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GREET 1.5 — Transportation Fuel-Cycle Model

Volume 1: Methodology, Development, Use, and Results

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GREET 1.5 — Transportation Fuel-Cycle Model

Volume 1: Methodology, Development, Use, and Results

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GREET — *G*reenhouse Gases, *R*egulated *E*missions, and *E*nergy Use in *T*ransportation

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Notation

Acronyms and Abbreviations

AEO98	1998 Annual Energy Outlook
AFV	alternative-fuel vehicle
AQIRP	Auto/Oil Air Quality Improvement Research Program
ATR	autothermal reforming
BD	biodiesel
BD20	mixture of 20% biodiesel and 80% conventional diesel by volume
CAAA	Clean Air Act Amendments
CAFE	corporate average fuel economy
CARB	California Air Resources Board
CARFG1	California Phase 1 reformulated gasoline
CARFG2	California Phase 2 reformulated gasoline
CD	conventional diesel
CG	conventional gasoline
CH_4	methane
CI	compression ignition
CI-AFV	compression-ignition alternative fuel vehicles
CIDI	compression ignition, direct injection
CNG	compressed natural gas
CNGV	compressed natural gas vehicle
CO	carbon monoxide
CO_2	carbon dioxide
DDGS	distillers' dried grains and solubles
DGS	distillers' grains and solubles
DI	direct injection
DME	dimethyl ether
DMM	dimethoxy methane
DOE	U.S. Department of Energy
DV	diesel vehicle
E10	mixture of 10% ethanol and 90% gasoline by volume
E85	mixture of 85% ethanol and 15% gasoline by volume
E90	mixture of 90% ethanol and 10% gasoline by volume
E95	mixture of 95% ethanol and 5% gasoline by volume
EF	emission factor
EIA	Energy Information Administration
EPA	U.S. Environmental Protection Agency
ETBE	ethyl tertiary butyl ether
EtOH	ethanol
EV	electric vehicle

EVTECA	Electric Vehicle Total Energy Cycle Analysis
FCV	fuel-cell vehicle
FFV	flexible-fuel vehicle
FG	flared gas
FRFG1	federal Phase 1 reformulated gasoline
FRFG2	federal Phase 2 reformulated gasoline
FTD	Fischer-Tropsch diesel
FT50	mixture of 50% Fischer-Tropsch diesel and 50% diesel by volume
FTP	federal test procedure
FUDS	federal urban driving schedule
GC	grid connected
GHG	greenhouse gas
GI	grid independent
GREET	**G**reenhouse Gases, **R**egulated **E**missions, and **E**nergy Use in **T**ransportation
GRI	Gas Research Institute
GV	gasoline vehicle
GVW	gross vehicle weight
GVWR	gross vehicle weight rating
GWP	global warming potential
H_2	hydrogen
H_2S	hydrogen sulfide
HC	hydrocarbon
HCHO	formaldehyde
HDT	heavy-duty truck
HEV	hybrid electric vehicle
HHV	high heating value
HLDT	heavy light-duty truck
IGCC	integrated gasification with combined cycle
ICE	internal combustion engine
ICEV	internal combustion engine vehicle
I/M	inspection and maintenance
INEEL	Idaho National Engineering and Environmental Laboratory
IPCC	Intergovernment Panel on Climate Change
K_2O	potassium oxide (potash)
LCA	life-cycle analysis
LDGT1	light-duty gasoline truck 1 with a gross vehicle weight of up to 6,000 lb
LDGT2	light-duty gasoline truck 2 with a gross vehicle weight of 6,001–8,500 lb
LDT	light-duty truck with gross vehicle weight of 0–8,500 lb
LDT1	light-duty truck 1 with gross vehicle weight of 0–6,000 lb
LDT2	light-duty truck 2 with gross vehicle weight of 6,001–8,500 lb
LEBS	low emission boiler systems
LEV	low-emissions vehicle
LHV	low heating value
LLDT	light light-duty truck
LNG	liquefied natural gas
LPG	liquefied petroleum gas

LPGV	liquefied petroleum gas vehicle
M85	mixture of 85% methanol and 15% gasoline by volume
M90	mixture of 90% methanol and 10% gasoline by volume
M95	mixture of 95% methanol and 5% gasoline by volume
M100	100% methanol by volume (pure methanol)
MeOH	methanol
MSW	municipal solid waste
MTBE	methyl tertiary butyl ether
MY	model year
N	elemental nitrogen
N_2O	nitrous oxide
N_2O-N	nitrogen in N_2O
Na/S	sodium/sulfur
NaOH	sodium hydroxide
NG	natural gas
NH_3	ammonia
NLEV	National Low-Emission Vehicle
NMHC	nonmethane hydrocarbon
NMOG	nonmethane organic gas
NO	nitrogen oxide
NO_3^-	nitrate
NO_3^--N	nitrogen in nitrate
NO_x	nitrogen oxides
NREL	National Renewable Energy Laboratory
NSPS	New Source Performance Standards
OBDII	stage 2 on-board diagnosis system
OEM	original equipment manufacturer
PFB/CC	pressurized fluidized-bed combustion with combined cycle
PM	particulate matter
PM_{10}	particulate matter with diameters of 10 micrometers or less
POX	partial oxidation
P_2O_5	phosphate
REP05	representative cycle No. 5
RFD	reformulated diesel
RFG	reformulated gasoline
ROG	reactive organic gas
RVP	Reid vapor pressure
SCAQMD	South Coast Air Quality Management District
SI	spark ignition
SI-AFV	spark-ignition alternative fuel vehicle
SIDI	spark-ignition, direct-injection
SMR	steam methane reforming
SO_2	sulfur dioxide
SO_x	sulfur oxides
SULEV	super ultra-low emission vehicle
T50	temperature at which 50% of gasoline is vaporized

T90	temperature at which 90% of gasoline is vaporized
T&S	transportation and storage
T&S&D	transportation, storage, and distribution
TAME	tertiary amyl methyl ether
TECA	total energy-cycle analysis
THC	total hydrocarbon
ULEV	ultra-low emission vehicle
USDA	U.S. Department of Agriculture
VFV	variable-fuel vehicle
VMT	vehicle miles traveled
VOC	volatile organic compound
ZnO	zinc oxide
ZnS	zinc sulfide

Units of Measure

bbl	barrel
Btu	British thermal unit
bu	bushel
d	day
ft^3	cubic foot
g	gram
gal	gallon
GJ	giga joule
ha	hectare
kcal	kilocalorie
kg	kilogram
kWh	kilowatt-hour
L	liter
lb	pound
mi	mile
mpg	miles per gallon
mpgeg	miles per gasoline-equivalent gallon
nm^3	normal cubic meter
ppm	parts per million
ppmw	parts per million weight
psi	pounds per square inch
scf	standard cubic foot
yr	year

Foreword

This report is a revision to a previous Argonne National Laboratory report entitled *GREET 1.0 — Transportation Fuel Cycles Model: Methodology and Use* (dated June 1996). The 1996 report documented the methodologies, key assumptions, and results of the development and use of the first version of the **G**reenhouse Gases, **R**egulated **E**missions, and **E**nergy Use in **T**ransportation (GREET) fuel-cycle model developed at Argonne National Laboratory. Since then, the GREET 1.0 model has been significantly expanded and improved. The model has evolved into three modules (each comprising a series of versions): the first module covers fuel-cycle energy and emissions of passenger cars and light-duty trucks (GREET 1.1, GREET 1.2, etc.); the second covers vehicle-cycle energy and emissions of passenger cars and light-duty trucks (GREET 2.1, GREET 2.2, etc.); and the third module covers fuel-cycle energy and emissions of heavy-duty trucks (gross vehicle weight over 8,500 pounds) (GREET 3.1, GREET 3.2, etc.).

In September 1998, GREET 1.4 was released with a draft report documenting its development. The model was posted at Argonne's transportation website at www.transportation.anl.gov/ttrdc/publications/papers_reports/techassess/ta_papers.html, and the draft report was sent to reviewers for comment. Since then, significant revisions and expansions have been made to both the report and the model. The current version of the 1-series model is GREET 1.5. This report documents the development and use of GREET 1.5. It includes portions of the 1996 report that have few changes (e.g., the introduction and review of previous fuel-cycle studies) to eliminate the need for readers to refer to the previous report. It also reflects reviewers' comments on the August 1998 draft report.

This report is separated into two volumes. Volume 1 presents GREET 1.5 development and use and discussions of fuel-cycle energy and emission results for passenger cars. Volume 2, comprising four appendices, presents detailed fuel-cycle results for passenger cars, light-duty trucks 1, and light-duty trucks 2.

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Abstract

This report documents the development and use of the most recent version (Version 1.5) of the **G**reenhouse Gases, **R**egulated **E**missions, and **E**nergy Use in **T**ransportation (GREET) model. The model, developed in a spreadsheet format, estimates the full fuel-cycle emissions and energy use associated with various transportation fuels and advanced vehicle technologies for light-duty vehicles. The model calculates fuel-cycle emissions of five criteria pollutants (volatile organic compounds, carbon monoxide, nitrogen oxides, particulate matter with diameters of 10 micrometers or less, and sulfur oxides) and three greenhouse gases (carbon dioxide, methane, and nitrous oxide). The model also calculates total energy consumption, fossil fuel consumption, and petroleum consumption when various transportation fuels are used. The GREET model includes the following cycles: petroleum to conventional gasoline, reformulated gasoline, conventional diesel, reformulated diesel, liquefied petroleum gas, and electricity via residual oil; natural gas to compressed natural gas, liquefied natural gas, liquefied petroleum gas, methanol, Fischer-Tropsch diesel, dimethyl ether, hydrogen, and electricity; coal to electricity; uranium to electricity; renewable energy (hydropower, solar energy, and wind) to electricity; corn, woody biomass, and herbaceous biomass to ethanol; soybeans to biodiesel; flared gas to methanol, dimethyl ether, and Fischer-Tropsch diesel; and landfill gases to methanol. This report also presents the results of our analysis of fuel-cycle energy use and emissions associated with alternative transportation fuels and advanced vehicle technologies to be applied to passenger cars and light-duty trucks.

Section 1
Introduction

Alternative transportation fuels and advanced vehicle technologies are being promoted to help solve urban air pollution problems, reduce greenhouse gas (GHG) emissions, and relieve U.S. dependence on imported oil. To accurately and adequately evaluate the energy and emission effects of alternative fuels and vehicle technologies, researchers must consider emissions and energy use from upstream fuel production processes as well as from vehicle operations. This research area is especially important for technologies that employ fuels with distinctly different primary energy sources and fuel production processes, for which upstream emissions and energy use can be significantly different.

Studies were conducted to estimate fuel-cycle emissions and energy use associated with various transportation fuels and vehicle technologies. The results of those studies were influenced by the assumptions made by individual researchers regarding technology development, emission controls, primary fuel sources, fuel production processes, and many other factors. Because different methodologies and parametric assumptions were used by different researchers, it is difficult to compare and reconcile the results of different studies and to conduct a comprehensive evaluation of fuel-cycle emissions and energy use. Computer models for calculating emissions and energy use are needed to allow analysts and researchers to test their own methodologies and assumptions and make accurate comparisons of different technologies.

The Center for Transportation Research at Argonne National Laboratory has been conducting fuel-cycle analyses for various transportation fuels and vehicle technologies for the past 15 years. In 1996, with funding from the U.S. Department of Energy's (DOE's) Office of Transportation Technologies, Argonne developed a spreadsheet-based fuel-cycle model. The goal was to provide a simple computer tool that would allow researchers to evaluate fuel-cycle energy and emission impacts of various transportation technologies. Since its creation, the model has been used extensively by researchers at Argonne and other institutions to calculate the fuel-cycle energy requirements of and emissions from various alternative transportation fuels and advanced vehicle technologies. The model has evolved significantly since its introduction.

This report describes the development and use of the latest version of the **G**reenhouse Gases, **R**egulated **E**missions, and **E**nergy Use in **T**ransportation (GREET) model (Version 1.5). The GREET 1.5 model calculates, for a given fuel/transportation technology combination, the fuel-cycle emissions of five criteria pollutants: volatile organic compounds (VOCs), carbon monoxide (CO), nitrogen oxides (NO_x), sulfur oxides (SO_x), and particulate matter with diameters of 10 micrometers or less (PM_{10}). The model also calculates the fuel-cycle emissions of greenhouse gases — primarily carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) — and the fuel-cycle consumption of total energy, fossil fuel, and petroleum. The model is designed to allow researchers to readily input their own assumptions and generate fuel-cycle energy and emission results for specific fuel/technology combinations.

This report comprises two volumes. Volume 1 addresses three areas of GREET development and use: (1) review of past and ongoing fuel-cycle studies; (2) methodologies, parametric assumptions, and data sources for the assumptions used in the GREET model; and (3) fuel-cycle energy and emission results for various fuel/technology combinations for passenger cars, as calculated by using the GREET model. Volume 2 contains four appendices that provide detailed fuel-cycle energy and emission results for passenger cars, light-duty trucks 1, and light-duty trucks 2.

Section 2
Review of Previous Fuel-Cycle Studies

This section describes the methods and assumptions used in previous studies conducted to estimate fuel-cycle emissions and energy use.

2.1 Delucchi 1991, 1993

In 1991, Delucchi completed a study to estimate fuel-cycle emissions of GHGs for various transportation fuels and for electricity generation (Delucchi 1991, 1993). The GHGs considered in the study included CO_2, CH_4, CO, N_2O, NO_x, and nonmethane organic gases (NMOGs). In addition to studying the emissions and energy use of the fuel-cycle stages (ranging from primary energy recovery to on-vehicle fuel combustion), Delucchi examined the emissions and energy use involved in the manufacture of motor vehicles, maintenance of transportation systems, manufacture of materials used in major energy facilities, and changes in land use caused by the production of biofuels. Through his study, Delucchi developed a model of calculating GHG emissions. The model included the following fuel cycles: petroleum to gasoline, petroleum to diesel, petroleum to liquefied petroleum gas (LPG), natural gas (NG) to methanol, NG to compressed natural gas (CNG), NG to liquefied natural gas (LNG), NG to LPG, coal to methanol, wood to methanol, corn to ethanol, wood to ethanol, nuclear energy to hydrogen, solar energy to hydrogen, and electricity generation from various fuels.

To calculate GHG emissions for a specific fuel-cycle stage, Delucchi first estimated the total amount of energy burned at that stage. He allocated the total amount of energy to different fuels (e.g., residual oil, NG, electricity, coal), then estimated combustion-causing emissions of GHGs (except CO_2) by using emission factors. He calculated CO_2 emissions by using a carbon balance approach: the carbon contained in CO, CH_4, and NMOG emissions was subtracted from all available carbon in a combusted fuel, and the remaining carbon was assumed to be oxidized to CO_2. Besides combustion-causing emissions, Delucchi included GHG emissions from fuel losses such as leakage and evaporation. He combined emissions of all GHGs together with their global warming potentials (GWPs) and presented the results of fuel-cycle, vehicle life-cycle GHG emissions in CO_2-equivalent emissions per mile of travel.

To derive process energy efficiencies and energy source shares for total energy consumption, Delucchi relied primarily on Energy Information Administration (EIA) surveys on manufacturing energy consumption. Delucchi estimated the emission factors of various energy combustion processes primarily on the basis of information in the fourth edition of the U.S. Environmental Protection Agency (EPA) AP-42 document (EPA 1988).

Using his model, Delucchi estimated GHG emissions for the year 2000 from a baseline gasoline car with a fuel economy of 30 miles per gallon (mpg). He generally assumed energy efficiency improvements for alternative-fuel vehicles (AFVs) relative to gasoline vehicles (GVs). To address uncertainties in future energy production processes and vehicle technologies, Delucchi designed various scenarios representing potential improvements in fuel production efficiencies, GWPs of GHGs, relative efficiencies of AFVs, and regional differences in fuel production.

From his study, Delucchi drew the following general conclusions:

- Coal-based fuels generally increased GHG emissions;
- Slight to moderate reductions in GHG emissions resulted from using NG-based fuels (e.g., methanol, CNG, LNG, electricity from NG, and LPG);
- Use of woody biomass-based ethanol greatly reduced GHG emissions;
- Corn-based ethanol could increase GHG emissions;
- Use of solar energy via electricity or hydrogen nearly eliminated GHG emissions; and
- Use of nuclear energy via electricity or hydrogen greatly reduced GHG emissions.

Delucchi's was the most comprehensive and extensive study of energy-cycle GHG emissions. The study has been widely cited. A substantial amount of input data for GREET 1.0 — the first version of the GREET model — was derived from Delucchi's 1991 study.

2.2 National Renewable Energy Laboratory et al. 1991, 1992

The National Renewable Energy Laboratory (NREL), with assistance from Oak Ridge National Laboratory and Pacific Northwest National Laboratory, conducted an analysis that compared fuel-cycle emissions of biomass-based ethanol with those of reformulated gasoline (RFG) (NREL et al. 1991, 1992). The NREL study compared three fuels: RFG, E10 (mixture of 10% ethanol and 90% gasoline by volume), and E95 (mixture of 95% ethanol and 5% gasoline by volume). In its study, NREL assumed that E10 would be used by the year 2000 and E95 would be used by 2010. The researchers further assumed that ethanol would be produced from municipal solid waste (MSW) in 2000 and from biomass such as grasses and trees in 2010; production of ethanol from corn was excluded.

For the MSW-to-ethanol cycle in 2000, NREL selected one site: Chicago/Cook County. For the biomass-to-ethanol cycle in 2010, NREL selected five sites with distinctly different climatic, soil, and other natural parameters: Peoria, Illinois; Lincoln, Nebraska; Tifton, Georgia; Rochester, New York; and Portland, Oregon.

In estimating emissions for RFG production, NREL assumed two refineries with different levels of crude quality, refining capacity, and refinery emissions. The NREL researchers specified the compositions of RFG by using the general requirements contained in the 1990 Clean Air Act Amendments. In 1994, EPA adopted a final rule on RFG requirements that was based on potential emission reductions rather than on component compositions (EPA 1994). Because of this rule, actual RFG specifications in the future may vary among companies and will certainly differ from NREL's assumed specifications. For example, the NREL researchers assumed that methyl tertiary butyl ether (MTBE) was the sole oxygenate for RFG. However, in practice, ethanol, ethyl tertiary butyl ether (ETBE), or MTBE can be used as oxygenates in RFG.

The NREL study included estimates of solid waste, water pollutant, and air pollutant emissions. The air pollutants studied were VOCs, CO, NO_x, SO_x, CO_2, and particulate matter (PM). The researchers also calculated petroleum displacement from using E10 and E95.

NREL concluded that using MSW-based E10 in 2000 would cause very little change in fuel-cycle emissions when compared with using RFG because the major part of E10 is still gasoline. On the other hand, using biomass-based E95 in 2010 would reduce CO_2 emissions by 90% to 96% and reduce NO_x, SO_x, and PM emissions considerably. However, NREL found that use of E95 could increase VOC and CO emissions. On a per-mile basis, the study estimated that E10 would help displace 6% of fossil fuel use; E95 would displace 85%.

NREL researchers estimated significantly larger reductions in CO_2 emissions as a result of using ethanol than Delucchi did, primarily because the assumptions made by NREL favored ethanol. For example, NREL assumed high energy efficiencies and low emissions from ethanol fuel cycles, a high allocation of upstream ethanol cycle emissions to other by-products, a large electricity credit earned in ethanol plants, and favorable emission reductions for E10 and E95. NREL used EPA’s Mobile 4.1 model to estimate emissions from RFG-fueled baseline vehicles.

2.3 Bentley et al. 1992

Bentley et al. prepared a study for the Idaho National Engineering and Environmental Laboratory (INEEL) to estimate fuel-cycle CO_2 emissions from electric vehicles (EVs), fuel-cell vehicles (FCVs), and internal combustion engine vehicles (ICEVs) powered by different fuels (Bentley et al. 1992). The researchers included the following fuel cycles in their study: petroleum to gasoline, NG to methanol, NG to CNG, NG to hydrogen, corn to ethanol, and electricity generation from various fuels. While the study did not include an in-depth analysis of upstream fuel-cycle emissions (energy efficiencies and CO_2 emissions for upstream stages were derived primarily from other studies), it did present detailed projections of likely vehicle configurations, vehicle drivetrains, and component efficiencies.

Assuming improvements in energy efficiency for both upstream fuel production processes and vehicle technologies over time, Bentley et al. estimated CO_2 emissions in three target years: 2001, 2010, and 2020. The study included three vehicle types: commuter cars, family cars, and minivans. Vehicle component energy efficiencies were projected from those of 1992 GVs. Actual on-road fuel economy of advanced vehicles was projected by using SIMPLEV — a computer model developed at INEEL to simulate vehicle fuel economy. In using SIMPLEV, Bentley and his colleagues made assumptions regarding aerodynamics coefficients, rolling resistance, weight reduction, and battery technologies on the basis of optimistic projections of technology advances and the characteristics of some prototype vehicles. To estimate

EV fuel-cycle emissions, the researchers established the following three scenarios regarding the electricity generation mix:

- The national average generation mix (under which coal-fired power plants generate more than 50% of total electricity);
- Advanced NG combustion technology providing electricity for EVs; and
- The newest NG combustion technology with the highest possible conversion efficiency providing electricity for EVs.

Bentley et al. assumed that the conversion efficiency for advanced NG combustion technology would increase from 43% in 1992 to 50% in 2020 and the efficiency for the newest NG technology would increase from 43% in 1992 to 57% in 2020.

The conclusions drawn from the Bentley et al. study included the following:

- Gasoline and methanol vehicles produce about the same amount of fuel-cycle CO_2 emissions;
- Compressed natural gas vehicles (CNGVs), EVs, and vehicles powered by ethanol (all of which produce about the same amount of CO_2 emissions) generate fewer CO_2 emissions than do GVs;
- EVs produce fewer emissions than CNGVs if electricity is generated from NG; and
- FCVs fueled with NG-based hydrogen generate fewer CO_2 emissions than do CNGVs.

2.4 Brogan and Venkateswaran 1992

Brogan and Venkateswaran (1992) estimated fuel-cycle energy use and CO_2 emissions of various transportation technologies. Their study included EVs, hybrid electric vehicles (HEVs), FCVs, and ICEVs powered with different fuels, for a total of 19 propulsion-system/fuel options. Their analysis was conducted for typical mid-size passenger cars to be introduced in 2001. They used technology projections for 2001, except for some advanced technologies such as FCVs and HEVs, for which they used technology assumptions from prototype or concept designs.

