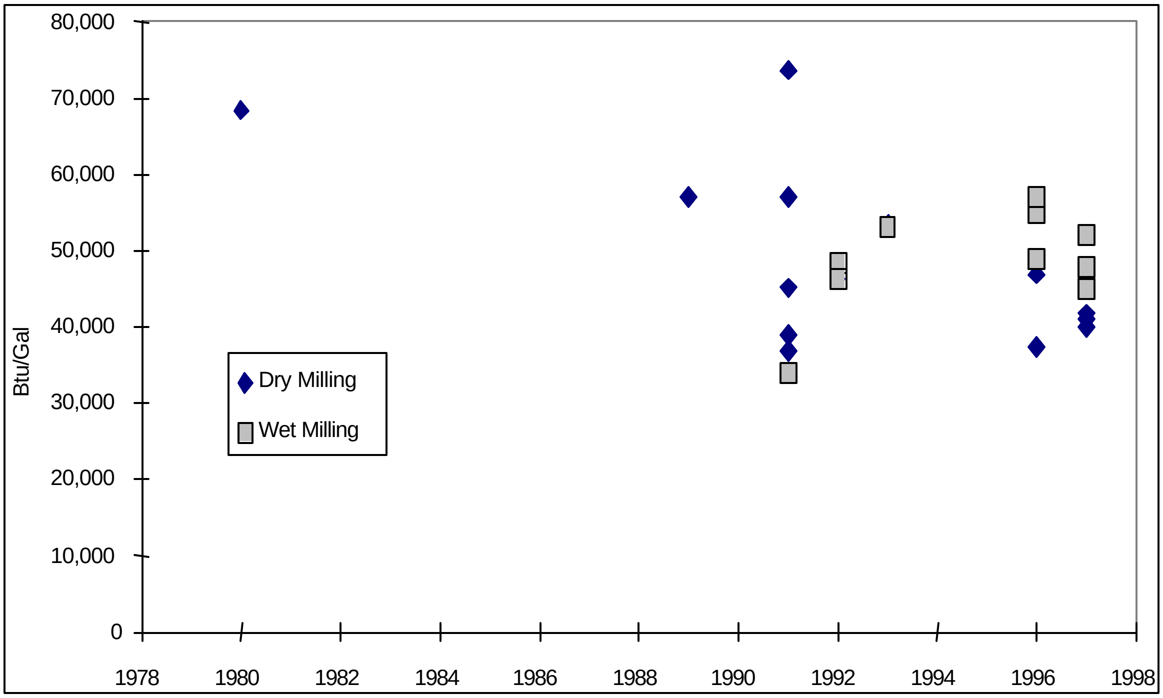

Figure 4.3 Historical Estimates of Energy Use in Ethanol Plants

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%.