4.2.3 Noncombustion Emissions during Natural Gas Processing and Fuel Production

SO_x emissions are generated during the 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 calculated that the SO_x emission rate from NG sweetening is 2.226 g/10^6 Btu of NG processed.

Because the carbon ratio of methanol is higher than that of NG (primarily CH_4), the process of converting 10^6 Btu of NG to 10^6 Btu of methanol results in a net carbon absorption. We assumed here that the additional carbon in the 10^6 Btu of methanol comes from NG burned during the conversion process. The carbon absorption rate of the methanol conversion process is estimated here as 12,495 g/10^6 Btu methanol produced. This CO_2 emissions value is subtracted from the CO_2 emissions value calculated for NG combustion in methanol plants.

Emissions of SO_x are generated during LPG production because NG contains about 0.0007% sulfur but LPG contains no sulfur. The model assumes that all sulfur contained in NG is converted into SO_2 (which accounts for most SO_x emissions) and that SO_x emissions produced this way make up 0.155 g/10^6 Btu of LPG produced. SO_x emissions are also generated during hydrogen production; the GREET model assumes an SO_x emission rate of 0.155 g/10^6 Btu of hydrogen produced.

Because of the elimination of carbon in hydrogen, the conversion of NG to hydrogen produces excess CO_2 emissions. We estimated that the conversion process produces CO_2 at 59,777 g/10^6 Btu of hydrogen produced. This CO_2 emissions value is added to the CO_2 emissions value for fuel combustion in hydrogen production plants.

4.3 ETHANOL PRODUCTION CYCLES

The GREET model includes three ethanol-producing fuel cycles: corn to ethanol, woody biomass to ethanol, and herbaceous biomass to ethanol. While the technology involved in converting corn to ethanol is mature, the technology for converting biomass (both woody and herbaceous) to ethanol has not been demonstrated commercially. The large-scale production of biomass to obtain ethanol also has yet to be demonstrated. So, while the corn-to-ethanol cycle can be treated as a near-term option, the other cycles (herbaceous and woody biomass to ethanol) should be treated as long-term options.

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 fertilizer used, rather than the energy efficiencies of the production process. So, by inputting the amount of fuel used, the amount of fertilizer used, and the amount of energy used to produce fertilizer, we can calculate the energy efficiencies for the production of corn, woody biomass, and herbaceous biomass. However, direct use of the former values (amount of fuel and fertilizer used) in the GREET model makes the assumptions more explicit and easier to interpret.

4.3.1 Fuel and Fertilizer Use for Corn and Biomass Production

Table 4 presents the fuel and fertilizer usage values assumed in the GREET model for production and transportation of corn and biomass. To calculate emissions generated during manufacturing at fertilizer plants, the energy consumption for fertilizer production is needed. On the basis of information in Delucchi (1993) and Marland and Turhollow (1991), the GREET model assumes values of 62, 9, and 8 Btu/g of fertilizer nitrogen, phosphate (P_2O_5), and potash (K_2O), respectively. The breakdowns of the energy consumption into different energy sources were obtained from Delucchi (1991).

Calculated emissions and energy consumption per bushel of corn and per dry ton of biomass are converted into emissions and energy consumption/10^6 Btu of energy produced. For this conversion, we assumed 2.6 gal of ethanol per bushel of corn (on the basis of information in Delucchi [1993] and Marland and Turhollow [1991]). The conversion for biomass is completed by using the energy content of woody and herbaceous biomass.

TABLE 4 Fuel and Fertilizer Usage for Production and Transportation of Corn and Biomass

Usage Values for Corn and Biomass Production	Corn (per bushel)	Woody Biomass (per dry ton)	Herbaceous Biomass (per dry ton)
Fuel used for production (Btu)	24,000[a]	43,706[b]	45,056[b]
Fertilizer use (g):			
Nitrogen	567.5[a]	1,276.8[b]	4,596.8[b]
P_2O_5	261.1[a]	754.8[b]	3,405[b]
K_2O	306.5[a]	754.8[b]	3,405[b]
Fuel used for transportation (Btu)	5,600[a]	41,500[a]	41,500[a]

[a] From Delucchi (1993).

[b] From NREL et al. (1991). In calculating these numbers, we assumed a biomass production rate of 8 dry ton/acre; this value was based on NREL et al. (1991) and McLaughlin (1993).