Brogan and Venkateswaran calculated CO_2 emissions by assuming that all carbon contained in a fuel was oxidized into CO_2; carbon contained in CO and hydrocarbon (HC) emissions was not considered. Upstream emissions of HC, CO, NO_x, and SO_x were estimated only for the fuel production stage (e.g., petroleum refining and electricity generation); emissions from primary energy production and distribution, transportation, and storage of fuels were ignored. It appears that the authors used emission standards of ICEVs to represent actual on-road emissions.

In estimating EV energy use, Brogan and Venkateswaran made optimistic assumptions about battery technologies. They specified a series, range-extended HEV design and assumed methanol-fueled ceramic gas turbines for the HEV design. They arbitrarily assumed that for HEVs, 75% of the road power demand would be met with grid electricity and 25% with on-board gas turbine generators. Performance characteristics remained constant among the 19 vehicle options, except for the EVs, for which the driving range was assumed to be shorter than the range for the other vehicle types. Vehicle component efficiencies were derived directly from the projections made in the Bentley et al. study.

Brogan and Venkateswaran concluded that ICEVs fueled with gasoline, methanol, CNG, and ethanol had higher primary energy consumption rates than electric propulsion technologies (i.e., EVs, HEVs, and FCVs). Ethanol vehicles were shown to have the lowest CO_2 emission rate. The study revealed that on the basis of the average electric generation mix in the United States, EVs and HEVs generated fewer CO_2 emissions than gasoline ICEVs. The results for HC, CO, NO_x, and SO_x emissions were inconclusive, because the study did not estimate these emissions for the complete fuel cycle.

2.5 Ecotraffic, AB 1992

Researchers at Ecotraffic, AB, in Sweden estimated fuel-cycle emissions and primary energy consumption of various transportation fuels in Sweden (Ecotraffic, AB 1992). The Swedish study included the following fuel cycles: petroleum to gasoline, petroleum to diesel, petroleum to LPG, NG to CNG, NG to methanol, biomass to methanol, biomass to ethanol, rapeseed to vegetable oil, solar energy to hydrogen via electrolysis of water, NG to hydrogen, and electricity generation from various fuels. Fuel-cycle emissions of three criteria pollutants (HC, CO, and NO_x) and six GHGs (CO_2, CH_4, N_2O, NO_x, CO, and HC) were estimated for three vehicle types: cars, medium-duty trucks, and buses.

Ecotraffic estimated emissions of HC, CO, and NO_x from both upstream fuel production processes and vehicle operations by considering emission standards applicable to stationary sources and motor vehicles in Sweden. Emissions from the vehicles powered by diesel and gasoline were taken directly from laboratory emissions testing results. EV emissions were calculated for two electric generation mix scenarios. The first was the Swedish average electric generation mix, in which 50% of electricity is from hydropower, 45% is from nuclear energy, and the remaining 5% is from fossil fuels. Compared with the average generation mix in the United States, where more than 50% of electricity is generated from coal, the Swedish mix is very clean. In the second scenario, NG was the sole primary energy source for EV electricity generation.

Ecotraffic concluded that use of nonfossil fuels could result in a greater-than-50% reduction in GHG emissions when compared with use of petroleum-based fuels. Use of diesel and vegetable oils produced the greatest NO_x emissions. Because almost all electricity in Sweden is generated from hydropower and nuclear energy, use of EVs reduced emissions of criteria pollutants and GHGs dramatically. Because the study used only Swedish data on emissions and energy efficiencies, its conclusions may be applicable only to Sweden.

2.6 Wang and Santini 1993

Wang and Santini (1993) estimated fuel-cycle emissions of EVs and GVs in four U.S. cities (Chicago, Denver, Los Angeles, and New York) under different driving cycles. The study included emissions of HC, CO, NO_x, SO_x, and CO_2. An early version of EAGLES — a computer simulation model for vehicle fuel consumption developed at Argonne National Laboratory — was used to estimate GV fuel economy and EV electricity consumption under different driving cycles (Marr 1995). Considering city-specific electric generation mix and power plant emissions, Wang and Santini estimated power plant emissions attributable to EV use in each of the four cities. By using EPA's Mobile 5a model, they estimated in-use emissions of U.S. Tier 1 GVs. Petroleum refinery emissions attributable to GV use were included in the estimates.

Wang and Santini concluded that use of EVs reduced emissions of HC and CO by more than 98% in each of the four cities and under each of the six driving cycles studied. The amount of NO_x emitted from EVs depended on the stringency of NO_x control by power plants and on the type of power plants that provided electricity for EVs. In Chicago, Los Angeles, and New York, NO_x emissions were significantly reduced by using EVs, while in Denver, NO_x emissions were reduced only moderately. EV use reduced CO_2 emissions significantly under low-speed driving cycles; under high-speed driving cycles, Wang and Santini found that CO_2 emissions from EVs could increase because the EV energy benefit (relative to GVs) was reduced. In Denver, SO_x emissions increased when EVs were used because more than half of that city's electricity is generated from coal; emissions also increased in New York, where nearly half of electricity is generated from oil.

Although Wang and Santini assumed that sodium/sulfur (Na/S) batteries would be used for EVs, when estimating EV electricity consumption, they did not account for the loss of energy from the thermal management system that was necessary to maintain the high temperature required for Na/S batteries. They took into account emissions from power plants, refinery plants, and vehicle operations but did not consider emissions from other fuel-cycle stages.

2.7 Darrow 1994a, 1994b

Darrow conducted two separate studies: one for the Gas Research Institute (GRI) to analyze fuel-cycle emissions of alternative fuels (Darrow 1994a) and the other for Southern California Gas Company to compare fuel-cycle emissions from EVs and CNGVs (Darrow 1994b).

In his GRI study, Darrow included the following fuel cycles: petroleum to conventional gasoline, petroleum to RFG, petroleum to LPG, NG to CNG, NG to methanol, NG to LPG, corn to ethanol, and electricity generation from various fuels. Fuel-cycle emissions for five criteria pollutants (reactive organic gases [ROGs], NO_x, CO, SO_x, and PM_{10}) and three GHGs (CO_2, CH_4, and N_2O) were included in the study.

Darrow analyzed fuel-cycle emissions for the United States and California in two target years: 1994 and 2000. For the United States, he analyzed emission data from various areas of the country and aggregate U.S. data on emissions and energy efficiencies. For California, Darrow included emissions occurring only within the state. More than 50% of electricity in the United States is generated from coal, while natural gas, hydropower, and nuclear are the primary sources of electricity in California. Consequently, overall fuel-cycle emissions in California were significantly lower than those in the United States.

As the basis for his study, Darrow used a typical minivan powered by various fuels. For vehicular emissions, Darrow assumed federal Tier 1 standards for all ICEV types except CNGVs, for which the extremely low certification emission levels of the Chrysler CNG minivan were used. This assumption is problematic, because the difference between emission standards and emission certification levels can be as large as 50% — certification levels can be 50% lower than applicable standards. Furthermore, neither emission standards nor emission certification levels represent actual on-road emissions. Because of the deterioration of emission control systems over the life of the vehicle, lifetime average emission rates are much higher than emission standards and emission certification levels. It is also questionable to compare a very clean CNG van to other vehicles, which Darrow assumed would meet Tier 1 standards. The Chrysler CNG van is designed to achieve the lowest possible emissions. The vehicle's specialized catalyst formation, high catalyst loading, and engine modification are designed to reduce engine-out NO_x emissions. If the same intense emission control measures were applied to other vehicle types, their emissions would certainly be lower.

In the United States, Darrow showed that the fuel-cycle NO_x emissions generated from ICEVs powered by conventional gasoline, RFG, and LPG were similar. ICEVs powered by E85 (mixture of 85% ethanol and 15% gasoline by volume) and M85 (mixture of 85% methanol and 15% gasoline by volume) had relatively high NO_x emission rates. EVs had the most NO_x emissions, and CNGVs had the fewest.

ICEVs powered by conventional gasoline, RFG, LPG, E85, and M85 had similar ROG and CO emission rates. CNGVs had significantly fewer emissions, and EVs had the fewest emissions. In California, EVs were shown to have fewer emissions of NO_x, ROG, and CO. CNGVs produced the fewest NO_x emissions.

The extremely low emission levels from CNGVs estimated by Darrow for both the United States and California were caused by his use of the extremely low certification emission levels of the Chrysler CNG minivan for CNGVs. In fact, Darrow showed that, when Tier 1 standards were applied to CNGVs as well as to other vehicle types, CNGVs usually demonstrated few emission reduction benefits; the emission rates from CNGVs were about the same as those from LPGVs.

Darrow presented GHG emissions from various transportation fuels but did not provide the details for his GHG emission calculations. He showed that EVs and vehicles powered by E85 and M85 had high CO_2-equivalent emissions; gasoline and CNG ICEVs produced GHG emissions at an equal rate, and LPGVs generated the fewest GHG emissions.

In his study for Southern California Gas Company (Darrow 1994b), Darrow compared fuel-cycle emissions from CNGVs and EVs. By using the data and assumptions that he applied in his study for GRI, he concluded that in Southern California, while in-basin emission rates from EVs were generally lower than those for CNGVs, all-location emission rates of NO_x from EVs were slightly higher than those from CNGVs. However, EVs always generated fewer all-location ROG and CO emissions than did CNGVs.

2.8 Acurex 1996

Acurex Environmental Corporation conducted a study for the California Air Resources Board (CARB) to estimate the fuel-cycle emissions of RFG, clean diesel, and alternative transportation fuels (Acurex 1995). The Acurex study included the following fuel cycles: petroleum to conventional gasoline, petroleum to RFG, petroleum to clean diesel, NG to LPG, NG to methanol, NG to CNG, NG to LNG, coal to methanol, biomass (including corn, woody and herbaceous biomass) to methanol, biomass to ethanol, electricity generation from various fuels, and hydrogen from electricity via electrolysis of water. The study examined three criteria pollutants (NO_x, NMOG, CO) and two GHGs (CO_2 and CH_4). NMOG emissions from different fuel production processes and from vehicles using different alternative fuels were adjusted to account for their ozone-forming potentials.

Acurex established a framework for estimating fuel-cycle emissions in California between 1990 and 2010. Emission regulations applicable to this timeframe in California were taken into account. In particular, Acurex considered the reductions in stationary source emissions brought about by the adoption of emission regulations by the South Coast Air Quality Management District (SCAQMD). Given the uncertainties involved in emission controls and fuel economy improvements from the present to 2010, Acurex established three scenarios in 2010 to reflect varying degrees of stationary emission controls and vehicle fuel economy.

Acurex produced an HC speciation profile for NMOG emissions from each fuel-cycle stage and for each vehicle type to estimate ozone reactivity-adjusted NMOG emissions. The speciated NMOG emissions were then multiplied by the maximum incremental ozone reactivity factors developed by CARB to calculate ozone reactivity-adjusted NMOG emissions. Only NMOG emissions occurring within California were taken into account in fuel-cycle NMOG emission calculations.

In calculating EV emissions, Acurex used four sets of electric generation mix: a marginal generation mix for EVs in California, an average generation mix in the South Coast Air Basin, a U.S. average generation mix, and a worldwide average generation mix. The worldwide average generation mix may have little meaning because EVs will not be introduced worldwide.

The Acurex study revealed the following about per-mile emissions from vehicles in 2010. Vehicles powered by LNG, CNG, LPG, and hydrogen would generate the fewest CO_2 emissions; followed by vehicles powered by M100 (100% methanol by volume), M85, E85, and diesel; then by gasoline-powered vehicles. EVs had the highest CO_2 emissions. In fact, the CO_2 emission rates of EVs were more than twice as high as those of GVs.

For NO_x emissions occurring within the South Coast Air Basin, vehicles powered by CNG, hydrogen, LPG, electricity, and diesel generated the fewest emissions; followed by vehicles powered by E85, M85, and RFG; then by vehicles powered by M100. Vehicles powered by LNG produced the highest in-basin NO_x emission rates (emission rates from LNG-powered vehicles were five times as high as those from GVs).

Vehicles powered by hydrogen, LNG, electricity, CNG, M100, and diesel generated the lowest rate of ozone reactivity-adjusted NMOG emissions; followed by vehicles powered by E85 and M85; then by GVs. LPG vehicles generated the highest rates of ozone-adjusted NMOG emissions.

In its study, Acurex thoroughly characterized emissions of various fuel production processes in California, especially in the South Coast Air Basin. Acurex collected extensive emissions data, and its established fuel-cycle framework will serve as a useful tool to estimate fuel-cycle emissions in California. However, the study did not include PM_{10} and SO_x emissions. PM_{10} and other fine particulates have increasingly become a concern since studies have found that fine particulates may have already caused significant damage to human health. Researchers' ability to apply the Acurex framework for California to other regions in the United States remains unclear.

2.9 Delucchi 1997

In 1997, Delucchi issued a report documenting revisions made to his 1991 study (Delucchi 1997). With newly available data, Delucchi updated many of his parametric assumptions and used new methodologies to account for energy use and emissions associated with fuel-cycle stages.

Comparison of the GREET model and the Delucchi model reveals that, in many cases, the GREET model takes its parametric assumptions from model users, while the Delucchi model calculates parametric values that are determined by certain assumptions. For example, the value used by GREET to calculate relative differences in vehicle fuel economy between AFVs and GVs is determined outside of GREET by comparing testing data from AFVs and GVs. The Delucchi model calculates a relative change in fuel economy for AFVs by taking into account potential differences in engine efficiency, vehicle weight, and so on.

2.10 Argonne National Laboratory et al. 1998

Between 1993 and 1996, DOE commissioned a multi-national laboratory study to assess energy and emission impacts of using EVs relative to GVs (Argonne National Laboratory et al. 1998a,b). The study, called the Electric Vehicle Total Energy Cycle Analysis (EVTECA), assessed EV impacts in four metropolitan areas (Chicago, Houston, Los Angeles, and Washington, D.C.) where air quality improvements were needed and where patterns of vehicle use, electric generation, and baseline gasoline quality varied. The study characterized EVs equipped with four battery types typical of battery technologies being studied around 1994: advanced lead-acid, nickel-cadmium, nickel-metal hydride, and sodium-sulfur. The study assumed that EV technologies would penetrate passenger car and van markets. GV fuel economy and EV electricity consumption rates between 1998 and 2010 were simulated by means of an Argonne vehicle model. The estimated per-mile EV electricity use rate, together with total daily travel and recharge requirements and total EV market penetration, was used to determine the total daily electricity demand by EVs in each of the four areas. High and low EV market penetration scenarios were assumed for each area.

On the basis of the predicted electricity demand by EVs, NREL conducted electric utility simulations to determine marginal electric power plants for providing electricity for EVs and energy use and emissions in the electric utility sector induced by use of EVs. Additional electric generation capacity, which was required to meet EV electricity demand, was assumed to be provided by coal- and/or gas-fired advanced power plants. The comprehensive utility simulation showed that energy use and emissions associated with EVs varied from region to region and within regions depending on the assumptions that researchers made regarding the constraints associated with EV recharging, the type of electric generation capacity to be added, and the season of the year.

In addition to fuel-cycle energy use and emissions for both gasoline and electricity, the EVTECA study included energy use and emissions associated with the vehicle cycle. That is, researchers estimated energy use and emissions of material recovery, material fabrication, vehicle assembly, vehicle disposal/recycling, battery production, and battery disposal/recycling. The vehicle cycle analysis revealed that the manufacturing process for EVs would generate more criteria pollutant emissions than the manufacture of conventional vehicles, mainly because of EV battery production and recycling.

The EVTECA generated many results for the various combinations of cases. In general, the following conclusions were made on the basis of the study results:

- CVs use 15–40% more energy than EVs on a per-mile basis.
- Use of EVs reduced emissions of VOCs and CO by over 90% and emissions of CO_2 by 25–65%.
- All cases examined led to reductions in NO_x emissions, but the magnitude of reductions varied greatly between regions and depended primarily on the type of EV charging process assumed.
- EVs increased emissions of total suspended particulates and SO_x.
- Lead emissions increased significantly when lead-acid battery-equipped EVs were used.

2.11 Sheehan et al. 1998

In 1998, NREL completed a study for the U.S. Department of Agriculture and DOE to evaluate fuel-cycle energy and emission impacts of using biodiesel (BD) in place of petroleum diesel in urban buses (Sheehan et al. 1998). Although BD can be produced from several feedstocks, the study evaluated the production of BD from soybeans, the major pathway in the United States. In the study, the petroleum diesel fuel cycle included stages from petroleum recovery to diesel combustion on buses, and the BD cycle included stages from soybean farming to BD combustion on board diesel buses. The study included fossil energy use, petroleum use,

CO_2 emissions, and emissions of five criteria pollutants (NMHC, CO, NO_x, PM_{10}, and SO_x). The study also estimated, though less thoroughly, the amount of waste water and the amount of solid waste generated during production of BD.

The study included significant details regarding production locations for both feedstocks and fuel products and energy and emissions for each stage. A life-cycle model developed by Ecobalance, Inc. (a consulting company in Virginia) was used for the study, which provided a wealth of detailed information on energy use and emissions for each stage involved in the two fuel cycles.

The study resulted in the following conclusions. Use of pure BD can reduce petroleum use by over 95%, fossil energy use by about 70%, and CO_2 emissions by 78%. Emissions of PM, CO, and SO_x are reduced by 32%, 35%, and 8%, respectively. However, use of BD increases NO_x emissions by 13% and HC emissions by 35%. The increase in HC emissions is mainly caused by high levels of HC emissions during BD production.

2.12 Summary

Of the 11 studies discussed, those conducted by Delucchi and Acurex are the most comprehensive in terms of fuels and technologies. Through his study, Delucchi established a spreadsheet-based model to calculate GHG emissions. Acurex established a framework to calculate fuel-cycle emissions. But because the framework was designed for California only, it is not clear whether it can be used to estimate emissions for other U.S. regions. For a given fuel, the 1998 Argonne study was the most detailed on electric vehicles. The 1991 NREL study (NREL et al. 1991) was the most thorough study on cellulosic ethanol. The 1998 NREL study (Sheehan et al. 1998) was the most extensive study on BD.

Section 3
Modeling Approach

3.1 Fuel Cycles and Their Stages

The use of motor vehicles involves two different energy cycles: production and use of motor fuels (fuel cycle) and production and use of motor vehicles (vehicle cycle). The *fuel cycle* for a given transportation fuel includes the following processes: primary energy (i.e., energy feedstock) production, transportation, and storage (T&S); fuel (i.e., energy source) production, transportation, storage, and distribution (T&S&D); and vehicle operations that involve fuel combustion or other chemical conversions (Figure 3.1). The *vehicle cycle* includes material recovery and fabrication, vehicle production, vehicle operation, and vehicle disposal/recycling. (Note that vehicle operation is included in both the fuel cycle and the vehicle cycle.) The processes that precede vehicle operations are often referred to as upstream activities; actual vehicle operations are referred to as downstream activities.

To evaluate various motor vehicle technologies, both cycles should be considered, because in many cases, use of an alternative transportation fuel or an advanced vehicle technology involves changes in both upstream fuel production activities and in production of materials and vehicles. In energy and emission analyses for consumer goods, researchers often refer to studies of the “cradle to grave” cycle of a product as *life-cycle analysis* (LCA). A so-called *total energy-cycle analysis* (TECA) for transportation technologies includes both the fuel and the vehicle cycles. When TECA results for ICEV-based technologies are separated into three groups — fuel-cycle upstream activities, vehicle production and disposal, and vehicle operations — energy use and emissions from vehicle operations are the largest, those from upstream activities are second, and those from vehicle production and disposal are the smallest. Figure 3.1 presents a flow chart for a total energy-cycle analysis.

The GREET model has been developed to calculate per-mile energy use and emission rates of various combinations of vehicle technologies and fuels for both fuel cycles and total energy cycles. Since the development of GREET 1.0 (which was a fuel-cycle model only), the model has evolved to include three components. The first — the Series 1 component (GREET 1.0, 1.1, 1.2, 1.3, and so on) — calculates fuel-cycle energy use and emissions of light-duty vehicles (passenger cars, vans, and light-duty trucks [LDTs]). This series is the continuation of GREET 1.0. The second — the Series 2 component — calculates vehicle-cycle energy use and emissions of light-duty vehicles. The Series 2 component was developed through Argonne’s effort on total energy-cycle analysis for HEVs. During calculations, the Series 2 model draws data from the Series 1 model to estimate vehicle-cycle energy use and emissions. Energy and emission results of fuel cycle (calculated in Series 1) and vehicle cycle (calculated in Series 2) analyses are combined in Series 2. So, the Series 1 model presents fuel-cycle results only, and the Series 2 model presents both fuel-cycle and total energy-cycle results. Development and use of the Series 2 GREET model will be documented elsewhere.

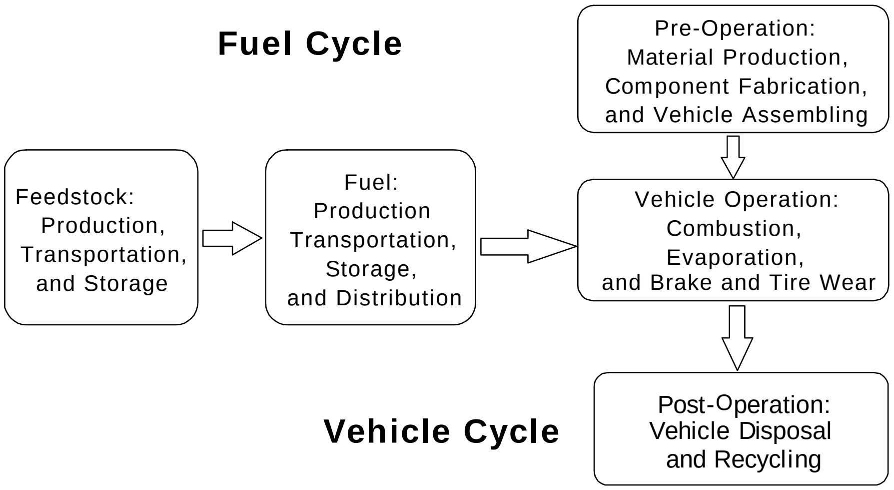

Figure 3.1 Flowchart of a Total Energy-Cycle Analysis

The third component of the GREET model — Series 3 — was developed to estimate fuel-cycle energy use and emissions of heavy-duty vehicles (class 2b to class 8 trucks). The Series 3 model draws data for upstream fuel production activities from the Series 1 model. Development and use of the Series 3 GREET model will be documented elsewhere.

This report documents development and use of the most recent version of the Series 1 model: GREET 1.5. Since 1996, some interim versions (i.e., GREET 1.1, GREET 1.2, GREET 1.3, and GREET 1.4) were developed. Those versions involved some changes in parametric assumptions regarding fuel production and included additional fuels and vehicle technologies. They were used to generate interim results by Argonne and other institutions to evaluate various transportation technologies. No formal documentation for those versions was published. GREET 1.5 includes more than 30 fuel cycles (Table 3.1), involving 13 types of fuel feedstocks (petroleum, NG, flared gas, coal, soybeans, uranium, corn, woody biomass, herbaceous biomass, landfill gases, hydropower, solar energy, and wind) and 14 fuels (conventional gasoline [CG], RFG, conventional diesel [CD], reformulated diesel [RFD], LPG, CNG, LNG, methanol, dimethyl ether [DME], ethanol, hydrogen, Fischer-Tropsch diesel [FTD], biodiesel, and electricity). Because virtually no emissions are associated with electricity generated from hydropower, solar energy, and wind, these cycles are treated together as zero-emission cycles in GREET. These fuel cycles are included in GREET 1.5 essentially because researchers are interested in them and because data regarding fuel production are available. Other cycles may be added to GREET as additional emission and energy use data become available. Detailed technology descriptions and assumptions for these cycles are presented in Section 4.

Table 3.1 Fuel Cycles Included in GREET 1.5

Primary Energy Source	Fuel
Petroleum	Conventional gasoline Reformulated gasoline Conventional diesel Reformulated diesel Liquefied petroleum gas Electricity via residual oil
Natural gas	Compressed natural gas Liquefied natural gas Liquefied petroleum gas Methanol Dimethyl ether Gaseous hydrogen/ central plants Gaseous hydrogen/ refueling stations Liquid hydrogen Fischer-Tropsch diesel Electricity
Flared gas	Methanol Dimethyl ether Fischer-Tropsch diesel
Coal Uranium Hydropower, solar energy, and wind	Electricity
Corn: dry milling Corn: wet milling Woody biomass Herbaceous biomass	Ethanol
Solar energy (via water electrolysis)	Gaseous hydrogen Liquid hydrogen
Soybeans	Biodiesel
Landfill gases	Methanol

3.2 Vehicle Types

As stated above, the Series 1 GREET model estimates fuel-cycle energy use and emissions of light-duty vehicles (i.e., passenger cars and LDTs). Heavy-duty trucks (HDTs) are included in the Series 3 GREET model. Table 3.2 lists vehicle types included in the Series 1 and 3 models. Vehicle types are divided between the two models according to the way in which emission standards are set. For passenger cars, Class 1 trucks (commonly called light-duty trucks 1 [LDT1s]), and Class 2a trucks (commonly called light-duty trucks 2 [LDT2s]), emission standards are set by the EPA on a per-mile basis. Vehicle emissions for these vehicle types are measured on *vehicle chassis* dynamometers. For truck Classes 2b–8b and buses (called HDTs), emission standards are set for engines on a per-brake-horsepower-hour basis. Emissions from *engines*, not from vehicles, are measured on *engine* dynamometers. Emissions from HDTs need to be converted into per-mile emissions for use in the models. This conversion step, which is subject to some uncertainties, makes emission calculations for HDTs different than those for passenger cars and LDTs.

For passenger cars and LDTs, GREET 1.5 includes the following technologies: EVs; HEVs; FCVs fueled with hydrogen, methanol, gasoline, ethanol, or CNG; spark-ignition ICEVs fueled with CG, RFG, CNG, LNG, LPG, or ethanol; and compression-ignition ICEVs fueled with CD, RFD, DME, FTD, or biodiesel. Details on the selection of these fuel/vehicle combinations are presented in Section 4.

Table 3.2 Vehicle Types Included in Series 1 and 3 GREET Models

Series 1 GREET Model		Series 3 GREET Model	
Vehicle Type	GVWR[a] (lb)	Vehicle Type	GVWR[a] (lb)
Passenger cars	0 – 6,000	Class 2b – 4 trucks	8,501 – 16,000
Class 1 trucks (LDT1)	0 – 6,000	Class 5 – 6 trucks	16,001 – 26,000
Class 2a trucks (LDT2)	6,001 – 8,500	Class 7 trucks	26,001 – 33,000
		Class 8a trucks	33,001 – 60,000
		Class 8b trucks	> 60,000
		School buses	21,000 – 31,000
		Transit and commercial buses	26,001 – 60,000

[a] Gross vehicle weight rating.

3.3 Calculation of Energy Use and Emissions of Upstream Stages

3.3.1 Calculation of Energy Use for an Upstream Stage

To estimate fuel-cycle energy use and emissions, GREET first estimates energy use (in British thermal units [Btu]) and emissions (in grams) per million Btu [g/10^6 Btu) of fuel throughput for a given upstream stage. The model then combines the energy use and emissions from all upstream stages for a fuel cycle to estimate total upstream fuel-cycle energy use and emissions. The aggregation takes into account, among other factors, loss of a fuel during the fuel cycle (see detailed discussion in Section 3.3.4). Because fuel-cycle fossil fuel and petroleum consumption, as well as total energy consumption, are of interest, GREET is designed to calculate both of these values as well as fuel-cycle total energy consumption, all at the primary energy level. Energy consumption and emissions of the following fossil fuels are calculated in GREET: petroleum, NG, and coal. Total energy includes fossil energy and renewable energy such as solar energy, wind, and geothermal energy. Therefore, the model can estimate the amount of fossil fuel and petroleum displaced as a result of using alternative transportation fuels and advanced vehicle technologies instead of conventional vehicles fueled with gasoline.

For a given upstream stage, energy input per unit of energy product output is calculated by using the energy efficiency of the stage. By definition, energy efficiency is the energy output divided by the energy input (including energy in both process fuels and energy feedstock). Thus, total energy input is:

$$Energy_{in} = 1/efficiency, \tag{3.1}$$

where

Energy_{in} = Energy input of a given stage (say, in Btu per Btu of energy product output from the stage), and

Efficiency = Energy efficiency for the given stage (defined as [energy output]/[energy input] for the stage).

The energy efficiencies of each upstream stage for various fuel cycles are presented in Section 4.

Equation 3.1 calculates total energy input to a process. The total energy input comprises energy feedstock and process fuels. In most cases, energy feedstock includes both a feed for production of a fuel and a process fuel used during production. To calculate emissions, especially emissions of criteria pollutants, the total feedstock input needs to be separated into feed and fuel. Converting feed to a given fuel (which, in most cases, is a chemical process) may or may not produce emissions. Combustion of a feedstock as a fuel certainly produces emissions. The combustion emissions can be estimated by using the amount of fuel burned and the combustion emission factors.

To separate energy feedstock input between feed and fuel, researchers must consider three cases. In the first case, all the energy feedstock input is burned in producing a fuel. An example is electricity generation. In the second case, some (usually a majority) of the energy feedstock input is used as feed in a conversion process to produce a fuel; the remainder, together with any other process fuels necessary for the conversion process, is burned to provide heat or steam for the process. Examples include chemical processes such as production of methanol, hydrogen, DME, and FTD from natural gas. In this case, the total natural gas input needs to be broken down into natural gas used as feed and natural gas used as fuel. Only the natural gas used as fuel is included in combustion emission calculations. In the third case, no chemical processes are involved in production (or transformation) of a fuel. Of the total energy feedstock input, a unit of energy in fuel product output requires a unit of energy in feedstock input. The difference between the energy in the feedstock input and the energy in the energy product is the amount of feed used as the process fuel. Examples include CNG and LNG production. For this case, the following equation is used to estimate the amount of process fuel required:

$$Process\ Fuels = 1/efficiency - 1, \qquad [3.2]$$

where

Process fuels = The amount of process fuels required during a given stage to generate one unit of energy for production (say, in Btu per Btu of energy output from the stage), and

Efficiency = Energy efficiency for a given stage (defined as [energy output]/[energy input] for the stage).

The calculated energy consumption of all process fuels for a particular stage is then allocated to the different process fuels burned during the stage. For example, if 10^3 Btu of process fuels is burned to deliver 10^6 Btu of fuel throughput from an upstream stage, GREET allocates the 10^3 Btu of process fuels into individual process fuels such as diesel, residual oil, and electricity. GREET includes the following process fuels: NG, residual oil, diesel, gasoline, crude oil, LPG, coal, electricity, and biomass. Allocating the percentages of total energy burned to different process fuels for a given stage is necessary to allow researchers to calculate emissions from the stage; the amount of emissions attributable to fuel combustion depends very much on the type of fuel burned. The allocation process is also necessary for calculating fossil fuel use and petroleum use for each stage.

The shares of process fuels in total fuel use for fuel-cycle stages are different for different fuel cycles and different stages. For existing fuels industries (such as oil, NG, coal, and electric industries), process fuel shares are usually estimated on the basis of historical statistical data on fuel use by fuel type. In these cases, GREET relies primarily on results from Delucchi (1997). For new industries that produce new fuels (such as DME, FTD, and cellulosic ethanol), process fuel shares are assumed in GREET by considering process fuel shares for similar industries and the availability of process fuels.

Although energy efficiencies are used to calculate energy use for most upstream stages according to Equations 3.1 and 3.2, the actual amounts of process fuel and feedstock inputs and product fuel outputs are used to calculate energy use for some stages. For example, in estimating energy use and emissions for production of ethanol from corn, the amounts of corn input (in bushels) and process fuels (in Btu) per gallon of ethanol produced are estimated and entered in GREET. Use of physical units instead of energy use in these cases makes GREET input assumptions more transparent. This applies to ethanol production from corn and biomass, biodiesel production from soybean, and production and transportation of fertilizers, insecticide, and herbicide. Details of inputs and outputs for individual stages are presented in Section 4.

3.3.2 Calculation of Emissions for an Upstream Stage

Emissions of VOCs, CO, NO_x, PM_{10}, SO_x, CH_4, N_2O, and CO_2 for a particular stage are calculated in g/10^6 Btu of fuel throughput from the stage. Emissions occurring during a stage include those resulting from the combustion of process fuels and from noncombustion processes such as chemical reactions and fuel leakage and evaporation. Emissions resulting from chemical reactions, fuel leakage, and fuel evaporation are fuel- and stage-specific; they are presented in Section 4, as needed. Emissions from combustion of process fuels for a particular stage are calculated by using the following formula:

$$EM_{cm,i} = (\sum_j \sum_k EF_{i,j,k} \times EC_{j,k}) \div 1{,}000{,}000, \qquad [3.3]$$

where

$EM_{cm,i}$ = Combustion emissions of pollutant i in g/10^6 Btu of fuel throughput,
$EF_{i,j,k}$ = Emission factor of pollutant i for process fuel j with combustion technology k (g/10^6 Btu of fuel burned), and
$EC_{j,k}$ = Consumption of process fuel j with combustion technology k (Btu/10^6 Btu of fuel throughput).

$EC_{j,k}$ for a given stage is, in turn, calculated by using the following formula:

$$EC_{j,k} = EC \times Share_{fuelj} \times Share_{techk,j} \ , \qquad [3.4]$$

where

EC = Total energy consumption for the given stage (in Btu/10^6 Btu of fuel throughput, calculated with Equation 3.1 or 3.2),
$Share_{fuelj}$ = Share of process fuel j out of all process fuels consumed during the stage ($\sum_j fuel_j = 1$, see Section 4 for the shares), and
$Share_{techk,j}$ = Share of combustion technology k out of all combustion technologies for fuel j ($\sum_k tech_{k,j} = 1$).

Combustion technology shares ($Share_{techk,j}$) for a given process fuel are influenced by technology performance, technology costs, and emission regulations for stationary sources. Over time, because of increasingly strict emissions regulations, clean-burning technologies will likely be introduced to replace old combustion technologies. In GREET, default technology shares are assumed for each upstream stage. In most cases, for a given combustion technology, GREET has two sets of emission factors: current and future. Current technology factors are used for those emission control technologies that were in place in the early 1990s when the 1990 Clean Air Act Amendment took effect. Future technology emission factors are used for additional emission control technologies employed to reduce emissions further. These technologies are introduced gradually in GREET over time to replace the current technologies. The default shares are based on use of combustion technologies in different fuel industries now and in the near future. To precisely simulate energy use and emissions over a period of time, users of the GREET model need to assess potential use of clean-burning technologies and change the assumed default technology shares accordingly.

Emission factors ($EF_{i,j,k}$) for VOC, CO, NO_x, PM_{10}, CH_4, and N_2O for different combustion technologies fueled by different process fuels are primarily derived from the fifth edition of EPA’s AP-42 document (EPA 1995). GREET has a sheet called *EF* that contains emission factors for 41 combinations of combustion technologies and fuels. Appendix A (in Volume 2) of this report presents these emission factors.

In the GREET model, SO_x emission factors for combustion technologies fueled with all fuels except coal, crude oil, and residual oil are calculated by assuming that all sulfur contained in these process fuels is converted into sulfur dioxide (SO_2). The following formula is used to calculate the SO_x emissions of combustion technologies:

$$SO_{x,j} = Density_j \div LHV_j \times 1{,}000{,}000 \times S\_ratio_j \times 64 \div 32 , \qquad [3.5]$$

where

$SO_{x,j}$ = SO_x (primarily SO_2) emission factor for combustion of process fuel j (in g/10^6 Btu of fuel j burned);

Density_j = Density of process fuel j (in grams per gallon [g/gal] for liquid fuels, grams per standard cubic foot [g/scf] for gaseous fuels such as NG and gaseous hydrogen, or grams per ton [g/ton] for solid fuels such as coal and biomass);
LHV_j = Low heating value of process fuel j (in Btu/gal for liquid fuels, Btu/scf for gaseous fuels, or Btu/ton for solid fuels);
S_ratio_j = Sulfur ratio by weight for process fuel j;
64 = Molecular weight of SO_2; and
32 = Molecular weight of elemental sulfur.

As the formula implies, SO_x emission factors for most fuels are determined by the sulfur content of the fuels and not by combustion technologies. However, uncontrolled SO_x emission factors associated with combustion of residual oil, crude oil, and coal are very high and exceed emission standards. Desulfurization measures have been in place for combustion technologies fueled with these three fuels to reduce SO_x emissions to acceptable levels. For these cases, SO_x emission factors for various combustion technologies are derived from the fifth edition of EPA's AP-42 document (EPA 1995).

There are some exceptions to the method of calculating SO_x emissions described above. Some chemical conversions of feedstocks to fuels or energy require catalysts; these conversions include production of methanol, DME, hydrogen, and FTD from natural gas in plants and production of hydrogen from gasoline, methanol, ethanol, and natural gas on board a fuel-cell vehicle with fuel processors. Sulfur contained in a feedstock can poison catalysts and must be removed from the feedstock before it enters the fuel production units. Desulfurization of feedstocks usually produces solid wastes that contain immobilized sulfur. In these cases, the sulfur contained in the feedstocks used as feed and fuel becomes solid waste, and is not released as emissions. No SO_x air emissions are assigned for these cases.

In GREET, combustion CO_2 emission factors in g/10^6 Btu of fuel throughput are calculated by using a carbon balance approach. Through the approach, the carbon contained in a process fuel burned minus the carbon contained in combustion emissions of VOCs, CO, and CH_4 is assumed to convert to CO_2. The following formula is used to calculate CO_2 emissions:

$$\begin{aligned} CO_{2,j,k} = {} & \Big[Density_j \div LHV_j \times 1{,}000{,}000 \times C\_ratio_j - \big(VOC_{j,k} \times \\ & 0.85 + CO_{j,k} \times 0.43 + CH_{4,j,k} \times 0.75 \big) \Big] \times 44 \div 12 , \end{aligned} \qquad [3.6]$$

where

$CO_{2,j,k}$ = Combustion CO_2 emission factor for combustion technology k burning process fuel j (in g/10^6 Btu of fuel j burned);
Density_j = Density of process fuel j (in g/gal for liquid fuels, g/scf for gaseous fuels, or g/ton for solid fuels);
LHV_j = Low heating value of process fuel j (in Btu/gal for liquid fuels, Btu/scf for gaseous, or Btu/ton for solid fuels);

C_ratio_j = Carbon ratio by weight for process fuel j;
$VOC_{j,k}$ = VOC emission factor for combustion technology k burning process fuel j (in g/10^6 Btu of fuel j burned);
0.85 = Estimated average carbon ratio by weight for VOC combustion emissions;
$CO_{j,k}$ = CO emission factor for combustion technology k burning process fuel j (in g/10^6 Btu of fuel j burned);
0.43 = Carbon ratio by weight for CO;
$CH_{4,j,k}$ = CH_4 emission factor for combustion technology k burning process fuel j (in g/10^6 Btu of fuel j burned);
0.75 = Carbon ratio by weight for CH_4;
44 = Molecular weight of CO_2; and
12 = Molecular weight of elemental carbon.

The above formula shows the calculation method for combustion CO_2 emissions by which carbon contained in VOC, CO, and CH_4 is subtracted. On the other hand, VOCs and CO reside in the atmosphere for less than 10 days before decay into CO_2. In GREET 1.5, the indirect CO_2 emissions from VOCs and CO decay in the atmosphere are considered.

Calculations involved in Equations 3.5 and 3.6 require fuel specifications such as low heating value, fuel density, weight ratio of carbon, and weight ratio of sulfur. Fuel specifications for various fuels are presented in Table 3.3. A sheet containing the information (called *Fuel_Specs*) is included in the GREET model.

Throughout this report and in default calculations performed by GREET, low heating values (LHVs) are used for all the fuels involved. Some other studies use high heating values (HHVs). The difference between the LHV and the HHV for a fuel is determined by whether energy contained in the water vapor from fuel combustion is taken into account. For stationary combustion processes, some, but not all, of the energy contained in combustion vapor can be recovered in steam and used. For motor vehicles, energy contained in water vapor cannot be practically recovered. Thus, it is more appropriate to use LHV for vehicle applications. However, because heating values are used primarily as conversion factors to derive final results, either LHV or HHV can be used as long as whichever is chosen to be used consistently throughout a study. Inconsistencies occur when data from different studies that use both LHV and HHV are used. The GREET model is designed so the researcher can choose to use either LHV or HHV.

For noncombustion emissions, GREET takes into account the following emission sources. (Details on calculation of noncombustion emissions are presented in Section 4, as needed.)

- For liquid fuels, VOC evaporative emissions and emissions from fuel spillage during feedstock T&S and fuel T&S&D;

- For petroleum-based fuels, emissions from flaring and venting of associated gas in oil fields and refining-process-related emissions in petroleum refineries;

Table 3.3 Fuel Specifications

Fuel	LHV	HHV	Density	C ratio (% by wt)	S ratio (ppm by wt)
Liquid Fuels	(Btu/gal)	(Btu/gal)	(g/gal)		
Crude oil	130,000	138,100	3,200	85.0	16,000
Conventional gasoline	115,500	125,000	2,791	85.5	200
Federal reform. gasoline	112,300	121,500	2,795	82.9	30
Calif. Reform. gasoline	113,000	122,200	2,794	83.5	30
Conventional diesel	128,500	138,700	3,240	87.0	250
Reformulated diesel	128,000	138,000	3,240	87.0	050
Residual oil	140,000	149,500	3,630	87.0	5,000
Methanol	57,000	65,000	2,996	37.5	0
Ethanol	76,000	84,500	2,996	52.2	0
Liquefied petroleum gas	84,000	91,300	2,000	82.0	0
Liquefied natural gas	72,900	80,900	1,589	74.0	0
Dimethyl ether	68,180	NA[a]	2,502	52.2	0
Methyl ester (biodiesel)	117,090	128,520	3,346	78.0	0
Fischer-Tropsch diesel	118,800	128,500	2,915	86.0	0
Liquid hydrogen	30,100	35,700	263	0.0	0
NG liquids	81,460	90,500	NA	NA	NA
Still gas	128,590	142,860	NA	NA	NA
Gaseous Fuels	(Btu/scf)	(Btu/scf)	(g/scf)		
Natural gas	928	1,031	20.5	74.0	7
Gaseous hydrogen	274	324	2.4	0.0	0
Solid Fuels	(Btu/ton)	(Btu/ton)			
Coal	18,495,000	20,550,000	NN[b]	60.0	11,100
Coking coal	20,532,600	22,814,000	NN	NA	11,800
Woody biomass	17,000,000	NA	NN	NA	NA
Herbaceous biomass	15,600,000	NA	NN	NA	NA

[a] NA = not available.

[b] NN = not needed.

- For NG-based fuels, CH_4 emissions caused by gas leakage during NG transmission, noncombustion emissions during NG processing, and CO_2 emissions or absorption during production processes from NG to hydrogen, methanol, DME, or FTD;

- For ethanol and biodiesel, NO_x and N_2O emissions from nitrification and denitrification of nitrogen fertilizer applied during farming of corn, soybeans, and biomass; and

- For the coal-to-electricity cycle, CH_4 emissions during coal mining and process-related emissions during coal processing.

3.3.3 Consideration of Energy Use and Emissions of Upstream Stages for a Fuel Cycle

For a given fuel cycle, vehicle operation is considered a downstream stage; the stages before vehicle operation (production and transportation of feedstock and production and distribution of product fuels) are upstream stages. Upstream energy use and emissions are generated during combustion of process fuels and during production and distribution of the fuel to the consumption site. Energy use and emissions of a given upstream stage are calculated by using the following formula:

$$EM_i = (\sum_j (EM_{cm,i,j} + EF_{up,i,j}) \times EC_j) \div 1{,}000{,}000 \qquad [3.7]$$

where

EM_i = Emissions of pollutant i in g/10^6 Btu of fuel throughput from a given stage;
$EM_{cm,i,j}$ = Combustion emissions of pollutant i in g/10^6 Btu of process fuel j burned (calculated from Equation 3.3);
$EF_{up,i,j}$ = Upstream emissions of pollutant i in g/10^6 Btu of process fuel j to produce and distribute the process fuel to the stage (considered within GREET through circular calculation programming); and
EC_j = Energy consumption of fuel j during the stage (calculated from Equation 3.1 or 3.2).