4.3.2 Energy Efficiencies for Other Stages

Emissions and energy consumption of other ethanol-cycle stages are calculated on the basis of energy balance. Table 5 presents the data sources and energy efficiency values of other stages used in the GREET model.

4.3.3 Noncombustion Emission Sources

NO_x and N_2O Emissions from Fertilizer Decomposition. Decomposition of nitrogen fertilizer produces emissions of NO_x (primarily NO) and N_2O. On the basis of data presented in Delucchi (1993) and Williams et al. (1992), we calculated emissions values of 33.193 g N_2O and

TABLE 5 Energy Efficiencies of Ethanol Production Stages (%)

	Production Stage			
Data Source	Corn to Ethanol	Woody Biomass to Ethanol	Herbaceous Biomass to Ethanol	Ethanol T&S&D
GREET	50.0[a]	55.0[b]	65.6[b]	97.8
Delucchi (1991)	42.0	65.0	NE[c]	97.7
NREL (1992)	NE	NE	NE	98.2
Ecotraffic (1992)	NE	53.2	NE	99.0
Bentley (1992)	47.0	NE	NE	93.1
Darrow (1994a)	63.6	NE	NE	98.4
Acurex (1995)	42.3	49.3	NE	NE
Lynd (1996)	NE	46.0-61.4	NE	NE

[a] The conversion efficiency for corn to ethanol does not take into account the energy contained in by-products from ethanol plants. The issue of by-products is addressed by dividing the emissions and energy use involved in ethanol production and upstream processes between ethanol and by-products. (See Section 4.3.4 for a detailed discussion.)

[b] The conversion efficiency for woody and herbaceous biomass to ethanol does not take into account the energy contained in the electricity co-generated in biomass ethanol plants, which is addressed separately.

[c] NE = Not estimated.

13.747 g NO_x per bushel of corn produced, 74.684 g N_2O and 30.931 g NO_x per dry ton of woody biomass produced, and 268.861 g N_2O and 222.703 g NO_x per dry ton of herbaceous biomass produced.

Noncombustion Emissions during Ethanol Production. In the United States, more ethanol is currently produced from corn in wet milling facilities than in dry milling facilities. Handling and pretreatment of corn and biomass at ethanol plants produce noncombustion PM_{10} emissions. Noncombustion VOC emissions result from fermentation of corn and biomass, treatment of wastes and by-products, and storage of ethanol at ethanol plants. On the basis of emission factors for wet milling ethanol plants presented in EPA's AP-42 document (EPA 1995), a noncombustion PM_{10} emission factor of 56.158 g/10^6 Btu of ethanol is estimated for corn-to-ethanol plants. A noncombustion PM_{10} emission rate of 5.757 g and a VOC emission rate of 1.873 g/10^6 Btu of ethanol was estimated for woody biomass-to-ethanol plants. A PM_{10} emission rate of 5.486 g and a VOC emission rate of 1.748 g/10^6 Btu of ethanol was estimated for herbaceous biomass-to-ethanol plants. These estimates were based on data presented in NREL et al. (1991). A noncombustion VOC emission rate of 1.8 g/10^6 Btu of ethanol is assumed for corn-to-ethanol plants.

4.3.4 Other Critical Assumptions

Shares of Products in Corn-to-Ethanol Plants. Corn-to-ethanol plants produce by-products that can be used for animal food or other purposes. So total emissions from ethanol plants and from upstream corn production need to be divided between ethanol and other by-products. On the basis of data presented in Delucchi (1993), the energy share of ethanol accounts for about 55% of the total energy contained in all products from corn-based ethanol plants. So 55% of emissions and energy used in ethanol plants and in upstream corn production processes are allocated to ethanol; the remaining 45% are allocated to other by-products. Alternatively, the market share values of different products could be used to allocate emissions and energy use among products from corn-to-ethanol plants.