As Equation 3.7 shows, the introduction of $EF_{up,i,j}$ to the formula causes circular calculations in GREET 1.5. That is, each upstream stage requires use of process fuels for which production could involve the very stage under evaluation. As Figure 3.2 shows, the circular calculations help fully account for upstream energy use and emissions. The figure uses the petroleum-to-diesel cycle as an example. Petroleum recovery, as one stage of the cycle, requires use of diesel fuel, together with other process fuels (not shown in the figure). Production of diesel fuel requires petroleum recovery together with other stages (petroleum T&S, petroleum refining, and diesel T&S&D to oilfields). As the figure shows, other stages require the use of diesel fuel, and together there are four close-loop calculations involved in fully accounting for energy use and emissions associated with upstream activities for diesel fuel. GREET 1.5 was designed to perform circular calculations by means of the iteration calculation feature in Microsoft Excel. This feature allows GREET to draw data to use in one cell from some other cells (which, in turn, draw data from the first cell) for calculations being performed in the particular cell.

An iterative calculation in Excel requires each cell used in the calculation in the GREET model to have a valid value. An invalid value in a cell (say, characters assigned to a numeric value-required cell) can cause a nonrepairable Excel error throughout GREET. Caution must be taken to make sure each cell used in iterative calculations in Excel has a valid value.

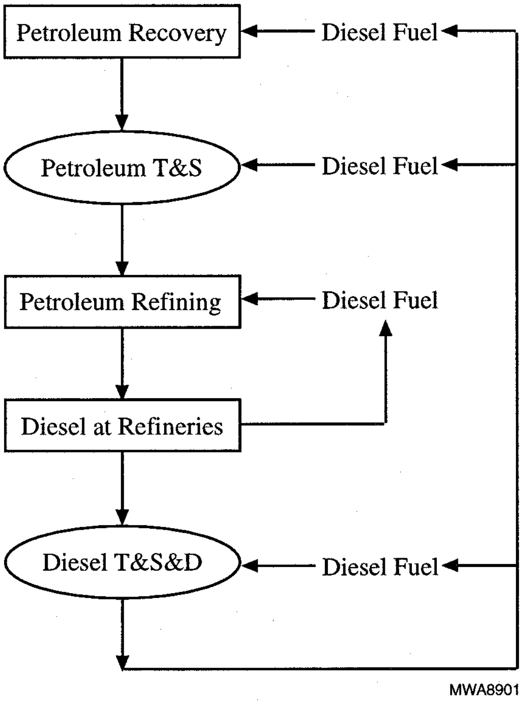

Figure 3.2 Closed-Loop Calculations of Upstream Energy Use and Emissions in GREET: Diesel Fuel Use in the Petroleum-to-Diesel Fuel Cycle

3.3.4 Aggregation of Energy Use and Emissions of Individual Upstream Stages for a Fuel Cycle

The above sections describe calculation of energy use and emissions per 10^6 Btu of fuel throughput for each individual upstream stage. The next step is to aggregate energy use and emissions of all upstream stages for a fuel cycle together so that energy use and emissions per 10^6 Btu of fuel delivered at the fuel pump can be calculated. In previous GREET versions, the aggregated value was obtained by adding the energy use and emissions from all upstream stages together. That method ignored the potential fuel loss during all stages that follow the stage that is being evaluated.

If there is no fuel loss during upstream activities, calculated energy use and emissions for each stage (in Btu/10^6 Btu or g/10^6 Btu throughput) can simply be added together to obtain total energy use and emissions per 10^6 Btu of fuel delivered at the final stage (e.g., at the fuel pump) — 10^6 Btu of feedstock would result in 10^6 Btu of fuel. However, if there is a fuel loss (from spillage, evaporation, or leakage), more than 10^6 Btu of a fuel in upstream stages is required to obtain 10^6 Btu at the final stage (e.g., at the fuel pump). The energy use and emissions calculated for each upstream stage (per 10^6 Btu of fuel throughput from the stage) need to be adjusted to the actual amount of fuel needed (greater than 10^6 Btu because of the loss) to deliver 10^6 Btu of the fuel in the final stage. The adjusted energy use and emissions for all the upstream stages can then be added together.

Delucchi (1997) graphically and mathematically demonstrated how precisely fuel-cycle energy and emissions should be calculated to account for the effects of fuel loss. On the basis of his equation and GREET's method of handling upstream energy use and emissions, the following equation was developed for GREET to account for fuel loss effects:

$$TEM_{up} = \sum_i EM_i \times K_{i-1} \times K_{i-2} \times \ldots \times K_1 \times K_0 , \qquad [3.8]$$

where

TEM_{up} = Total upstream emissions for a given fuel cycle (in g/10^6 Btu of fuel at fuel pump);
EM_i = Emissions from stage i, calculated in GREET by using Equation 3.7 (g/10^6 Btu of fuel throughput from stage i);
K_i = Fuel loss factor for stage i to take into account fuel loss during stage i; and
i = ith stage. Stages are numbered with the vehicle operation stage being stage 0. In other words, the vehicle operation stage is considered to be stage 0 and K_0 is always equal to one. The next stage above the vehicle operation stage, fuel distribution to fuel pumps, is considered to be stage 1, and so on).

For a given stage, its fuel loss factor (K_i) is calculated by using the following equation:

$$K_i = 1 + (1/efficiency_i - 1) \times Loss\_Share_i \qquad [3.9]$$

where

$efficiency_i$ = Energy efficiency of stage i, which is calculated as fuel output from the stage divided by total energy input to the stage (including feedstock fuel and process fuels); and
$Loss\_Share_i$ = The share of fuel loss out of total energy inputs for stage i.

The fuel loss share of total fuel use for many upstream stages is close to or equal to zero. Thus, the fuel loss factor (K_i) is close or equal to one in many cases. However, T&S of liquid fuels via vessels and transmission of gaseous fuels via pipelines are subject to fuel evaporation and/or leaks. In most cases, the amount of fuel evaporated and/or leaked is presented in emissions of VOCs or other compounds. In GREET, evaporative and/or leaked fuels, fuel loss shares, and fuel loss factors are considered together. That is, if transportation of a fuel is subject to a large amount of fuel evaporation or leaks, the transportation stage will have a large fuel loss share, and consequently a large fuel loss factor.

Note that the energy use and emissions calculated up to this point are the result of all upstream activities for delivering 1 million Btu of a fuel at the fuel pump.

3.3.5 Energy Use and Emissions of Vehicle Operations

Energy use and emissions of vehicle operations are calculated on a per-mile basis. Energy use (in Btu per mile or Btu/mi) is calculated from vehicle fuel economy. Emissions from ICEVs powered by conventional fuels (i.e., CG, RFG, CD, and RFD) are included in the GREET model for two reasons. First, HDTs fueled with diesel or gasoline are used during upstream stages for transportation and distribution of feedstocks and fuels, and their emissions need to be taken into account in calculating overall emissions during these stages. Second, emissions of benchmark light-duty GVs and diesel vehicles (DVs) are needed for calculating vehicular emissions for both benchmark vehicles and AFVs.

Emissions of VOCs, CO, and NO_x for benchmark GVs fueled with CG and benchmark DVs fueled with CD are calculated with EPA's Mobile 5b — the current version of EPA's Mobile model (the next version of the Mobile model, Mobile 6, will probably be released by end of 1999). Use of Mobile 5b is intended to estimate actual on-road emissions of motor vehicles. The Mobile 5b outputs are fed into GREET. PM_{10} emissions for benchmark vehicles are calculated by using EPA's Part 5 outside of the GREET model. Emissions of SO_x for both benchmark vehicles and AFVs are calculated inside the GREET model; for these calculations, we assume that all sulfur contained in each transportation fuel is converted into SO_2, except for fuel-cell vehicles, for which fuel sulfur is assumed to become solid waste. EPA's Mobile model does not estimate vehicular emissions of CH_4 and N_2O for any vehicle type. CH_4 emissions for benchmark vehicles can be indirectly estimated with Mobile 5b by estimating emissions of total hydrocarbons (THCs) and total nonmethane hydrocarbons (NMHCs); this approach was used in our study. Emissions of N_2O for benchmark vehicles are estimated in this study on the basis of existing data presented in Delucchi and Lipman (1996), a recent EPA report (EPA 1998c), and other published sources. Finally, combustion CO_2 emissions for all vehicle types are calculated by using a carbon balance approach (carbon contained in the fuel burned minus carbon contained in exhaust emissions of VOC, CO, and CH_4 is assumed to convert to CO_2). Because of the short residence time of VOCs and CO in the atmosphere (less than 10 days), the carbon contained in VOCs and CO is converted into CO_2 emissions in GREET.

In GREET, vehicular VOC emissions include exhaust, evaporation, running loss, resting loss, and refueling emissions, all of which are estimated with Mobile 5b. Vehicular PM emissions include exhaust, tire wear, and brake wear emissions, all of which are estimated with PART 5. Emissions of other pollutants are exhaust only.

In the GREET model, vehicular emissions of VOC, CO, NO_x, PM_{10}, CH_4, and N_2O from spark-ignition vehicles fueled with alternative fuel (SI-AFVs) are calculated by applying SI-AFV emission reduction rates to benchmark GV emissions. Emission reduction rates of SI-AFVs relative to those of benchmark GVs are estimated by using testing data for AFV emissions from different studies. (See Section 4 for assessment of AFV emissions reduction rates.)

Vehicular emissions of VOC, CO, NO_x, PM_{10}, CH_4, and N_2O from compression-ignition vehicles fueled with alternative fuels such as DME, FTD, and biodiesel (CI-AFVs) are calculated by applying CI-AFV emission reduction rates to those of benchmark DVs.

Energy consumption (in Btu/mi) is calculated by using the fuel economies of benchmark vehicles and AFVs. Benchmark GV fuel economies used in GREET are from the GV fuel economies predicted by DOE's EIA. The fuel economy for benchmark DVs is calculated by applying a fuel economy improvement rate — usually, conventional CI DVs can achieve a 10% improvement in gasoline-equivalent fuel economy over GVs, and CIDI DVs can improve fuel economy by 35%. The fuel economy of SI-AFVs is estimated by applying SI-AFV fuel economy changes (relative to SI GV fuel economy) to SI GV fuel economy. For CI-AFVs, the fuel economy is estimated by applying CI-AFV fuel economy changes (relative to CI DV fuel economy) to CI DV fuel economy. Fuel economy changes by DVs and AFVs are presented in

Section 4. Fuel economies calculated for each vehicle type in GREET are gasoline-equivalent fuel economies.

3.3.6 Total Fuel-Cycle Energy Use and Emissions for a Combination of Fuel and Vehicle Type

Section 3.3.4 presents calculations of upstream energy use and emissions in Btu and g/10^6 Btu of fuel delivered at the fuel pump. Section 3.3.5 presents calculations of energy use and emissions in Btu and g/mi traveled by each vehicle type. (Note that energy use by vehicles is calculated for total energy, fossil energy, and petroleum.) Now, energy use and emissions of upstream stages and downstream vehicle operations can be combined by converting upstream energy use and emissions from the per-10^6 Btu basis to the per-mile basis. The conversion is accomplished by dividing upstream energy use and emissions by vehicular per-mile energy use, which is calculated from vehicle fuel economy. Note that in the GREET model, the total energy use (not fossil energy use or petroleum use) by vehicles is used to convert the per-10^6 Btu upstream results into per-mile results in order to avoid potential under-accounting of energy use by vehicles fueled with nonfossil or nonpetroleum fuels.

GREET’s fuel-cycle results are presented on a per-mile basis. That is, the model estimates total fuel-cycle energy use and emissions for each mile traveled according to vehicle type fueled with a given fuel. In this regard, GREET is similar to Mobile — both GREET and Mobile estimate per-mile rates, rather than total energy use and emissions of a fleet of vehicles in a given year. To estimate the total emissions or energy use (often called emission and energy inventory), GREET per-mile results can be input into some vehicle stock and usage models.

Because per-mile upstream energy use and emissions are the per-million Btu energy use and emission result divided by Btu-per-mile fuel use (which is directly determined by vehicle fuel economy), vehicle fuel economy is one of the most significant factors in determining total fuel-cycle energy use and emissions.

3.3.7 Total and Urban Emissions for Five Criteria Pollutants

For the five criteria pollutants (VOC, CO, NO_x, PM_{10}, and SO_x) included in the GREET model, both the location and the amount of emissions are important, because these pollutants usually pose localized air pollution problems. (SO_x causes acid rain and poses other regional air pollution problems.) To account for the importance of emission locations, GREET is designed to estimate total emissions and urban emissions for the five criteria pollutants.

The term “total emissions” refers to total fuel-cycle emissions occurring everywhere, at every stage of a fuel cycle (calculated as described in the above sections). “Urban emissions” occur only within the boundaries of a given metropolitan area. GREET calculates urban emissions on the basis of these boundaries. The boundaries of an air control district can be used as the boundaries of an urban area in order to use the results from GREET to analyze air quality implications in an area. Readers should keep in mind that GREET estimates total and urban emission *rates,* not total and urban emission *inventory*. The estimated urban emission rates and estimated urban activity level from some other transportation activity models are needed in order to estimate the urban emission inventory that will occur with introduction of a transportation fuel or technology. Estimation of emission inventory is beyond the scope and capability of GREET. Ideally, urban emissions can be further disaggregated into grids of an urban area, and grid-specific emissions can be then used in air quality models to simulate air quality impacts of emissions that result from introducing an AFV. Separation of emission rates into total and urban rates in GREET is a simple, first step to provide some general idea of the differences in population exposure of emissions generated from a given fuel cycle.

Emissions from vehicle operations can occur within or outside of urban areas, depending on where vehicles are introduced and where they travel. In GREET, to calculate emission rates, we assumed vehicle miles traveled (VMT) by an AFV type occur in urban areas. That is, we assumed that AFVs are to be introduced to urban areas to make urban VMT. So, all emissions from vehicle operations are treated as urban emissions. In estimating urban emission inventory from mass introduction of a transportation fuel or vehicle technology, researchers must make assumptions regarding splits of urban VMT and rural VMT and consider only the urban VMT using the fuel or the technology. Wang et al. (1998) provides an example for calculating urban emission inventory with GREET-estimated urban emission rates.

Urban emissions of a given upstream stage are determined by facility locations, which are determined by feedstock availability, cost of transporting feedstock, and stationary emission regulations in urban areas. Because feedstocks (petroleum, NG, biomass, etc.) are usually located outside urban areas and because the cost of transporting them is usually much higher than that of transporting fuel (on the basis of the same amount of Btu delivered in the final fuel), upstream stages (except fuel distribution) are often located outside urban areas. Nonetheless, the split of upstream facilities located inside and outside the metropolitan area is fuel-, stage-, and region-specific. In GREET, a default split between urban and nonurban areas is provided for each upstream stage. The default splits were estimates for the United States as a whole. To use GREET to estimate emission rates for a specific area, data regarding the split of facility locations for that area must be collected. For example, to estimate urban emissions of gasoline production from petroleum refineries in Chicago, researchers must know how much gasoline that is consumed in the Chicago area is produced within and outside the Chicago area. Gasoline production within the Chicago area can be estimated on the basis of the capacity of the petroleum refineries located within the Chicago area minus the amount of gasoline shipped out of Chicago by petroleum refineries (net production in Chicago). The amount of gasoline produced outside the Chicago area (for Chicago consumption) can be estimated as the difference between the total gasoline demand and the net gasoline production in the Chicago area.

Direct use of emission rates estimated with GREET for air quality simulations may not be appropriate because emissions occur in different locations (as discussed above) and at different times. For a given quantity of fuel, production (upstream activities) occurs far ahead of consumption (vehicle operations). To accurately simulate air quality impacts, emissions that occurred at different times need to be differentiated; the exception is if a fuel has already achieved equilibrium in terms of production and consumption (i.e., the level of production and consumption stay relatively constant over time), which is not common for new fuels.

3.3.8 Summary: Results of Fuel-Cycle Energy Use and Emissions Calculated with GREET

GREET estimates fuel-cycle energy use and emission *rates* in Btu/mi and g/mi by various combinations of fuels and vehicle technologies. To provide clear information on the contribution of each upstream stage to total fuel-cycle energy use and emissions, GREET presents fuel-cycle energy use and emissions in three subcategories: feedstock, fuel, and vehicle operations (see Figure 3.1). The feedstock subcategory includes energy use and emissions associated with recovering, transporting, and storing energy feedstocks; the fuel subcategory includes energy use and emissions associated with producing, transporting, storing, and distributing product fuels; and the vehicle operation subcategory includes energy use and emissions directly related to vehicle operations. GREET presents per-mile energy use and emissions for each subcategory and the share of each subcategory to total fuel-cycle energy use and emissions. By using the estimated per-mile energy use and emissions, GREET then calculates percentage changes in energy use and emissions by alternative transportation fuels and or vehicle technologies relative to baseline GVs fueled with either CG or RFG.

As stated previously, GREET estimates energy use for total energy, fossil energy, and petroleum; total emissions and urban emissions of VOC, CO, NO_x, PM_{10}, and SO_x; and total emissions of CO_2, CH_4, and N_2O. In the default design of GREET, GHG emissions include CO_2, CH_4, and N_2O. However, GREET is designed for users to include VOC, CO, and NO_x as GHGs (see the table at the bottom of the *Fuel_Specs* sheet). If a GREET user considers VOC, CO, and NO_x as GHGs, the global warming potentials of the three can be provided to GREET, and GREET can automatically use these values to consider the three criteria pollutants as GHGs in GHG emissions calculations.

Besides providing a separate emissions estimate for each of the three GHGs now included in GREET (CO_2, CH_4, and N_2O), GREET combines these three GHGs with their GWPs to estimate CO_2-equivalent GHG emissions. GWPs are ratios of potential warming effects of other gases relative to CO_2. As the Intergovernment Panel on Climate Change (IPCC) acknowledged (IPCC 1996), the GWP is an attempt to provide a simple measure of the relative radioactive effects of various GHG emissions. The index is defined as the cumulative radioactive force between the present and some chosen time horizon caused by a unit mass of gas emitted now, expressed relative to that for CO_2. Table 3.4 presents GWPs for three GHGs included in GREET.

Table 3.4 Global Warming Potentials of Greenhouse Gases[a]

	Time Horizon		
Gas	**20 years**	**100 years**	**500 years**
CO_2	1	1	1
CH_4	56	21	6.5
N_2O	280	310	170

[a] Source: IPCC (1996).

Other major GHGs include halocarbons and halogenated compounds, aerosols (which, unlike other GHGs, have a cooling effect), and ozone. IPCC did not attempt to estimate GWP for aerosols. It maintained that the calculation of GWPs for VOC, CO, and NO_x (via the ozone warming effect) is not currently possible because the characterizations of many of the atmospheric processes involved are inadequate. There are large uncertainties in the GWPs already estimated for certain GHGs and a lack of understanding of the mechanism and effects associated with the gases for which GWPs have not been estimated. Some have argued that indirect effects of gases in the atmosphere and in other media should be taken into account in estimating GWPs (Delucchi 1997). Some economists have argued that economic damage indices, instead of GWPs, should be estimated and used for aggregating different GHGs (see Delucchi and Lipman 1996).

In 1997, major industrial countries signed the Kyoto Agreement to set GHG emission reduction goals for individual countries. The Kyoto Agreement adopted the IPCC-recommended GWPs for the 100-year time horizon for each country to use in calculating its baseline GHG emissions and projecting emission reductions. The Agreement included the three major GHGs. To evaluate various climate change mitigation policy options promoted by various governments, it is reasonable to use IPCC-estimated GWPs. So, default GWP values in GREET are those estimated by the IPCC under the 100-year time horizon. No GWP values are assigned to other gases, but GREET allows the user to change GWPs readily.

GHGs such as halocarbons and halogenated compounds are not included in GREET. Although these gases have very high GWPs, their overall contribution to GWP-weighted GHG emissions is small, because use of AFVs and advanced vehicle technologies will probably have little, if any, effect on motor vehicle emissions of these gases. Exclusion of these gases has little effect on changes in GHG emissions of AFVs and advanced vehicle technologies relative to baseline GVs.

Section 4
Parametric Assumptions and Their Data Sources

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

4.1 Petroleum-Based Fuel Cycles

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

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

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

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

Table 4.1 Specifications of Conventional and Reformulated Gasoline[a]

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

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

[b] As specified in the 1990 CAAA.

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

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

[e] NA = not available or not applicable.

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

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

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

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

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

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

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

4.1.1 Petroleum Recovery

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

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

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

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

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

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

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

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

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

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

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

[c] NE = not estimated.

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

Table 4.4 Shares of Process Fuels for Each Stage[a]

Stage	Crude	Diesel	Residual Oil	Gasoline	Still Gas	NG	Coal	Electricity	Fuel Loss
Crude recovery	1	15	1	2	0	62	0	19	0
Crude T&D	0	1	92	0	0	0	0	6	1
Crude refining	0	0	3	0	49	30	13	4	0
T&S&D									
Gasoline	0	39	33	0	0	15	0	11	3
Diesel	0	40	34	0	0	15	0	11	1
LPG	0	39	25	0	0	11	0	25	1
Residual oil	0	20	66	0	0	8	0	5	1

[a] Values are percentages based on the Btu contained in each fuel.

Emissions from combustion of process fuels are calculated by using the methods described in Section 3. During oil extraction and treatment, noncombustion emissions are produced. These so-called “process-related emissions” are estimated in addition to combustion emissions. The methods used for estimating some of the process-related emissions are described below.

CH_4 Emissions. In oil fields, NG is produced with crude. If the amount of NG produced is small or its quality is poor, the gas (called “associated gas”) is vented into the atmosphere primarily as CH_4 emissions (sometimes, gas is vented to help oil production) or flared as CO_2 emissions. According to EIA (1997a), 0.93×10^6 metric tons of CH_4 were vented to the atmosphere from U.S. production of oil and gas annually between 1992 and 1996. The majority of the vented gas should be associated with operation of oil wells — we assume that 90% of the vented gas (0.84×10^6 metric tons per year) is from oil wells. Between 1992 and 1996, the United States produced an average of 6.741×10^6 bbl/d of crude oil (EIA 1997b) and an annual average of $6{,}213 \times 10^9$ cubic feet (ft^3) of NG from oil wells (EIA 1997c). These values translate into an annual production rate of 13.53×10^{15} Btu of crude and 5.778×10^{15} Btu of NG from U.S. oil wells. That is, of the total energy produced from U.S. oil wells, 70% is oil and 30% NG. We use this ratio to allocate the total NG vented from oil wells between oil and gas. This allocation results in a total of 0.588×10^6 metric tons of CH_4 vented from oil wells for oil production. When an average production rate for U.S. crude of 6.741×10^6 bbl/d is used, we estimate the rate of CH_4 vented for oil production at 43.46 g of CH_4 vented per 10^6 Btu of crude produced in the United States.