For biomass-based ethanol plants, no by-products are assumed — except that combustion of biomass through co-generation facilities in ethanol plants generates electricity and provides the heat required for ethanol production. Data in NREL et al. (1991) imply that the electricity credit was 0.062 Btu of electricity per Btu of ethanol produced for woody biomass-to-ethanol plants and 0.038 Btu for herbaceous biomass-to-ethanol plants. Lynd et al. (1996) estimated an electricity credit of 0.101-0.142 Btu per Btu of ethanol produced in biomass-to-ethanol plants, depending on the progress of biomass-to-ethanol conversion technologies. In the GREET model, the electricity credit is assumed to be 0.1 Btu for woody biomass-to-ethanol plants and 0.06 Btu for herbaceous biomass-to-ethanol plants. These are equivalent to 2.22 and 1.34 kilowatt-hours (kWh)/gal of ethanol produced. The electricity generated can be exported to the electric grid. Emissions credits for the generated electricity are addressed in the GREET model by taking into account the amount of electricity generated and the average emissions associated with electricity generation.

CO_2 Emissions of Biomass Combustion. In this study, we assume that biomass will be burned in biomass-to-ethanol plants to provide heat needed for ethanol production. While combustion of biomass 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.

4.4 COAL TO ELECTRICITY

This section presents data for coal mining and coal transportation to power plants. Coal combustion in power plants and electricity transmission and distribution are discussed in Section 4.7.

4.4.1 Energy Efficiencies

On the basis of data presented in Delucchi (1991), Wang and Delucchi (1992), and Darrow (1994a), an energy efficiency of 99.3% is assumed in the GREET model for coal mining; an efficiency of 99.4% is assumed for coal transportation.

4.4.2 Noncombustion Emissions

During the coal mining process, a large amount of CH_4 emissions that are contained with the coal in coal beds is released. Data presented in Delucchi (1993) were used in this study to calculate a CH_4 release rate of 381.271 g/10^6 Btu of coal mined.

Coal is usually cleaned at mining sites to remove impurities such as sulfur, ash, and rock. By using information contained in the AP-42 document (EPA 1995), we calculated the following emission rates for coal cleaning: 2.169 g/10^6 Btu of coal processed for VOCs, 3.037 g/10^6 Btu for NO_x, 1.952 g/10^6 Btu for PM_{10}, and 5.423 g/10^6 Btu for SO_x.

4.5 URANIUM TO ELECTRICITY

Three stages of the uranium-to-electricity cycle (uranium mining, transportation, and enrichment) cause emissions because fuel combustion is involved in these stages. On the basis of data presented in Delucchi (1991), this study assumes an energy efficiency of 99.5% for uranium mining, 99.9% for uranium transportation, and 95.8% for uranium enrichment. No noncombustion emissions are assumed for this cycle.

4.6 LANDFILL GASES TO METHANOL

EPA (1991) estimates that 3,000 to 6,000 landfills currently produce landfill gases. Flares at the landfill sites are used to burn the released methane. Recently, TeraMeth Industries, based in California, developed a compact, mobile facility to produce methanol from landfill gases. TeraMeth is in the final stage of obtaining a permit to build a methanol production plant in southern California. The proposed facility will have a production capacity of 17,000 gal/day of methanol. Nationwide, there are about 600 landfills that generate large quantities of gases for methanol production; the GREET model includes this cycle of producing methanol from landfill gases.

4.6.1 Energy Efficiencies

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

4.6.2 Emission Credits of Methanol Production

Because the production of methanol from landfill gases eliminates the practice of burning landfill gases in flares, the process of converting landfill gases to methanol earns emission credits equal to the amount of emissions otherwise produced from combustion of landfill gases. Using data presented by the SCAQMD (1994), we calculated an emissions credit of 5.582 g/10^6 Btu of methanol produced for VOCs, 106.1 g/10^6 Btu for CO, 21.6 g/10^6 Btu for NO_x, 35.36 g/10^6 Btu for

PM_{10}, 7.393 g/10^6 Btu for SO_x, 706.8 g/10^6 Btu for CH_4, and 178,715 g/10^6 Btu for CO_2. These emission credits, subtracted from emissions of the landfill gas-to-methanol cycle, result in negative upstream emissions. On the other hand, as discussed later, emissions of on-vehicle methanol combustion are considered in calculating emissions from ICEVs fueled with the methanol that is produced from landfill gases.

4.7 ELECTRICITY GENERATION

Of the various power plants, those fueled by residual oil, NG, and coal produce emissions at the plant sites. Nuclear power plants do not produce air emissions at plant sites, but emissions are associated with upstream uranium production and preparation stages. The GREET model calculates emissions associated with electricity generation from residual oil, NG, coal, and uranium. Electricity generated from hydropower, solar energy, wind, and geothermal energy is treated as having zero emissions; these sources are categorized together in one group.