As stated above, the United States imported more than half of its crude demand from other countries. Some of the U.S. imported crude is from the Middle East and Africa. In 1996, about 35% of total U.S. crude was imported from these two regions (EIA 1997b). In the Middle East and Africa, the amount of gas flared and vented per barrel of crude is much larger than the amount in the United States, simply because there is no gas distribution infrastructure to use the remote associated gas. We assume that the amount of flared and vented gas per barrel of imported oil is twice that associated with domestic oil production. We assumed that 60% of the U.S. crude would be imported after 2000. Thus, we increase the vented CH_4 emission rate as estimated above for U.S. crude recovery by 60% to account for the high CH_4 emissions from imported crude.

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

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

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

4.1.2 Crude Transportation and Storage

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

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

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

4.1.3 Crude Refining

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

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

Table 4.5 1996 U.S. Refining Product Outputs

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

Source: EIA (1997b).

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

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

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

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

4.1.4 Production of Oxygenates

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

Table 4.6 Properties of Four Oxygenates

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

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

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

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

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

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

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

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

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

[a] Values are per ton of product.

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

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

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

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

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

4.1.5 Transportation, Storage, and Distribution of Petroleum Products

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

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

4.2 Natural-Gas-Based Fuel Cycles

4.2.1 Brief Description of the Natural Gas Industry

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

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

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

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

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

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

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

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

[a] From EIA (1997c).

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

[c] Primarily from Canada.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

Several alternative schemes, such as POX, autothermal reforming (ATR), and plasma reforming, have been developed and used commercially to produce H_2. However, the majority of large-scale H_2 plants still employ SMR. We used SMR plants in our analysis. The SMR technology used in commercial H_2 plants involves conventional, one-step steam reforming carried out in high-alloy tubes placed inside a large NG-fired furnace. NG is normally preheated by the waste heat from the SMR reformer, and the feed gas is processed through a bed of ZnO sorbent (see above section on methanol production) to remove the sulfur (which poisons the reforming catalysts). Steam is added to the desulfurized NG feed, and the mixture of NG and steam is further preheated before entering the reformer, where CH_4 is converted into H_2, CO, and CO_2 by means of nickel-based reforming catalysts. The produced hot syngas, at a temperature of 900–930^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^{o}C helps produce predominately middle distillates and wax; an operating temperature of 330–350^{o}C helps produce gasoline and olefins. In any case, a mix of different hydrocarbon liquids is produced from the FTD synthesis stage.

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

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

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

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

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

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

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

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

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

Table 4.10 Worldwide Natural Gas Production and Flaring[a]

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

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

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

[c] From EIA (1998a).

[d] NA = not available.

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

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

4.2.3 Summary of Energy Efficiencies of Natural Gas-Based Cycles

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

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

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

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

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

[a] NE = not estimated.

[b] MeOH = methanol.

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

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

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

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

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

4.2.4 CH_4 Emissions during Natural Gas Production and Transportation

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

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

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

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

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

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

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

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

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

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

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

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

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

[f] NE = not estimated.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

4.3 Ethanol Production Cycles

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

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

4.3.1 Fuel and Chemicals Used for Corn and Biomass Production

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

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

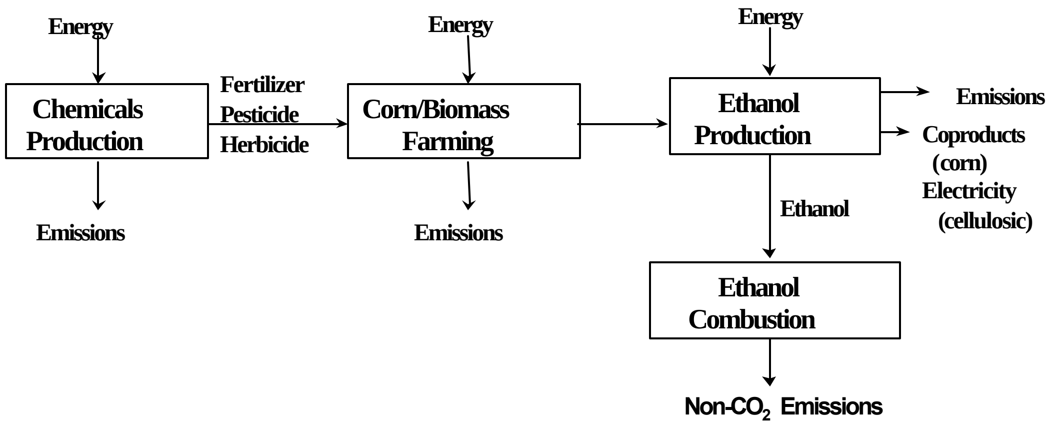

Figure 4.1 Stages Included in Renewable Ethanol Cycles

Table 4.16 Energy and Chemical Use for Corn Farming

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

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

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

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

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

[e] Not available.

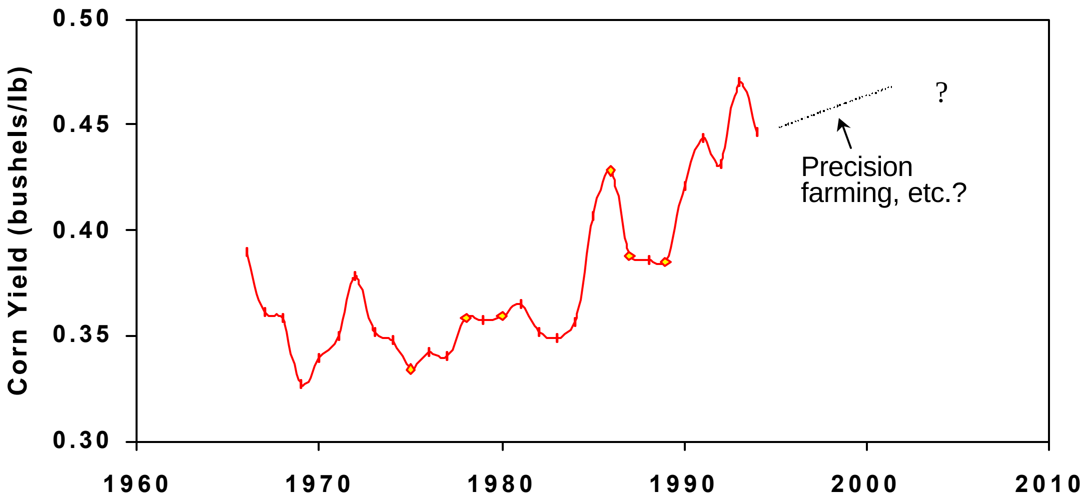

Figure 4.2 Historical Corn Productivity: Bushels of Corn Produced per Pound of Fertilizer Applied (3-year moving average; nitrogen, phosphate, and potash fertilizers are included here, on the basis of data provided by Shapouri [1997])

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

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

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

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

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

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

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

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

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

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

4.3.3 Energy Use of Manufacturing Fertilizers and Pesticides

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

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

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

Table 4.18 Energy Use and Fuel Shares for Fertilizer Manufacture

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

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

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

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

Table 4.19 Energy Use and Fuel Shares for Pesticide Manufacture

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

[a] NE = not estimated.

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

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

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

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

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

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

Assuming a 50/50 tonnage split between barge and rail transportation, the average energy use per ton of chemicals transported between plants and bulk centers is estimated to be 294,940 Btu/ton ($[1,060 \times 374 + 520 \times 372] \div 2$). 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).

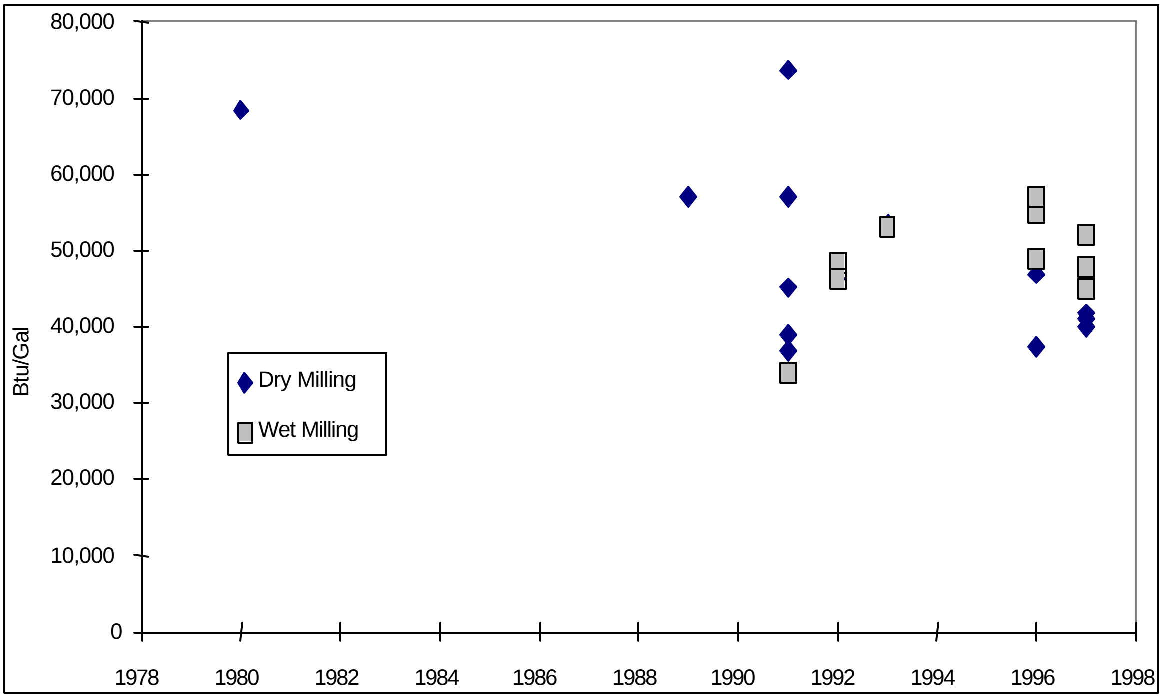

Figure 4.3 Historical Estimates of Energy Use in Ethanol Plants

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]

	Bone-Dry	
Coproduct	**lb/bu**	**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:

$$\text{DGS} = 44.658 - 11.083 \times \text{EtOH Yield} \tag{4.2}$$

where

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

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

Table 4.24 Coproduct Displacement Ratios[a]

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

4.3.8 Ethanol Transportation, Storage, and Distribution

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

4.4 Biodiesel Production

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

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

4.4.1 Soybean Farming

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

Table 4.26 U.S. Soybean Production and Deposition

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

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

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

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

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

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

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

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

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

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

4.4.2 Soybean Oil Extraction

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

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

Table 4.28 Inputs and Outputs of Soybean Oil Extraction Plants

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

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

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

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

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

4.4.3 Soy Oil Transesterification

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

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

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

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

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

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

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

[a] NE = not estimated.

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

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

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

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

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

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

4.5 Coal to Electricity

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

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

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

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

4.5.1 Energy Efficiencies

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

4.5.2 Noncombustion Emissions

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

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

4.6 Uranium to Electricity

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

4.7 Landfill Gases to Methanol

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

4.7.1 Energy Efficiencies

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

4.7.2 Emission Credits for Methanol Production

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

4.8 Electricity Generation

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

4.8.1 Combustion Technologies

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

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

4.8.2 Power Plant Conversion Efficiencies

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

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

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

[a] From Spath and Mann (1999).

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

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

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

[a] NE = not estimated.

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

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

4.8.3 Natural Gas-Fired Combined-Cycle Gas Turbines

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

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

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

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

4.8.4 Electric Generation Mixes

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

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

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

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

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

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

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

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

4.9 Vehicle Operations

4.9.1 Alternative Fuels and Vehicle Technologies Included in GREET

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

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

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

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

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

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

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

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

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

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

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

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

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

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

4.9.2 Gasoline Vehicles Fueled with Reformulated Gasoline

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

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

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

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

[a] From CARB (1998).

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

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

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

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

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

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

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

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

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

[e] For NMOG.

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

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

[h] NA = not available.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

[d] Assumed in this study.

4.9.3 Compressed Natural Gas Vehicles

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

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

		Change Relative to CG (%)					
Source	**Vehicle Model**	**Fuel Economy**	**Exhaust VOCs**	**CO**	**NO_x**	**CH_4**	**N_2O**
Battelle[b]	Chevy 5.7-L van[c]	-15.7	-81.7	-72.3	-57.6	3,626.1	-82.8
	Dodge 5.2-L van	-9.7	-93.8	-78.8	-45.1	808.3	-56.4
	Ford 4.9-L van	-2.2	-61.1	-69.0	105.4	2,167.2	35.2
AQIRP[d]	1992 GM 5.7-L Sierra Pickup[e]	-17.0	-86.5	-21.0	-74.6	1,311.5	NA[f]
	1993 Ford 4.6-L Crown Victoria [e]	-14.4	-80.0	-59.3	-47.7	1,223.3	NA
	1992 Chrysler 5.2-L B150 van[e]	-22.8	-89.1	-72.7	-8.6	900.0	NA
NREL[g]	92 and 94 MY 5.2-L Dodge B250 van	-7.9	-80.4	-45.4	-31.1	NA	NA
						NA	NA
SWRI[h]	1994 MY 4.3-L GMC 1500 pickup (aftermarket conversion)	5.5	-87.9	-18.3	-37.2	1,168.3	NA
GRI[i]	1996 MY Ford Crown Victoria dedicated	-4.7	-66.2	-4.6	-63.3	975.0	NA
	1995 MY Dodge Caravan dedicated	-14.1	-88.4	-83.2	-63.9	187.1	NA
	1994 Dodge Ram van dedicated	2.3	-93.1	-12.4	36.3	478.7	NA
	1996 Dodge Ram van dedicated	-6.1	-83.1	-87.0	-32.9	278.7	NA
Ford[j]	1997 Ford 5.4-L F-250 pickup dedicated	-16.0	-91.0	-39.0	-50.0	NA	NA
	1997 Ford 5.4-L E-250 van dedicated	-18.0	-95.0	-65.0	-65.0	NA	NA
Honda[k]	1998 Honda Civic GX	-6.1	-96.4	-90.9	-85.4	NA	NA
EPA certification[l]	1995 Dodge Caravan dedicated	NA	-80.0	-85.8	-39.2	NA	NA
	1995 Dodge Caravan dedicated	NA	-85.7	-82.1	-37.5	NA	NA
	1996 Ford Crown Victoria dedicated	NA	-57.1	32.8	-88.2	NA	NA
	1996 Ford 2.0-L Ford Contour[l,m]: bi-fuel	NA	15.7	4.8	100.0	NA	NA
	1997 Ford Crown Victoria dedicated	NA	-51.7	-50.0	-86.7	NA	NA
	1997 Chrysler minivan dedicated	NA	-85.8	-72.9	-52.6	NA	NA
	1998 Ford Crown Victoria dedicated	NA	-86.5	-35.1	34.8	NA	NA
	1998 Chevy C2500 pickup bi-fuel (OEM)	-4.6	-77.3	-23.0	-12.1	1,472.0	NA
	1998 Chevy C2500 pickup bi-fuel (OEM)	-5.9	-77.1	-29.4	-4.2	1,437.0	NA
	1998 Chevy Cavalier bi-fuel (OEM)	NA	-52.2	-15.8	0	NA	NA
	1998 Chevy Cavalier bi-fuel (OEM)	NA	-77.1	-29.4	-4.2	NA	NA
	1998 Ford 2.0-L Contour: bi-fuel[k]	NA	-66.7	-23.7	-8.2	NA	NA
	1998 Ford 2.0-L Contour: bi-fuel[k]	NA	-42.0	-16.7	0.0	NA	NA
Santini and Saricks[n]	Passenger cars	NA	-76.0	-33.0	0.0	NA	NA
	Pickup trucks	NA	-81.0	3.0	-6.0	NA	NA
	Standard vans	NA	-95.0	-76.0	-63.0	NA	NA
NREL[o]	1996 Ford Crown Victoria	-11.6	-67.9	-62.8	-2.1	1,760	NA
NGVC[p]	1996 Ford Crown Victoria	NA	-20.0	-69.8	-58.5	23,00	NA

Continued

Table 4.39 (Cont.)

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

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

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

[d] From AQIRP (1995b).

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

[f] NA = not available.

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

4.9.4 Methanol Vehicles

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

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

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

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

[b] From AQIRP (1994).

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

[d] NA = not available.

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

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

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

4.9.5 Ethanol Vehicles

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

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

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

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

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

[b] From AQIRP (1995c).

[c] NA = not available.

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

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

4.9.6 Liquefied Petroleum Gas Vehicles

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

4.9.7 Other Vehicle Types

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

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

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

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

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

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

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

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

[e] NA = not available.

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

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

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

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

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

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

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

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

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

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

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

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

[b] NA = not available.

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

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

4.9.8 Summary

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

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

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

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

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

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

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

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

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

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

Table 4.45 (Cont.)

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

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

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

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

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

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

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

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

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

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

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

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

Table 4.46 (Cont.)

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

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

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

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

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

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

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

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

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

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

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

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

Section 5
Model Layout

GREET 1.5, developed as a multidimensional spreadsheet model in Microsoft Excel 97, consists of 15 sheets; these sheets are briefly described below. If the GREET model is available to the reader, it is helpful to browse through it in Excel while reading this section.

Overview. This sheet presents a brief summary of each of the sheets in GREET to introduce their functions. It also presents some key notes for running GREET and our disclaimers. First-time users need to read this sheet before proceeding with GREET simulations.

EF. Here, “EF” represents emission factors. In this sheet, emission factors (in g/10^6 Btu of fuel burned) are presented for individual combustion technologies that burn NG, residual oil, diesel, gasoline, crude oil, LPG, coal, and biomass. These emission factors are used in other sheets of the GREET 1 series model (and in the GREET 2 and 3 series models) to calculate emissions associated with fuel combustion in various upstream stages. For each combustion technology, emission factors are presented (in g/10^6 Btu) for VOCs, CO, NO_x, PM_{10}, SO_x, CH_4, N_2O, and CO_2. As stated in Section 3, GREET’s emission factors for VOCs, CO, NO_x, PM_{10}, CH_4, and NO_2 are derived primarily from the EPA’s AP-42 document. Emission factors for CO_2 are calculated in the GREET model from carbon contained in a given fuel minus carbon contained in VOCs, CO, and CH_4 emitted during combustion of the fuel.

For the sake of calculating CO_2 emissions, the carbon ratios of VOCs, CO, and CH_4 are listed in this sheet. The carbon ratios for CO and CH_4 are precisely calculated from their molecular compositions, but the ratio for VOCs is estimated on the basis of an assumption about the aggregate composition of individual hydrocarbon species in exhaust gases. SO_x emission factors for the combustion of NG, gasoline, diesel, crude, and LPG are calculated by assuming that all the sulfur contained in these fuels is converted to SO_2. The calculations of CO_2 and SO_x emissions of fuel combustion are built into appropriate cells in this sheet.

This sheet encompasses 43 combustion technologies. For many of the combustion technologies, emission factors are presented in terms of so-called “current” and “future” factors. For a given combustion technology, current emission factors applied to the technology reflect requirements of the 1990 Clean Air Act Amendments. These requirements were usually in place by the mid-1990s. Future emission factors apply to a future technology with some further emission controls as appropriate. To determine future emission factors, we first assessed the need for controlling emissions of certain pollutants for a given combustion technology. We then studied the EPA’s AP-42 document and other documents to determine the appropriate emission control measures applicable to the given technology.

To estimate emissions for a given fuel-cycle stage over time, a GREET user can gradually increase the share of the future technologies for a given combustion technology to reflect implementation of further emission control technologies in the future. That is, when the users simulate a more remote future year, they can assume a larger share of future emission factors. When running GREET to generate results in this report, we assumed 20% of the current emission factors and 80% of the future emission factors for a given combustion technology (say, NG-fired industrial boiler) for the evaluation of near-term transportation fuels and technologies in calendar year 2005. For the evaluation of long-term fuels and technologies in calendar year 2015, we increased the share of future emission factors to 100%. That is, we phased out current emission factors by 2015.

Fuel_Specs. This sheet presents specifications for individual fuels. Lower and higher heating values (in Btu/gal, Btu/scf, or Btu/ton for liquid, gaseous, or solid fuels, respectively), fuel density (in g/gal, g/scf, or g/ton for liquid, gaseous, or solid fuels, respectively), carbon weight ratio, and sulfur weight ratio are specified for each fuel. Sulfur content for each fuel is presented in ppm and actual ratio by weight. Users can put sulfur content (in ppm) into GREET, and the actual ratio is changed in GREET accordingly.

The parametric values for these fuel specifications are needed to estimate energy consumption and emissions, as well as for conversions among mass, volume, and energy content. Fuel specifications are presented for crude oil, CG, RFG (both California and federal phase 2 RFG), CD, RFD, residual oil, methanol, ethanol, LPG, LNG, DME, dimethoxy methane (DMM) (the current version of GREET does not calculate energy use and emissions for DMM — these may be included in a future version), biodiesel, FTD, liquid hydrogen, MTBE, ETBE, TAME, butane, isobutane, isobutylene, propane, NG liquids, still gas, NG, gaseous hydrogen, coal, coking coal, woody biomass, and herbaceous biomass. The information in this sheet is called on by all the other sheets in GREET.

GREET uses the LHVs of fuels for its calculations. Some studies have used HHVs. Both LHVs and HHVs are presented in GREET. If HHVs are required for the user's own calculations, those values can be copied to the calculation cells designed in this sheet, and GREET will then take HHVs into account automatically. However, changes from LHVs to HHVs requires changing emission factors (in g/10^6 Btu) from LHVs to HHVs too.

GWPs for individual GHGs also are presented in this sheet. The GWPs are used in GREET to combine emissions of GHGs together to calculate CO_2-equivalent emissions. As stated in Section 3, GREET uses the IPCC-adopted GWPs. That is, GWP is 1 for CO_2, 21 for CH_4, and 310 for N_2O. At present, GREET assigns GWPs of zero to VOCs, CO, and NO_x, although cells are designated in this sheet for assigning GWPs to these three gases. If users decide to test other GWP values for the six pollutants, they can simply change the default GWP values in this sheet.

Petroleum. This sheet is used to calculate upstream energy use and emissions of petroleum-based fuels. Six petroleum-based fuels are included in GREET: CG, RFG, CD, RFD, LPG, and residual oil. Residual oil itself is not a motor vehicle fuel; it is included here for calculating upstream energy use and emissions associated with producing transportation fuels and electricity.

The petroleum sheet, together with the other eight upstream calculation sheets (*NG, Ag_Inputs, EtOH, BD, Coal, Uranium, LF_Gas,* and *Electric*), follows the calculation logistics described in Section 3 and presented in Figure 5.1. For each upstream stage, the model uses assumptions about shares of fuel combustion technologies, energy efficiencies, total and urban emission shares, and shares of process fuels. Energy consumption (by process fuel) is calculated on the basis of energy efficiencies and process fuel shares. For each stage, energy use is calculated for total energy (all process fuels and energy in feedstocks), fossil energy (petroleum, NG, and coal), and petroleum. Emissions are calculated from the amount of a given process fuel used, combustion technology shares for the given fuel, and emission factors for each combustion technology. In addition, such noncombustion emissions as those from fuel leakage and evaporation, gaseous fuel venting, and chemical reactions are estimated, as applicable. Energy use and emissions are then summarized for two aggregate groups: feedstock- and fuel-related stages. Urban emissions of the five criteria pollutants are calculated by considering the split between urban facilities and nonurban facilities for a given upstream activity.

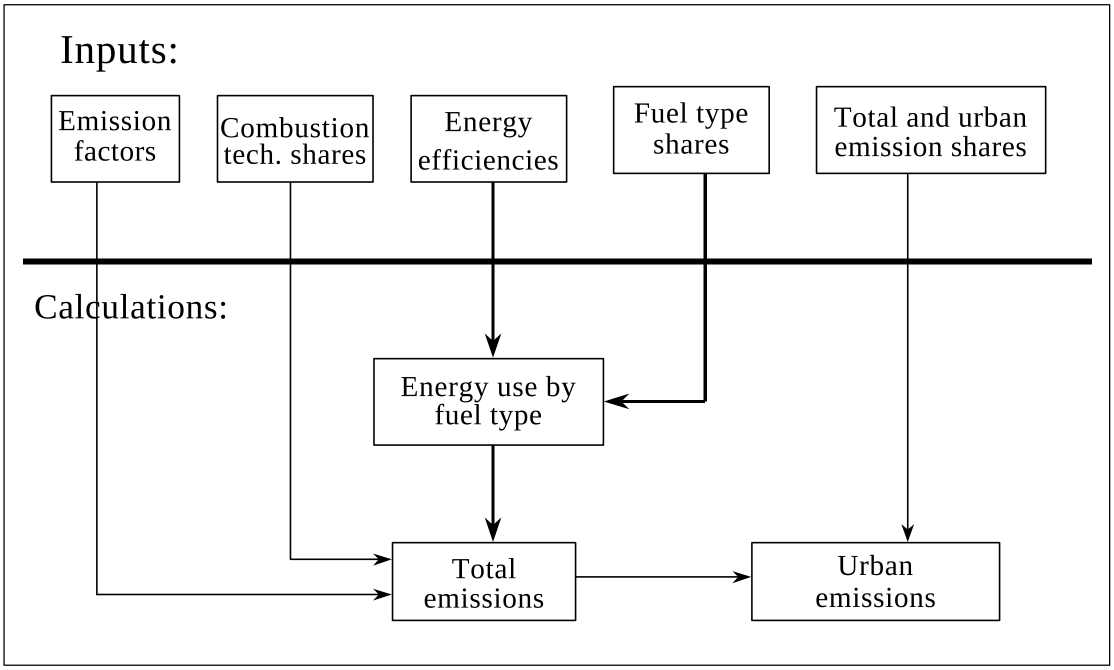

Figure 5.1 GREET's Logistics for Upstream Energy Use and Emissions Calculations

The nine upstream sheets are constructed in similar ways. Most sheets are divided into four sections. The first section (the so-called scenario control and key input parameters section) presents key assumptions about a fuel cycle and the control parameters for multipathway fuels to select which pathway is to be simulated; some of the nine sheets (*Ag_Inputs, Coal, Uranium, and LF_Gas*) lack this section. The second section presents shares of combustion technologies for a given fuel burned during a given upstream stage. Depending on specific cases to be simulated, one can change combustion technology shares in this section. The third section presents, for each upstream stage, assumptions about energy efficiencies, urban emission shares, a loss factor (which is used to combine energy and emission results from different stages together), and shares of process fuels. With these input parameters, GREET calculates energy use and emissions for each stage in this section. Also, if applicable, assumptions about the so-called “noncombustion emissions” for some stages are presented in this section. The fourth section presents a summary of the energy use and emissions as calculated in the third section, divided into two groups: feedstock- and fuel-related stages for individual fuel cycles. The summarized results in this section are called on by other parts of the GREET model.

For the petroleum sheet, the scenario control section presents the assumptions of MTBE content of CG and the oxygen requirements of RFG. Currently, MTBE is added to CG to maintain an adequate level of octane, even though there is no oxygen requirement for CG. On average, CG contains 2% MTBE by volume. This percentage has been input into the petroleum sheet as a default value. Note that the recent discovery in California of water contamination associated with MTBE may eliminate the use of MBTE in CG in the future. The oxygen requirements of California and federal RFG are also based on regulations that could change in the future.

GREET allows use of MTBE, ETBE, TAME, or ethanol in RFG to meet oxygen requirements. As the scenario control section of the petroleum sheet shows, users can simply select one of the four ethers for use in their GREET simulations.

NG. This sheet presents calculations of energy use and emissions for NG-based fuels, namely CNG, LNG, LPG, methanol, DME, FTD, and H_2. Fuel cycles from shared gas to methanol, DME, and FTD are also presented. For convenience, the fuel cycle that consists of producing renewable H_2 from solar energy via water electrolysis is presented in this section, too. For H_2 fuel cycles, H_2 can be produced in either gaseous or liquid form; either form may be selected for simulation. If it is assumed that gaseous H_2 produced in central plants is used, the produced gaseous H_2 is transported via pipelines to service stations and is compressed and used to fuel vehicles. If liquid H_2 is assumed, gaseous H_2 is first liquefied at H_2 plants, and the liquid H_2 is stored and transported cryogenically.

In the scenario control section, users can choose to simulate a specific pathway for a fuel that can be produced from multiple pathways. For example, users can choose whether liquid H_2 is produced from NG or solar energy; whether gaseous H_2 is produced from NG in centralized plants, from NG in refueling stations, or from solar energy in centralized plants; and whether liquid or gaseous H_2 is used in motor vehicles. Users can also choose whether methanol is produced from NG, flared gas, or landfill gas; whether LPG is produced from NG, crude, or any combination of both; and whether FTD and DME are produced from NG or flared gas. Because CO_2 sequestration in NG-H_2 plants is a key factor in determining GHG emission impacts of NG-to-H_2 pathways, the assumption of CO_2 sequestration is presented in this section, too. LPG, methanol, and gaseous H_2 could be used for stationary applications as well as for vehicle applications. In order that stationary applications of these fuels are not affected by their production pathways for vehicle applications, stationary application pathways are presented for these fuels separately from pathway assumptions for vehicle applications.

Ag_Inputs. This sheet presents calculations for agricultural chemicals, including synthetic fertilizers and pesticides. Three fertilizers are included: nitrogen, P_2O_5, and K_2O. Pesticides include herbicides and insecticides. Furthermore, herbicides include atrazine, metolachlor, acetochlor, and cyanazine, four major herbicides for which energy intensity data are available. Many other herbicides are used for farming, but no energy intensity data are available for them. A generic insecticide is assumed in GREET, because there are no specific energy intensity data for individual insecticides. The fertilizers and pesticides are used in growing corn, soybeans, woody biomass, and herbaceous biomass. Calculated energy use and emissions for these chemicals are used to calculate energy use and emissions of ethanol (produced from corn, woody biomass, and herbaceous biomass) and biodiesel (produced from soybeans). Average energy use and emissions of herbicides are presented in this sheet for corn, soybeans, woody biomass, and herbaceous biomass, with assumed shares of individual herbicide types for each crop.

This sheet also includes calculations of energy use and emissions associated with transportation of chemicals from manufacturing plants to farms. Transportation of chemicals is separated into three steps: manufacturing plants to bulk distribution terminals, to mixers, and then to farms. Calculations of energy use and emissions are separated for each step, each chemical, and each crop. In this way, the user's own data can be readily inputted for application of an individual chemical to an individual crop type.

EtOH. This sheet calculates energy use and emissions for fuel cycles that involve producing ethanol from corn, woody biomass, and herbaceous biomass. In the first section (the scenario control and key input parameters section), users can elect to:

1. Simulate ethanol production from corn [(a) dry milling plants, (b) wet milling plants, or (c) a combination of both];
2. Simulate ethanol production from corn and biomass [(a) ethanol from corn, (b) ethanol from woody biomass, (c) ethanol from herbaceous biomass, or (d) a combination of the three];
3. Include changes in CO_2 emissions from land-use changes due to corn and biomass farming; and
4. Use the market-value-based approach or the displacement approach to estimate energy and emission credits of coproducts from corn ethanol plants.

This section also presents parametric assumptions regarding ethanol yield in corn ethanol plants (in gal/bu of corn), the shares of NG and coal as process fuels in corn ethanol plants, electricity credits from cellulosic ethanol plants (in kWh/gal of ethanol produced), and ethanol yield in cellulosic ethanol plants (in gal/dry ton of biomass). For the market-value-based approach and the displacement approach of dealing with coproducts of corn ethanol, this section presents key assumptions to be used to estimate coproduct credits for each approach.

In the calculation section, energy and emissions are calculated for corn farming in Btu/bu and g/bu of corn produced and for biomass farming in Btu/dry ton and g/dry ton of biomass produced. Energy use and emissions of ethanol production are calculated in Btu/gal and g/gal of ethanol produced. Energy use and emissions from different stages are converted into Btu/10^6 Btu and g/10^6 Btu of ethanol produced in the summary section, on the basis of ethanol yield of plants (gal/bu of corn or gal/dry ton of biomass) and the ethanol's energy content.

BD. This sheet calculates energy use and emissions associated with producing BD from soybeans. Allocation of energy use and emissions between BD and its coproducts is needed for this fuel cycle. The allocation assumptions for soybean farming, soy oil extraction, and soy oil transesterification are presented in the scenario control section. In GREET 1.5, the market-value-based approach is used to allocate energy use and emissions between BD and its coproducts. Also, assumptions about soybeans required per pound of soy oil produced and soy oil required per pound of BD produced are presented in this section.

Energy use and emissions are calculated for soybean farming in Btu/bu and g/bu of soybeans produced and for soy oil extraction or transesterification in Btu/lb and g/lb of soy oil or biodiesel produced. In the summary section, energy use and emissions for each stage are converted into Btu/10^6 Btu and g/10^6 Btu of biodiesel produced by using yield data for each stage and the energy content of biodiesel.

Coal. This sheet is used to calculate energy use and emissions for coal mining and transportation. The results are used in other upstream calculation sheets.

Uranium. This sheet is used to calculate energy use and emissions for uranium mining, transportation, and enrichment. The results are used in the electricity sheet for calculating upstream energy use and emissions of nuclear electric power plants.

LF_Gas. This sheet presents energy and emission calculations for the fuel cycle that consists of producing methanol from landfill gases. It is assumed in GREET that without methanol production, landfill gases would otherwise be flared. Flaring the gases produces significant amounts of emissions. The emissions offset by methanol production are taken into account as emission credits for methanol production. On the other hand, emissions from methanol combustion are taken into account during vehicle operation.

Electric. This sheet is used to calculate energy use and emissions associated with electricity generation for production of transportation fuels (where electricity is used) and for operation of EVs and grid-connected HEVs. The layout of this sheet is different from other upstream sheets. In the scenario control section, there is a control variable for selection of either GREET-calculated electric power generation emission factors or user-provided emission factors. In calculating electric power generation emission factors, GREET takes into account the type of fuel used, the type of generation technologies used, and emission controls employed. For a specific electric utility system, if a user has measured emission factors for electricity generation by the system, the user can input the system-specific, measured emission factors in section 4 of this sheet to override the GREET-calculated emission factors.

The next section presents information about average and marginal electric generation mixes, combustion technology shares for a given fuel, power-plant conversion efficiencies, and urban and total emission splits. The average electric generation mix is used to calculate emission factors of electric generation for determining energy use and emissions associated with producing transportation fuels (i.e., the upstream activities). The marginal electric generation mix is used to calculate emission factors for EVs and the grid electric operations of grid-connected HEVs. In other words, the average generation mix is used for electricity use in stationary sources; the marginal mix, for electricity use by motor vehicles.

The third section of the electric sheet presents electricity loss during electricity transmission and distribution. Section 4 presents the method for calculating g/kWh emission rates for oil-, NG-, and coal-fired power plants by GREET or user-input power plant emission rates. Section 5 presents power plant emission rates in g/kWh for a utility system with a given generation mix. Section 6 presents power plant energy use and emissions per million Btu of electricity generated from an electric utility system. Section 7 presents energy use and emissions of both electric power plants and activities prior to electric power plants.

Vehicles. This sheet is used to calculate energy use and emissions associated with vehicle operations. The sheet is constructed in three sections. In the first (scenario control) section, for methanol and ethanol FFVs and dedicated methanol and ethanol vehicles, users can specify the content of methanol or ethanol in fuel blends. For FTD and biodiesel blended with diesel, users can specify the content of FTD or biodiesel in fuel blends. The VMT split between grid electricity operation and ICE operation for grid-connected HEVs also is presented in the scenario control section.

Methanol and ethanol blends can be CG- or RFG-based. As RFG use becomes widespread in the future, methanol and ethanol will likely be blended with RFG. An option provided in this section allows users to decide whether CG or RFG will be blended with methanol and ethanol. Another option allows users to decide whether CD or RFD will be blended with FTD and BD.

In the second section, fuel economy and emission changes associated with AFVs and advanced vehicle technologies relative to baseline gasoline or diesel vehicles are presented. Since fuel economy and emissions of baseline vehicles are different for near- and long-term technology options, fuel economy and emission changes for near- and long-term technologies are presented separately in this section.

The third section calculates energy use and emissions associated with vehicle operations for individual vehicle types. The fuel economy of baseline GVs is input in this section. Emissions of baseline gasoline and diesel vehicles are calculated with EPA’s MOBILE 5b and PART 5 and input here. Energy use of other vehicle types (including diesel vehicles) is calculated on the basis of baseline GV fuel economy and relative change in fuel economy between GVs and AFVs. Emissions of AFVs are calculated from emissions of GVs or DVs and relative emission changes of AFVs. For alternative fuels applicable to spark ignition engines, the emissions are calculated from baseline GV emissions. For alternative fuels applicable to CI engines (DME, FTD, and biodiesel), the emissions are calculated from baseline DV emissions. Again, energy use and emissions are presented for near- and long-term technologies separately.

For the two biofuels (ethanol and biodiesel), combustion CO_2 emissions are treated as being zero in this section, because the CO_2 emitted to the atmosphere is simply the CO_2 obtained from the atmosphere by corn and soybean plants during photosynthesis. Alternatively, CO_2 emissions from combustion of ethanol or biodiesel can be calculated here, and a CO_2 emission credit can be assigned to farming of corn or soybeans.

Results. Fuel-cycle energy use and emissions for each individual vehicle type are calculated in this sheet. For each vehicle type, energy use and emissions are calculated for three stages: feedstock (including recovery, transportation, and storage), fuel (including production, transportation, storage, and distribution), and vehicle operation. Shares of energy use and emissions by each of the three stages are also calculated in this section. For the five criteria pollutants, both urban emissions and total emissions (emissions occurring everywhere) are calculated in this section.

The first section presents per-mile energy use and emissions for all near-term technology options. The second section presents those for all long-term technology options. In the third and fourth sections of this sheet, changes in fuel-cycle energy use and emissions by individual AFV types are calculated. The changes for near-term options are calculated against conventional GVs fueled with CG; the changes for long-term options are against conventional GVs fueled with RFG.

Graphs. In this sheet, Section 1 graphically presents shares of energy use and emissions by feedstock, fuel, and vehicle operations for each vehicle type. Again, charts are presented for near- and long-term technologies separately. In this section, each chart represents a vehicle or fuel technology.

Section 2 of this sheet presents changes in energy use and emissions by vehicle type. Vehicle and fuel technologies are separated into four groups: near-term technologies, long-term SI and SIDI vehicles, long-term CIDI vehicles and CIDI hybrid electric vehicles, and long-term electric vehicles and fuel-cell vehicles. Each chart in this section represents a particular energy or emission item.

Within the GREET model, some cells present default assumptions used for fuel-cycle energy and emission calculations, while others are logic calculations. Users have the option to change any of the default assumptions. The cells that contain critical assumptions are colored yellow so that users can easily distinguish these assumptions from logic calculations and can change key assumptions as necessary.

Section 6
Fuel-Cycle Energy Use and Emissions Results

This section presents results of energy use and emissions associated with individual alternative fuels and advanced vehicle technologies, as calculated by GREET 1.5. To generate the results presented in this section, we used default assumptions (presented in previous sections) about upstream fuel production activities and vehicle operations. As stated throughout this report, the default assumptions used in GREET are based on our research. Readers need to pay attention to the assumptions as much as to the results. It is preferable that, for their own analyses, users collect the necessary data, make changes to critical assumptions in GREET, and produce their own results. However, the results presented in this section do represent our best judgments, made on the basis of our research.

6.1 Near- and Long-Term Alternative Fuels and Vehicle Technologies

Among the fuels and vehicle technologies included in GREET, some are already available in the marketplace and being used, while others, still in the research and development stage, must overcome technological hurdles or are not marketable because of cost and infrastructure constraints. Economics and market readiness of these long-term technologies are beyond the scope of this study.

Thus, evaluation of fuel-cycle energy and emission impacts of alternative fuels and advanced technologies is conducted separately for near-term and long-term technologies. The separation is necessary because, over time, baseline conventional technologies will be improved, and the improved baseline conventional technologies should be used to analyze the impacts of long-term technologies. For our analysis, near-term technologies are those already available in the United States, and long-term technologies could become available around the year 2010 (see Tables 4.35, 4.45, and 4.46 for near- and long-term technologies).

To evaluate near-term technologies, we assumed that they would be applied to vehicles produced around 2001 (MY 2001) and that the baseline MY 2001 GVs would meet National Low-Emission Vehicle (NLEV) emission standards. The NLEV program, adopted by EPA in the spring of 1998, is a voluntary program in which 9 northeast U.S. states and 23 automakers participate. The program requires that NLEV vehicles begin to be introduced to the northeast United States in MY 1999 and to the rest of the United States (except California) in MY 2001 (EPA 1998a). The NLEV program allows manufacturers to certify vehicles fueled by gasolines like the federal Phase 2 RFG.

Table 6.1 presents NLEV emission standards and Tier 1 standards currently in place. Tier 1 emission standards were fully in effect beginning in MY 1996. Under the NLEV program, each automaker is subject to fleet average NMOG standards. In the Northeast United States, the fleet average NMOG standards are 0.148 g/mi for MY 1999 and 0.095 g/mi for

Table 6.1 Tier 1 and NLEV Emission Standards for Light-Duty Vehicles and Trucks (in g/mi)[a]

Vehicle		THC	NMHC	NMOG	CO	NO$_x$	PM[b]	HCHO[c]
5 Years/50,000 Miles Useful Life								
Cars	Tier 1	NE[d]	0.25	NE	3.4	0.4	0.08	NE
	TLEV	NE	NE	0.125	3.4	0.4	NE	0.015
	LEV	NE	NE	0.075	3.4	0.2	NE	0.015
	ULEV	NE	NE	0.040	1.7	0.2	NE	0.008
LDT1[e]	Tier 1	NE	0.25	NE	3.4	0.4	0.08	NE
	TLEV	NE	NE	0.125	3.4	0.4	NE	0.015
	LEV	NE	NE	0.075	3.4	0.2	NE	0.015
	ULEV	NE	NE	0.040	1.7	0.2	NE	0.008
LDT2[e]	Tier 1	NE	0.32	NE	4.4	0.7	0.08	NE
	TLEV	NE	NE	0.160	4.4	0.7	NE	0.018
	LEV	NE	NE	0.100	4.4	0.4	NE	0.018
	ULEV	NE	NE	0.050	2.2	0.4	NE	0.009
LDT3[f]	Tier 1	NE	0.32	NE	4.4	0.7	NE	NE
LDT4[f]	Tier 1	NE	0.39	NE	5.0	1.1	NE	NE
10 Years/100,000 Miles Useful Life								
Cars	Tier 1	NE	0.31	NE	4.2	0.6	0.10	NE
	TLEV	NE	NE	0.156	4.2	0.6	0.08	0.018
	LEV	NE	NE	0.090	4.2	0.3	0.08	0.018
	ULEV	NE	NE	0.055	2.1	0.3	0.04	0.011
LDT1[e]	Tier 1	0.80	0.31	NE	4.2	0.6	0.10	NE
	TLEV	NE	NE	0.156	4.2	0.6	0.08	0.018
	LEV	NE	NE	0.090	4.2	0.3	0.08	0.018
	ULEV	NE	NE	0.055	2.1	0.3	0.04	0.011
LDT2[e]	Tier 1	0.80	0.40	NE	5.5	0.97	0.10	NE
	TLEV	NE	NE	0.200	5.5	0.9	0.10	0.023
	LEV	NE	NE	0.130	5.5	0.5	0.10	0.023
	ULEV	NE	NE	0.070	2.8	0.5	0.05	0.013
LDT3[f]	Tier 1	0.80	0.46	NE	6.4	0.98	0.10	NE
LDT4[f]	Tier 1	0.80	0.56	NE	7.3	1.53	0.12	NE

[a] Source: EPA Office of Mobile Sources Internet Home Page.