4.7.1 Combustion Technologies

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

4.7.2 Power Plant Conversion Efficiencies

Table 6 presents power-plant conversion efficiencies used in the GREET model and in some other studies. Among the technologies presented, oil-, NG-, and coal-fired boilers; NG-fired turbines; and nuclear plants are current technologies. Advanced NG combined-cycle turbines and integrated gasification combined-cycle processes are future technologies. Both current and future technologies are included in the GREET so that the model can simulate the impacts of using EVs and HEVs in the future, when both current and future technologies are used to generate electricity.

TABLE 6 Energy Conversion Efficiencies of Electric Power Plants (%)

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

[a] NE = not estimated.

4.7.3 Electric Generation Mixes

The electric generation mix greatly affects the fuel-cycle emissions of EVs and HEVs. Because this mix differs significantly across the United States, use of EVs and HEVs can have very different emission impacts in different regions. Table 7 presents the electric generation mix in various U.S. regions (Figure 1 shows these regions). The data show that on the west coast and in the northeastern United States, where EV use is adopted or proposed, electricity is primarily generated from clean sources such as nuclear power, hydropower, and NG. Each of these electric generation mix sets can be input into the GREET model to simulate EV or HEV emission impacts.

4.8 VEHICLE OPERATIONS

The current version of the GREET model is designed to estimate fuel-cycle energy use and emissions for light-duty vehicles only. Efforts are currently being undertaken to incorporate heavy-duty vehicles. The model includes 12 vehicle types fueled with different fuels: RFG vehicles, LSD vehicles, CNG vehicles, M85 vehicles, M100 vehicles, LPG vehicles, E85 vehicles, E100 vehicles, EVs, HEVs, hydrogen fuel-cell vehicles, and methanol fuel-cell vehicles. RFG-fueled vehicles are treated as the baseline.

In estimating fuel-cycle energy use and emissions for HEVs, the GREET model assumes a generic HEV type. Although various units powered by different fuels are proposed for use in HEVs, the model includes the HEV type equipped with a gasoline engine. Energy to drive HEVs is provided from grid electricity and from on-board power generation units. Overall energy use and emissions for HEVs are calculated by using the average energy use and emissions of the grid electricity mode and the gasoline engine mode of HEVs weighted by miles traveled in each mode.

The GREET model assumes proton-exchange membrane fuel-cells for both hydrogen- and methanol-fueled FCVs. For methanol-fueled FCVs, the model assumes that methanol is reformed into hydrogen through an on-board reformer.

4.8.1 Vehicle Fuel Economy and Component Efficiencies

A fuel economy of 30 MPG is assumed in the GREET model for the baseline GV. Users can change baseline GV fuel economy on the basis of their own assumptions. Fuel economy for each of the other 11 vehicle types is calculated from baseline GV fuel economy and relative improvement in fuel economy between GVs and the other types. Table 8 presents default values for relative fuel economy improvements in the 11 vehicle types. Improvements in MPG values for diesel, CNG, M85, M100, LPG, E85, E100, and EVs are based primarily on Wang et al. (1993) and

TABLE 7 Electric Generation Mix of Various U.S. Regions in 2005 (%)[a]

Region	Energy Source: Coal	Oil	NG	Nuclear	Others
East Central (ECAR)	83.6	0.5	5.1	8.3	2.4
Texas (ERCOT)	38.2	2.5	47.9	9.3	2.0
Mid-Atlantic (MAAC)	44.8	4.3	15.8	30.7	4.4
Illinois and Wisconsin (MAIN)	58.7	0.5	1.6	37.3	1.9
Mid-Continent (MAPP)	72.2	0.1	0.6	17.6	9.5
New York State (NY)	14.4	22.0	18.5	18.7	26.4
New England w/o New York (NE)	14.3	25.5	13.6	31.3	15.5
Florida (FL)	34.0	22.4	24.0	14.3	5.3
Southeast w/o Florida (STV)	57.2	1.4	5.6	27.8	8.0
Southwest (SPP)	55.3	1.4	27.8	10.7	4.8
Northwest (NWP)	27.2	0.1	15.2	1.8	55.6
Rocky Mountains and Arizona (RA)	57.8	0.4	24.6	6.7	10.5
California and Southeast Nevada (CNV)	19.6	3.1	31.8	19.9	25.6
Northeastern United States Average[b]	29.4	14.1	16.0	27.7	12.9
U.S. Average	50.9	3.4	14.9	18.9	11.9

[a] Calculated from data presented in EIA 1995.

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

Acurex (1995). As the table shows, no MPG improvements in fuel efficiency are assumed for CNG and LPG vehicles. These vehicles will be heavier than baseline GVs because of the heavy on-board storage cylinders or tanks required to fuel them; the additional vehicle weight may offset efficiency gains from fuel combustion. The improvement in fuel economy for HEVs powered with grid electricity is assumed to be the same as that for EVs. The increased MPG for HEVs in the gasoline engine mode is based on the estimated fuel economy of various HEV designs presented in Sperling and Burke (1994). Fuel economy increases for hydrogen FCVs are from Acurex (1995); for methanol FCVs, the increase is calculated from the improvement of hydrogen FCVs and the efficiency of on-board methanol reformers. On the basis of simulation results presented by General Motors Corporation (1994), an energy efficiency of 77% is assumed in the GREET model for methanol reformers.

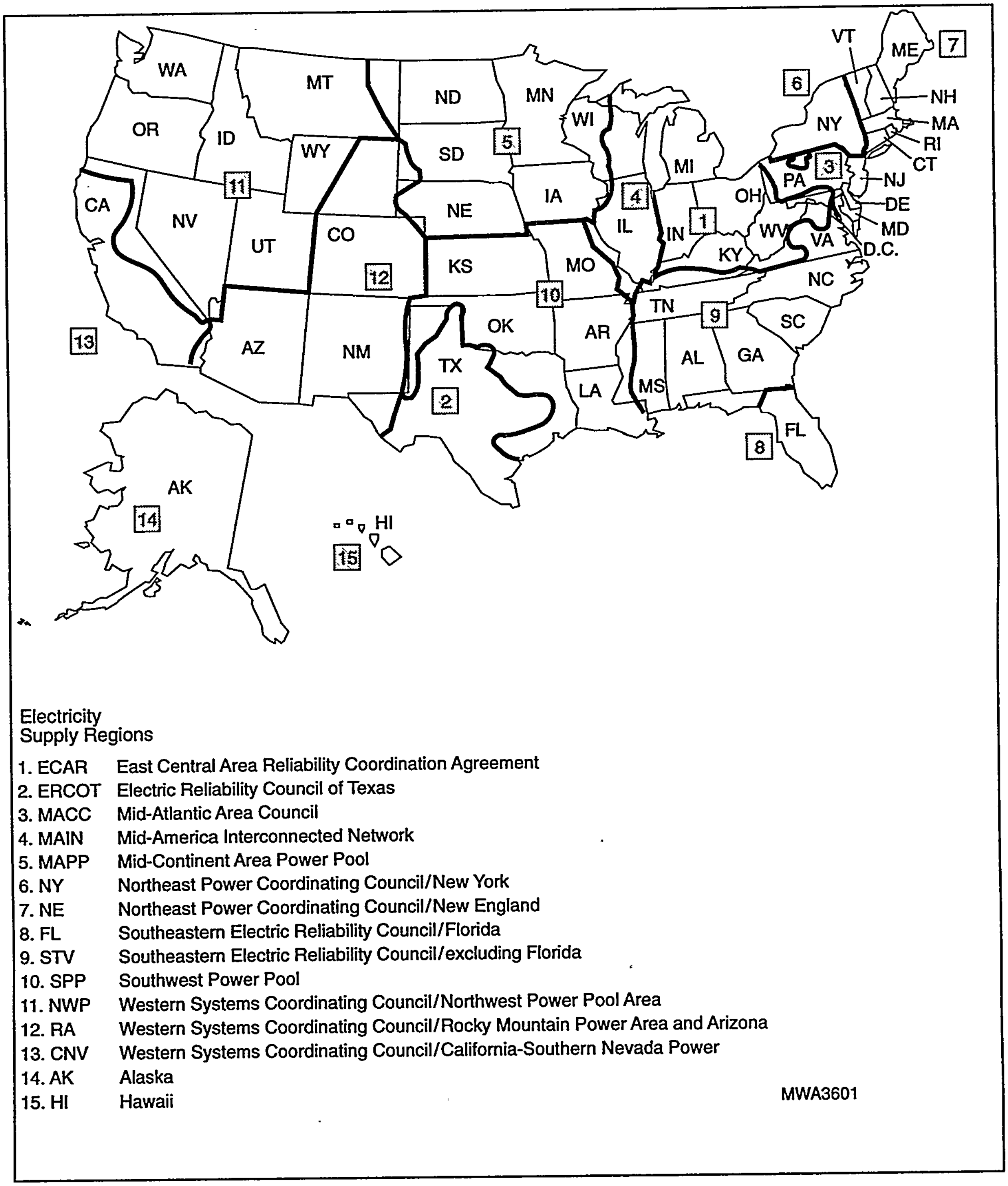

FIGURE 1 Electricity Supply Regions (from EIA 1995)

4.8.2 Emissions

TABLE 8 Fuel Economy Improvements of 11 Vehicle Types[a]

Vehicle Type	Fuel Economy Improvement (% increase in MPG)
Diesel	10
CNG	0
M85	4
M100	5
LPG	0
E85	4
E100	5
EVs	200
HEVs: grid electricity	200
HEVs: gasoline engines	37
Hydrogen FCVs	100
Methanol FCVs	54

[a] Percentages given are relative to baseline GVs.

Emissions from vehicle operations are calculated for nine pollutants or sources: exhaust and evaporative VOCs, CO, NO_x, exhaust PM_{10}, brakewear and tirewear PM_{10}, SO_x , CH_4, N_2O, and CO_2. VOC emissions (both exhaust and evaporative), CO, and NO_x for GVs and diesel vehicles are calculated by using EPA's Mobile5a model. Emissions of PM_{10} (both exhaust and brakewear/tirewear) for GVs and diesel vehicles are calculated by using EPA's PART5 model. We estimated CH_4 emission for GVs and diesel vehicles by taking the difference between HC emissions and NMHC emissions, both of which we calculated with the Mobile5a model. Emissions of N_2O for GVs and diesel vehicles are adopted from Delucchi (1993).