[b] PM emission standards are applied to diesel vehicles only.

[c] HCHO = formaldehyde.

[d] NE = not established.

[e] Definitions of LDT1 and LDT2 are different between emission regulations and emission estimations in Mobile 5b. In emission regulations, LDT1 is defined as an LDT with a loaded vehicle weight of 0–3,750 lb and with a GVW below 6,000 lb; LDT2 is defined as an LDT with a loaded vehicle weight of 3,750–5,570 lb and with a GVW below 6,000 lb. For emission estimation in Mobile 5b, LDT1 is defined as an LDT with a GVW of less than 6,000 lb; LDT2 is defined as an LDT with a GVW of 6,000–8,500 lb.

[f] LDT3 and LDT4 for emission regulations are the LDT2 defined in Mobile 5b simulations. Both LDT3 and LDT4 have a GVW of 6,001–18,500 lb. LDT3 has a loaded vehicle weight of 0–3,750 lb, and LDT4 has a GVW of greater than 3,750 lb.

MY 2000 and beyond for cars and LDT1; and 0.190 g/mi for MY 1999 and 0.124 g/mi for MY 2000 and beyond for LDT2. Nationwide, the fleet average NMOG standards are 0.075 g/mi for cars and LDT1 and 0.100 g/mi for LDT2, both beginning in MY 2001. Nationwide, NLEV vehicles will be required to account for at least 25% of total vehicle sales in MY 2001, 50% in MY 2002, and 85% in MY 2003 and beyond.

To represent the average lifetime emissions of MY 2001 vehicles, we estimate, with Mobile 5b and Part 5, per-mile emissions of the MY 2001 baseline vehicles (i.e., gasoline and diesel vehicles) in calendar year 2006, when these vehicles will accumulate about half of their lifetime VMT. Consequently, GREET 1.5 was run for calendar year 2006 for near-term technologies.

The GREET 1 series is designed to estimate fuel-cycle energy use and emissions for passenger cars, light-duty trucks 1 (LDT1s, pickups, minivans, passenger vans, and sport utility vehicles with a GVW up to 6,000 lb), and light-duty trucks 2 (LDT2s with a GVW between 6,001 and 8,500 lb). Energy use and emissions are estimated for passenger cars, LDT1s, and LDT2s separately. Tables 4.45 and 4.46 indicate that changes in fuel economy and emissions of alternative-fuel transportation technologies are assumed to be the same for passenger cars and LDT1s, while changes for LDT2s are different. Consequently, relative changes in fuel-cycle energy use and emissions for passenger cars and LDT1s are the same. On the other hand, fuel economy (affecting per-mile upstream emissions) and per-mile vehicular emissions are distinctly different for the three vehicle classes. Thus, changes in absolute amount (i.e., Btu/mi and g/mi) for energy and emissions are also different for the three.

To run GREET 1.5 for calendar year 2006, where both current and future emission factors are applied to a given combustion technology, we assumed a split of 20%/80% between current emission factors and future emission factors to calculate average emission factors for the combustion technology. Table 6.2 summarizes key assumptions about upstream activities for evaluating near- and long-term technologies.

To estimate fuel-cycle energy and emission impacts of long-term technologies, GREET was run in calendar year 2015 for MY 2010 vehicle technologies. Besides changes in vehicle operations emissions, changes were also made in the assumptions about upstream activities. For the long-term technology evaluation, future emission factors alone were used for combustion technologies; current emission factors were zeroed out. For the four NG-based fuels (methanol, DME, FTD, and H_2), energy efficiencies in production plants were increased, or steam credit was assumed (see Table 6.2). Energy intensity for manufacturing fertilizers and pesticides was reduced by 15%. Farming energy use (in Btu/bu) and use of fertilizers and pesticides (in g/bu) were reduced by 10% for both corn and soybean farming. Energy use in ethanol plants and biodiesel plants was reduced by 10%. The share of NG as the process fuel in ethanol plants was increased, while the share of coal was decreased. Ethanol yield was increased from 2.6 to 2.7 gal/bu of corn for dry milling corn ethanol plants and from 2.5 to 2.6 gal/bu for wet milling ethanol plants. The electric generation mix projected in EIA's *Annual Energy Outlook 1998* (EIA 1997d; see Table 4.34) for 2015 was used.

Table 6.2 Key Parametric Assumptions for Near- and Long-Term Technologies (in the exact forms accepted by GREET 1.5)

Item	Near-Term (2006)	Long-Term (2015)
Upstream fuel combustion: current emission factors	20%	0%
Upstream fuel combustion: future emission factors	80%	100%
Methanol plant efficiency: NG as feedstock	68%	65%[a]
Methanol plant efficiency: flared gas as feedstock	65%	65%
FTD plant efficiency: NG as feedstock	54%	53%[b]
FTD plant efficiency: flared gas as feedstock	52%	52%
DME plant efficiency: NG as feedstock	69%	68%[c]
DME plant efficiency: flared gas as feedstock	66%	66%
NG to H_2 plant efficiency: central plant	73%	67%[d]
NG to H_2 plant efficiency: refuel station production	65%	65%
Liquid H_2 liquefaction efficiency	82%	85%
Chemical manufacture energy intensity	Default values	85% of default values
Energy use intensity: corn and soybean farming	Default values	90% of default values
Chemical use intensity: corn and soybean farming	Default values	90% of default values
Energy use intensity: biodiesel production	Default values	90% of default values
Corn ethanol plants		
Ethanol yield: dry milling (gal/bu)	2.6	2.7
Ethanol yield: wet milling (gal/bu)	2.5	2.6
Dry milling production share	1/3	1/2
Wet milling production share	2/3	1/2
Ethanol plant energy use intensity	Default values	90% of default values
Share of coal as process fuel: dry milling plants	50%	20%
Share of coal as process fuel: wet milling plants	80%	50%
Electricity generation		
Electric generation mix (see Table 4.34)	2005 mix	2015 mix
NG combined cycle: % of NG capacity	30%	45%
Advanced coal technology: % of coal capacity[e]	5%	20%
Baseline GVs[f]		
Fuel economy (mpg): cars/LDT1/LDT2	22.4/16.8/14.4	24/18/15.4
Baseline Fuel	CG	FRFG2
Exhaust VOC emissions	NLEV emissions	Tier 2 emissions
Evaporative VOC emissions	NLEV emissions	Tier 2 emissions
Exhaust CO emissions	NLEV emissions	Tier 2 emissions
Exhaust NO_x emissions	NLEV emissions	Tier 2 emissions
Exhaust PM emissions	NLEV emissions	Tier 2 emissions
Baseline DVs[f]		
Exhaust VOC emissions	NLEV emissions	Tier 2 emissions
Exhaust CO emissions	NLEV emissions	Tier 2 emissions
Exhaust NO_x emissions	NLEV emissions	Tier 2 emissions
Exhaust PM emissions	NLEV emissions	Tier 2 emissions

[a] Plus 111,000 Btu of steam credit per million Btu of methanol produced.

[b] Plus 264,000 Btu of steam credit per million Btu of FTD produced.

[c] Plus 44,000 Btu of steam credit per million Btu of DME produced.

[d] Plus 269,000 Btu of steam credit per million Btu of H_2 produced.

[e] Advanced coal technologies for electric power plants include PFB/CC and IGCC, both of which have high energy conversion efficiency and low emissions.

[f] Fuel economy and emissions for baseline vehicles are for the 55/45 combined cycle. Fuel economy values are on-road-adjusted results. Emission estimates for baseline vehicles are presented in Section 6.2.

Corn ethanol is produced from both wet milling and dry milling facilities. At present, two-thirds of total U.S. ethanol is produced from wet milling plants and one-third from dry milling plants. For near-term corn ethanol, we used this split to combine the results of wet and dry milling plants. In the future, more dry milling plants will likely be built than wet milling plants, partly because capital requirements are lower for dry milling plants and because some states offer tax incentives for building small dry milling plants. Thus, for long-term corn ethanol production, we assumed 50% from wet milling plants and 50% from dry milling plants.

We assumed that long-term fuels and vehicle technologies would be applied to MY 2010 vehicles and that MY 2010 baseline GVs would meet the Tier 2 emission standards proposed by EPA (EPA 1999). Table 6.3 presents the proposed Tier 2 standards for cars, light LDTs (LLDTs), and heavy LDTs (HLDTs). In the Tier 2 proposal, EPA defined LLDTs as LDTs with a GVW of 0–6,000 lb and HLDTs as LTDs with a GVW of 6,000–8,500 lb. That is, the newly defined LLDTs are Mobile 5b-defined LDT1, and the newly defined HLDTs are Mobile 5b-defined LDT2. Note that beginning in MY 2009, all cars, LLDTs, and HLDTs will be subject to the same Tier 2 standards. For Tier 2, EPA proposed that evaporative emission standards be reduced by 50%.

6.2 Mobile 5b and Part 5 Runs

We used EPA’s Mobile 5b and Part 5 to generate per-mile emission rates for baseline GVs and DVs. For evaluation of near-term fuels and technologies, we used Mobile 5b and Part 5 to generate emissions estimates for LEVs that are six years old and have accumulated about 64,000 miles, which represents the mid-point of a vehicle’s lifetime. In accordance with EPA’s guidelines for estimating emission inventories, we estimated emissions of VOCs and NO_x for summer conditions and emissions of CO for winter conditions. PM emissions are not affected by ambient temperature, so we assumed summer conditions to generate PM emissions by using the Part 5 model.

In 1998, EPA developed an NLEV version of Mobile 5b to estimate emission impacts of the NLEV program (EPA 1998b). We used the Mobile 5 NLEV version to generate emissions of baseline GVs and DVs. Together with the NLEV program, the enhanced phase 2 on-board diagnosis system (OBDII) will be required for light-duty vehicles. In Mobile 5 NLEV runs, we included OBDII and an annual I/M program. However, our tests with Mobile 5 NLEV showed that OBDII overrode the I/M programs. That is, as long as OBDII is included, the I/M program does not offer any additional emission benefits for OBDII-equipped cars. We suspected that too many emission credits are assigned to OBDII in Mobile 5 NLEV. The new evaporative test procedure, which considers multiple diurnal tests, took effect in MY 1996. Cold CO emission standards were assumed for LEV vehicles. Beginning in 1998, an on-board refueling vapor recovery system was also assumed. We considered these requirements as well. Because of limitations of vehicle types in Mobile 5 NLEV, we had to make some adjustments outside of Mobile 5 NLEV. The footnotes in Table 6.4 describe these adjustments.

Vehicle emissions and fuel economy (especially emissions) are significantly affected by vehicle driving cycles. While emissions are regulated under the federal urban driving schedule (FUDS), corporate average fuel economy (CAFE) is regulated under the FUDS and the highway cycle. We ran Mobile 5b and Part 5 separately for the FUDS and the highway driving cycle, then averaged the results of the two cycles together with 55% mileage for the FUDS and 45% for the highway cycle. This "55/45 combined cycle" is used for the CAFE regulation. This cycle is more appropriate for estimating energy use and GHG emissions than for estimating criteria pollutant emissions. If the user's main focus is on criteria pollutants, the FUDS and other urban driving cycles should be used.

Mobile 5b and Part 5 cannot be used to estimate emissions for the proposed Tier 2 vehicles, so we applied changes in emission standards from LEVs to Tier 2 to emissions of LEVs to estimate emissions of Tier 2 vehicles. As Tables 6.1 and 6.3 show, there are large reductions in emission standards between LEVs and Tier 2 vehicles. Table 6.5 lists these reductions, which are especially significant for NO_x and PM. Also note that reductions for HLDTs are much higher than those for cars and LLDTs. We used these reduction rates to estimate on-road emissions of Tier 2 vehicles from on-road emissions of LEVs. The footnotes in Table 6.4 describe our estimates.

Table 6.3 Proposed Tier 2 Vehicle Emissions Standards for Passenger Cars and Light-Duty Trucks[a,b]

Bin	NMOG	CO	NO_x	PM	HCHO
Tier 2 Light-Duty Vehicle Standards[c]					
7	0.125	4.2	0.20	0.02	0.018
6	0.090	4.2	0.15	0.02	0.018
5	0.090	4.2	0.07	0.01	0.018
4	0.055	2.1	0.07	0.01	0.011
3	0.070	2.1	0.04	0.01	0.011
2	0.010	2.1	0.02	0.01	0.004
1	0.000	0.0	0.00	0.00	0.000
Interim Standards for Non-Tier 2 Cars and LLDTs during Tier 2 Phase-In[d]					
5	0.156	4.2	0.60	0.06	0.018
4	0.090	4.2	0.30	0.06	0.018
3	0.055	2.1	0.30	0.04	0.011
2	0.090	4.2	0.07	0.01	0.018
1	0.000	0.0	0.00	0.00	0.000
Interim Standards for HLDTs during Tier 2 Phase-In[e]					
5	0.230	4.2	0.60	0.06	0.018
4	0.180	4.2	0.30	0.06	0.018
3	0.156	4.2	0.20	0.02	0.018
2	0.090	4.2	0.07	0.01	0.018
1	0.000	0.0	0.00	0.00	0.000

[a] Source: EPA (1999).

[b] The emission standards are in g/mi for a useful lifetime of 120,000 mi.

[c] For cars and LLDTs, the Tier 2 standards will be phased in beginning in MY 2004 and will be fully in effect in MY 2007. For HLDTs, the standards will be phased in beginning in MY 2008 and will be fully in effect in MY 2009. That is, beginning in MY 2009, cars, LLDTs, and HLDTs will be subject to the Tier 2 standards. The three vehicle groups together will be subject to a fleet average NO_x standard of 0.07 g/mi for each automaker.

For cars and LLDTs, the minimum Tier 2 vehicle sales percentages are 25% in MY 2004, 50% in MY 2005, 75% in MY 2006, and 100% in MY 2007 and beyond. For HLDTs, the minimum sales percentages are 50% in MY 2008 and 100% in MY 2009 and beyond.

[d] These standards will be applied to non-Tier 2 cars and LLDTs between MY 2004 and 2006. The non-Tier 2 vehicles together will be subject to a fleet average NO_x standard of 0.30 g/mi for each automaker. The maximum non-Tier 2 vehicle sales percentage will be 75% in MY 2004, 50% in MY 2005, 25% in MY 2006, and 0% in MY 2007 and beyond.

[e] These standards will be applied to HLDTs between MY 2004 and 2008. These vehicles together will be subject to a fleet average NO_x standard of 0.20 g/mi for each automaker. The minimum sales percentages of HLDTs subject to the interim standards are 25% in MY 2004, 50% in MY 2005, 75% in MY 2006, 100% in MY 2007, 50% (maximum) in MY 2008, and 0% in MY 2009 and beyond. The remainder of the new HLDT fleet between MY 2004 and 2007 will be subject to Tier 1 standards.

Table 6.4 Fuel Economy and Emissions Rates of Baseline Gasoline and Diesel Vehicles[a]

Item	Gasoline Car	Gasoline LDT1[b]	Gasoline LDT2[b]	Diesel Car[c]	Diesel LDT1[c,d]	Diesel LDT2[c,d]
Near-Term Vehicles: LEVs Fueled with CG or CD[e]						
Economy (mpgeg)[f]	22.4	16.8	14.4	30.2	22.7	19.4
Emissions (g/mi)						
Exhaust VOC	0.080	0.091	0.629	0.080[g]	0.091[g]	0.540
Evaporative VOC	0.127	0.107	0.156	0.000	0.000	0.000
CO	5.517	8.247	16.846	1.070	1.139	1.208
NO_x	0.275	0.381	1.173	0.600[g]	0.600[g]	1.224
Exhaust PM_{10}	0.012	0.015	0.015	0.100	0.100	0.109
Brake and tire wear PM_{10}	0.021	0.021	0.021	0.021	0.021	0.021
CH_4[h]	0.084	0.090	0.090	0.011	0.014	0.017
N_2O[i]	0.028	0.033	0.040	0.016	0.024	0.032
Long-Term Vehicles: Tier 2 Vehicles Fueled with FRFG2 or RFD[j]						
Economy (mpgeg)[k]	24.0	18.0	15.4	36	27	23.1
Emissions (g/mi)						
Exhaust VOC	0.062	0.062	0.080	0.049	0.080	0.112
Evaporative VOC	0.063	0.063	0.078	0.000	0.000	0.000
CO	2.759	2.759	5.518	2.759	5.518	5.518
NO_x	0.036	0.036	0.135	0.063	0.135	0.180
Exhaust PM_{10}[l]	0.010	0.010	0.020	0.010	0.020	0.020
Brake and tire wear PM_{10}	0.021	0.021	0.021	0.021	0.021	0.021
CH_4[m]	0.065	0.065	0.091	0.011	0.014	0.017
N_2O[n]	0.028	0.033	0.040	0.016	0.024	0.032

[a] Fuel economy and emissions for baseline vehicles are for the 55/45 combined cycle.

[b] Mobile 5b defines light-duty gasoline truck 1 (LDGT1) as vehicles with a GVW of up to 6,000 lb and light-duty gasoline truck 2 (LDGT2) as vehicles with a GVW between 6,001 and 8,500 lb.

[c] For diesel vehicles, we assumed DI engines for both near-term and long vehicles.

[d] Mobile 5b does not estimate emissions for diesel LDT1. Instead, the model estimates emissions for LDTs, which include both LDT1 and LDT2. However, most diesel trucks are classified as LDT2. So we used Mobile 5b-estimated diesel LDT emissions as emissions for diesel LDT2. We estimated emissions of diesel LDT1 as the average emissions of diesel cars and diesel LDT2, except as noted.

[e] LEVs were assumed to be fueled with conventional gasoline or conventional diesel. PM emissions were estimated by using Part 5, and other emissions were estimated by using the NLEV version of Mobile 5b, except as noted.

[f] Fuel economies of LEVs are from EIA's 1998 Annual Energy Outlook (AEO98) projections for MY 2001 new vehicles (EIA 1997d) with supplemental data from EPA (Heavenrich and Hellman 1996). Near-term direct injection diesel vehicle fuel economy, presented in mpgeg, is estimated from GV fuel economy and the assumed 35% mpgeg improvement between GVs and DVs.

[g] The NLEV version of Mobile 5b does not estimate emissions of diesel cars and diesel LDT1 that are subject to NLEV standards. For exhaust VOC emissions, we assumed that emissions from diesel cars and LDT1 will be the same as those for GVs and LDT1, respectively. For exhaust NO_x emissions, we assumed that diesel cars and LDT1 will meet the TLEV NO_x standard (0.6 g/mi; see Table 6.1) under the NLEV program.

[h] CH_4 emissions were calculated as the difference between THC and NMHC, both of which were estimated by using Mobile 5b.

[i] N_2O emissions are from EPA (1998c).

Table 6.4 (Cont.)

[j] Emissions from Tier 2 GVs were estimated on the basis of emissions from gasoline-fueled LEVs and reductions in emission standards between gasoline-fueled LEVs and Tier 2 GVs (see Table 6.5), except as noted below.

Emissions from Tier 2 gasoline-fueled LDT1 were assumed to be the same as those for Tier 2 gasoline cars (except as noted), because both cars and LDT1 were assumed to be subject to Bin 3 of the Tier 2 proposal (see Table 6.5).

Emissions from Tier 2 gasoline-fueled LDT2 were estimated on the basis of emissions from Tier 2 gasoline cars and the difference in emission standards between Bin 3, to which Tier 2 gasoline cars are subject and Bin 6, to which LDT2 are subject (see Table 6.5), except as noted.

Emissions from Tier 2 diesel cars, diesel-fueled LDT1, and diesel-fueled LDT2 were estimated using a method similar to that used to calculate emissions from Tier 2 gasoline-fueled LDT2.

[k] We projected fuel economy of MY 2010 vehicles on the basis of MY 2000 vehicle fuel economy and mpg improvement between MY 2001 and 2010 for passenger cars, as predicted in EIA's AEO98 (7% improvement over the period) (EIA 1997d).

[l] PM emissions from Tier 2 vehicles were assumed to be at the applicable PM standard levels.

[m] CH_4 emissions from Tier 2 GVs were calculated on the basis of the differences in exhaust VOC emissions. CH_4 emissions from Tier 2 diesel vehicles were assumed to be the same as CH_4 emissions from diesel-fueled LEVs, because diesel-fueled LEVs already have low CH_4 emissions.

[n] N_2O emissions from Tier 2 vehicles were assumed to be the same as emissions from LEV vehicles, because no N_2O emission data are available for Tier 2 vehicles, and because only small improvements in N_2O emissions have been shown with further NO_x emission control (see EPA 1998c).

Table 6.5 Reductions in Emissions Standards for Tier 2 Vehicles Relative to LEVs[a]

Vehicle	Applicable Tier 2 Bin Assumed[b]	Exhaust VOC	Evaporative VOC	CO	NO_x	PM_{10}[c]
Gasoline cars	3	22%	50%	50%	87%	NA[d]
Gasoline LLDTs	3	36%	50%	57%	90%	NA
Gasoline HLDTs	6	82%	50%	39%	88%	NA
Diesel cars	4	39%	NA	50%	77%	88%
Diesel LLDTs	6	18%	NA	13%	63%	78%
Diesel HLDTs	7	75%	NA	39%	84%	82%

[a] Reductions in emission standards were calculated from standards presented in Tables 6.1 and 6.3. For LLDTs, the average of standards for LDT1 and LDT2 in Table 6.1 was used. For HLDTs, the average of standards for LDT3 and LDT4 in Table 6.1 was used.

[b] Under the Tier 2 proposal, an automaker can certify its vehicles to any of the seven bins, as long as its fleet average NO_x standard is below 0.07 g/mi. Consequently, many combinations of vehicle sales among the seven bins exist for automakers to select for meeting the average NO_x standard. The applicable Tier 2 bin that we selected for each vehicle group, one of the many possible combinations, represents our assessment of technological potentials.

[c] PM emission standards in Table 6.1 are applied to DVs only. For LEVs, PM emissions from GVs are not constrained by PM standards. Reductions for PM emission standards for GVs were therefore not calculated here.

[d] NA = not applicable.

Relative to GVs, DVs have inherently higher NO_x and PM emissions. The Tier 2 bins we have chosen for DVs are based on the assumption that automakers will certify DVs at higher emission levels for NO_x and PM. On the basis of this assumption, NO_x and PM emissions from DVs are about twice as high as those from GVs (except PM emissions from diesel cars).