Emissions from other vehicle types are calculated from emissions of baseline GVs and emission change rates of other vehicle types relative to baseline GVs. Table 9 presents the default values of emission change rates used in the GREET model. Changes in emissions of criteria pollutants for CNG, M85, M100, LPG, E85, and E100 vehicles are based on information presented in Wang et al. (1993). Changes in emissions of CH_4 and N_2O for these vehicle types are based on information presented in Delucchi (1993). Vehicle operation emissions of EVs and HEVs powered by grid electricity are assumed to be zero. Emissions of exhaust VOCs, CO, and NO_x for HEVs in the gasoline engine mode are based on information presented in Sperling and Burke (1994). Emissions of evaporative VOCs, exhaust PM_{10}, CH_4, and N_2O for HEVs in the gasoline engine mode are assumed to be 80% of those for baseline GVs. We estimated emissions from methanol reformers for methanol FCVs on the basis of data presented in Creveling (1992). Brakewear and tirewear PM_{10} emissions are assumed to be constant among different vehicle types.

Emissions of SO_x for each vehicle type are calculated by assuming that all sulfur contained in a given fuel is converted to SO_2. Emissions of CO_2 for all vehicle types are calculated by subtracting the carbon contained in emissions of VOCs, CO, and CH_4 from the carbon contained in a given fuel. For E85 and E100 vehicles, the amount of CO_2 emissions from the carbon contained in ethanol is treated as zero, because these CO_2 emissions originally come from the atmosphere through the photosynthesis process during corn and biomass production.

TABLE 9 Emission Changes of Vehicle Operations for Various Vehicle Types[a]

	Emission Change (%)						
Vehicle Type	Exhaust VOCs	Evaporative VOCs	CO	NO_x	Exhaust PM_{10}	CH_4	N_2O
CNG	45	0	60	95	0	2,000	100
M85	85	35	85	95	10	65	100
M100	75	35	80	90	0	50	100
LPG	55	0	70	95	0	100	100
E85	85	35	85	95	10	65	100
E100	75	35	80	90	0	50	100
EVs	0	0	0	0	0	0	0
HEVs: grid electricity	0	0	0	0	0	0	0
HEVs: gasoline engines	16	80	50	100	80	80	80
Hydrogen FCVs	0	0	0	0	0	0	0
Methanol FCVs	10	35	10	10	0	0	0

[a] Values represent percent of emissions from baseline GVs.