Table 6.4 presents estimated fuel economy and vehicular emissions of baseline GVs and DVs for passenger cars, LDT1, and LDT2. As stated above, emissions of near-term baseline vehicles were estimated by using the Mobile 5 NLEV version and assuming that baseline passenger cars and LLDTs will meet NLEV standards and that HLDTs will meet Tier 1 standards. Because most of the United States will still use CG and because no RFD will be introduced in the near term, we assumed use of CG in baseline GVs and CD in baseline DVs.

The long-term baseline vehicles were assumed to meet the newly proposed Tier 2 standards. To help meet the standards, Tier 2 vehicles were assumed to be fueled with FRFG2 and RFD. Tier 2 vehicle emissions were estimated on the basis of LEV emissions and emission standard reductions between LEVs and Tier 2 vehicles (see Table 6.5).

In particular, for Tier 2 gasoline-fueled cars, emissions of exhaust VOCs, evaporative VOCs, CO, and NO_x were estimated from LEV emissions and emission standard reductions from NLEVs to Tier 2 vehicles (as presented in Table 6.5). Exhaust PM emissions for Tier 2 gasoline-fueled cars were assumed to be at the PM standard for Tier 2 Bin 3. Exhaust CH_4 emissions were estimated from LEV CH_4 emissions and exhaust VOC emission reductions between LEVs and Tier 2 Bin 3. There are no data on N_2O emissions from Tier 2 vehicles. Because NO_x emissions are significantly reduced for Tier 2 vehicles, we expect that N_2O emissions could increase, on the basis of nitrogen mass balance calculations. On the other hand, emission control technologies and clean gasoline and diesel will help reduce N_2O emissions. We assumed the same N_2O emissions for LEVs and Tier 2 vehicles.

We assumed that Tier 2 gasoline-fueled LDT1 (LLDTs, as defined in the Tier 2 proposal) would be subject to Tier 2 Bin 3, the same bin to which Tier 2 gasoline cars are subject. Emissions of the former were assumed to be the same as those of the latter, except for N_2O, for which emissions from Tier 2 LDT1 were assumed to be the same as those from LEV LDT1.

We estimated emissions from Tier 2 gasoline-fueled LDT2 on the basis of Tier 2 gasoline-fueled car emissions and emission standard differences between Tier 2 Bin 3 (to which gasoline-fueled cars are subject) and Bin 6 (to which gasoline-fueled LDT2 are subject), except as noted. VOC evaporative emissions from Tier 2 gasoline-fueled LDT2 are estimated on the basis of LEV gasoline LDT2 and emission standard differences between LEV LDT2 and Tier 2 LDT2.

Emissions from Tier 2 diesel-fueled cars, diesel-fueled LDT1, and diesel-fueled LDT2 were calculated using a method similar to that used to calculate emissions from Tier 2 gasoline-fueled LDT2, except as noted. Tier 2 CH_4 emissions from DVs were assumed to be the same as those for LEV diesel vehicles, because DVs in general have very low CH_4 emissions.

PM emissions for all Tier 2 vehicles were assumed to be at the applicable Tier 2 PM standard levels.

Table 6.4 shows the results of our emissions estimates for baseline GVs and DVs. For the near-term baseline vehicles, there are large increases in emissions from LDT1 to LDT2. This is because, while LDT1 will be subject to the NLEV standards, LDT2 will continue to be subject to the Tier 1 standards (see Table 6.1; the NLEV program does not cover Mobile 5-defined LDT2). From the near-term to the long-term baseline vehicles, substantial reductions in emissions result from Tier 2 standards. If Tier 2 standards are implemented, baseline vehicle emissions will be significantly reduced.

6.3 Contribution of Each Stage to Fuel-Cycle Energy Use and Emissions

The 21 figures that follow present shares of fuel-cycle energy use and emissions by fuel-cycle stage for each combination of fuels and vehicles. These figures, created automatically in GREET 1.5, are meant to help readers readily grasp the key stage for a given combination in terms of fuel-cycle results. For this purpose, fuel-cycle activities are grouped into three stages: feedstock-related, fuel-related, and vehicle operation stages. The feedstock-related stage includes feedstock recovery, transportation, and storage. The fuel-related stage includes fuel production, transportation, storage, and distribution. The vehicle operation stage includes vehicle refueling and operations.

The 21 figures described below are based on calculations for passenger cars. Among the three light-duty vehicle types (passenger cars, LDT1s, and LDT2s), stage contributions to total fuel-cycle energy use and emissions are similar.

6.3.1 Near-Term Technologies

Figure 6.1 shows stage contributions for conventional GVs. Three types of gasoline (CG, FRFG2, and CARFG2) are included in GREET, and the two RFG types can be produced with MTBE, ETBE, and ethanol. Stage contributions are similar for these options. The figure here presents the results for CG. As the figure shows, vehicle operations contribute the most to total fuel-cycle results, except for emissions of SO_x and CH_4. Petroleum refining accounts for the largest amount of SO_x emissions. Crude recovery in oil fields produces a large amount of CH_4 emissions.

Figure 6.2 shows stage contributions for DVs. Overall, the pattern for DVs is similar to that for GVs, except for PM_{10}, NO_x, and VOCs, for which DV operation accounts for most of the total emissions.

Figure 6.3 shows the results for dedicated CNG vehicles. As one might expect, vehicle operation involves no petroleum use and a very small amount of SO_x emissions. NG compression, which consumes a considerable amount of electricity and NG, produces most of the fuel-cycle SO_x emissions. NG recovery and processing produce a large amount of CH_4 emissions. For NO_x emissions, feedstock- and fuel-related activities account for more than half of the total fuel-cycle emissions. Upstream VOC emissions account for a large share of total

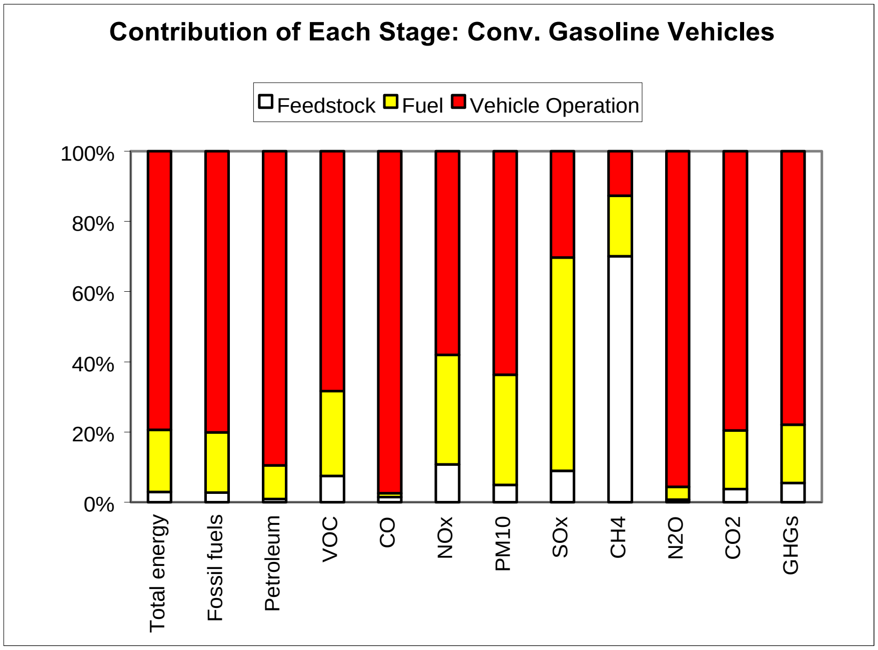

Figure 6.1 Shares of Fuel-Cycle Energy Use and Emissions by Stage: Converted Gasoline Vehicles

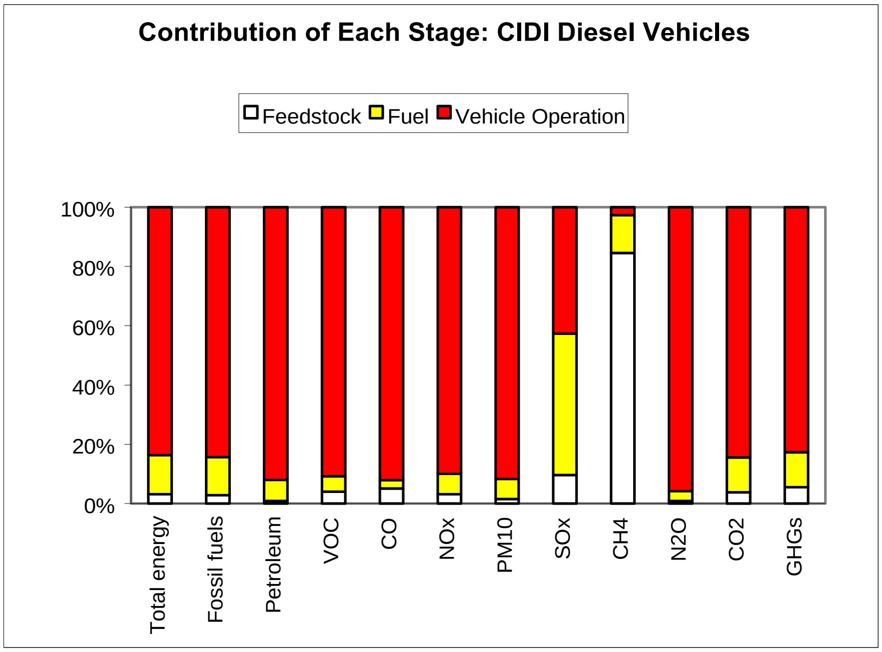

Figure 6.2 Shares of Fuel-Cycle Energy Use and Emissions by Stage: CIDI Diesel Vehicles

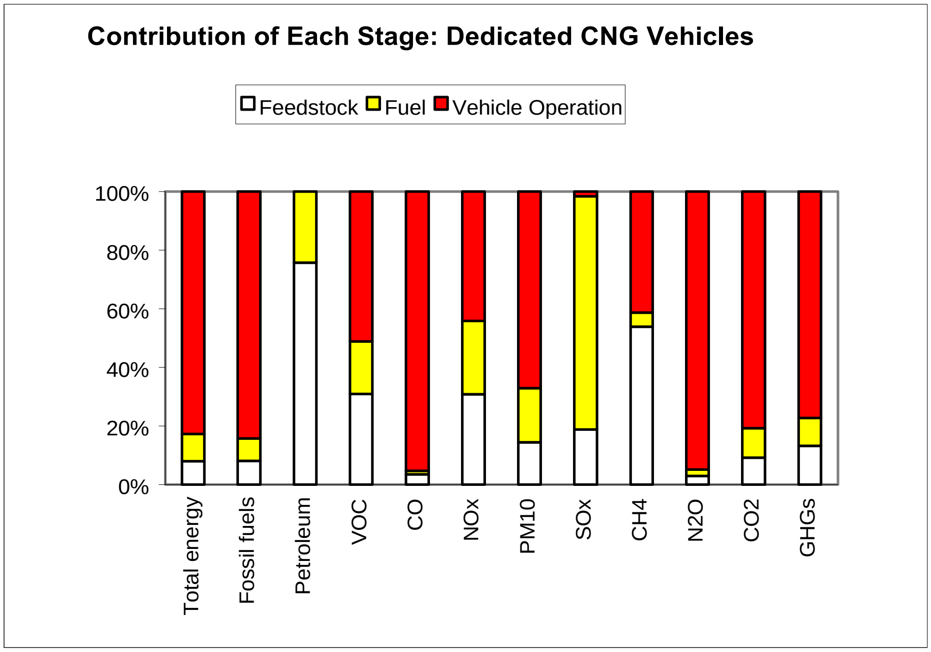

Figure 6.3 Shares of Fuel-Cycle Energy Use and Emissions by Stage: Dedicated CNG Vehicles

VOC emissions. A similar pattern of stage contributions exists for bi-fuel CNG vehicles burning NG.

Figure 6.4 presents results from methanol FFVs fueled with M85. Upstream NG recovery and processing produce most of the total fuel-cycle CH_4 emissions. Methanol production at methanol plants accounts for the largest share of the total SO_x emissions. Methanol production accounts for a noticeable portion of the total energy use, fossil fuel use, and emissions of NO_x, PM_{10}, VOC, CO_2, and GHGs.

Figure 6.5 presents shares of stages for LPG vehicles. In GREET 1.5, production of LPG is simulated with two pathways: crude and NG to LPG. On average, the United States produces 60% of its LPG from NG and 40% from crude. The results in Figure 6.5 are for this combination of production. As the figure shows, upstream activities contribute to all the SO_x emissions. Crude recovery and NG recovery and processing contribute most to the total CH_4 emissions.

Figure 6.6 shows results for ethanol FFVs fueled with E85, where ethanol is produced from corn. Ethanol can be produced in either dry or wet milling plants. The results in this figure are for a combination of both, with two-thirds of the ethanol produced from wet milling plants and one-third from dry milling plants. Except for total energy use, petroleum use, and emissions of CO and VOC, upstream activities account for most of the total fossil energy use and

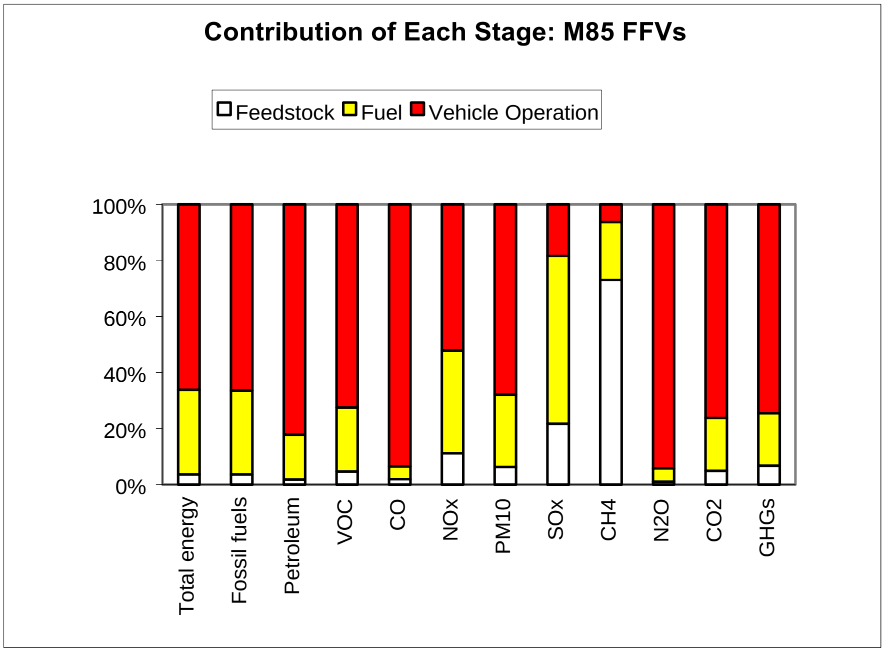

Figure 6.4 Shares of Fuel-Cycle Energy Use and Emissions by Stage: Methanol FFVs Fueled with M85

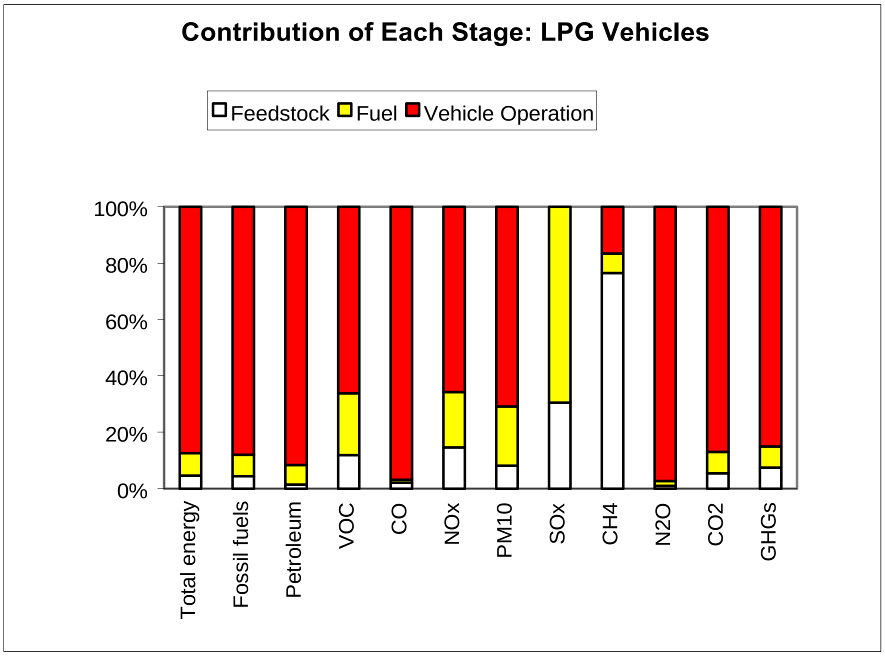

Figure 6.5 Shares of Fuel-Cycle Energy Use and Emissions by Stage: LPG Vehicles

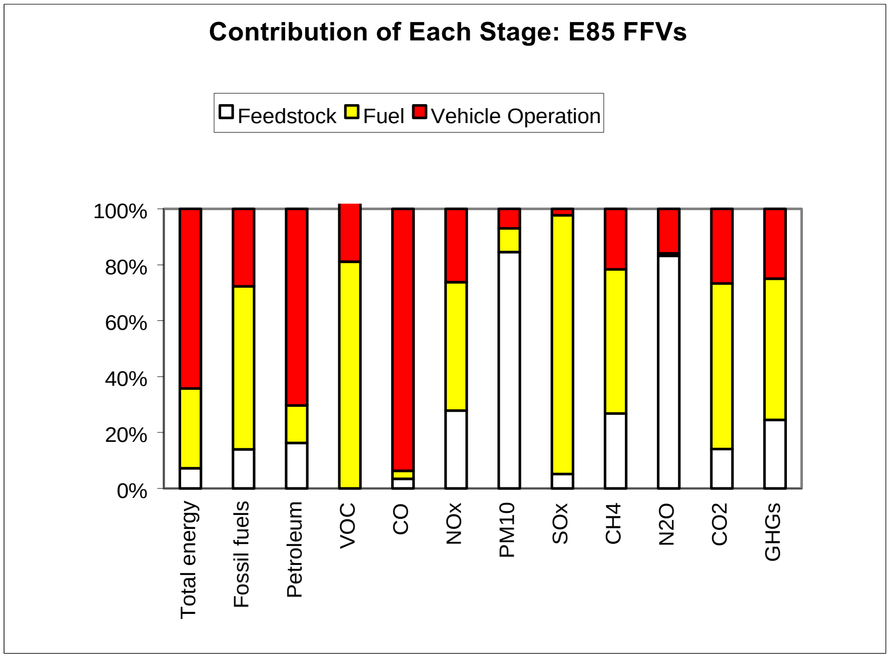

Figure 6.6 Shares of Fuel-Cycle Energy Use and Emissions by Stage: Ethanol FFVs Fueled with E85 Produced from Corn

emissions. This indicates that assumptions about upstream activities have large effects on fuel-cycle results for ethanol FFVs. Because of nitrification and denitrification of nitrogen fertilizer, corn farming contributes the most to the total N_2O emissions. Ethanol production at corn ethanol plants consumes a large amount of fossil fuels and produces large amounts of PM_{10}, VOC, NO_x, SO_x, CH_4, CO_2, and GHG emissions. PM emissions from corn farming (mainly tillage emissions and farming tractor emissions) account for the largest share of fuel-cycle PM emissions.

Figure 6.7 shows the results for EVs. The results are for the U.S. generation mix, under which 54% of electricity is generated from coal. Energy use and emissions occur during upstream stages, except for PM_{10}, where EV brake- and tire-wear emissions are noticeable. Furthermore, among the upstream activities, energy use and emissions occur mostly during electricity generation. Methane emissions occur primarily during coal mining and NG recovery and processing. Also, a large amount of VOC and CO emissions and petroleum use occur during coal mining and NG recovery and processing.

Figure 6.8 presents the results for grid-connected HEVs, where ICEs are fueled with California RFG2. In our study, we assume that for grid-connected HEVs, grid electricity powers 30% of their VMT, with on-board ICEs providing energy for the remaining 70%. Except for petroleum use and emissions of VOC, CO and N_2O, energy use and emissions occur more during upstream stages (especially during fuel production stages) than during the vehicle operation stage.

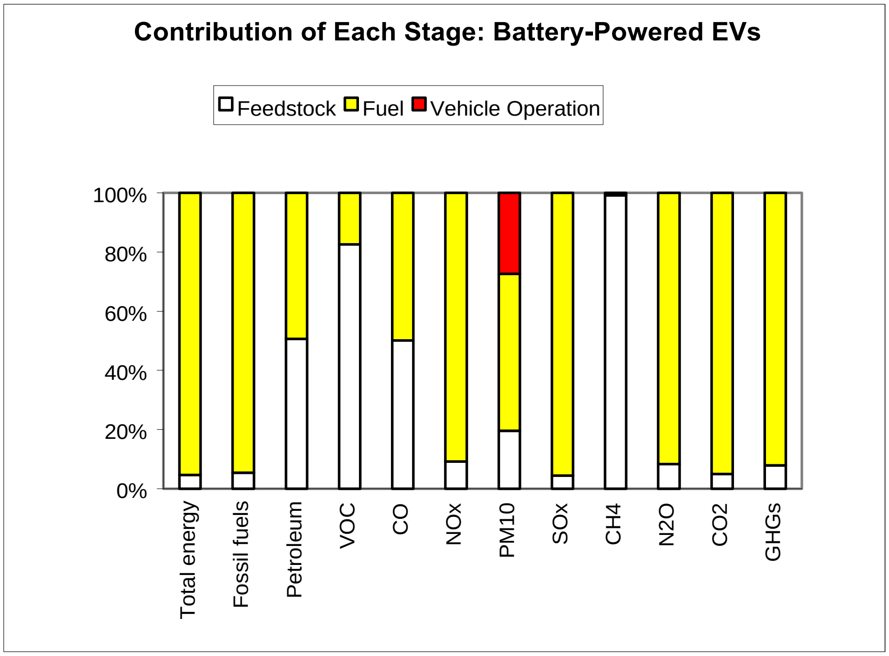

Figure 6.7 Shares of Fuel-Cycle Energy Use and Emissions by Stage: Battery-Powered EVs

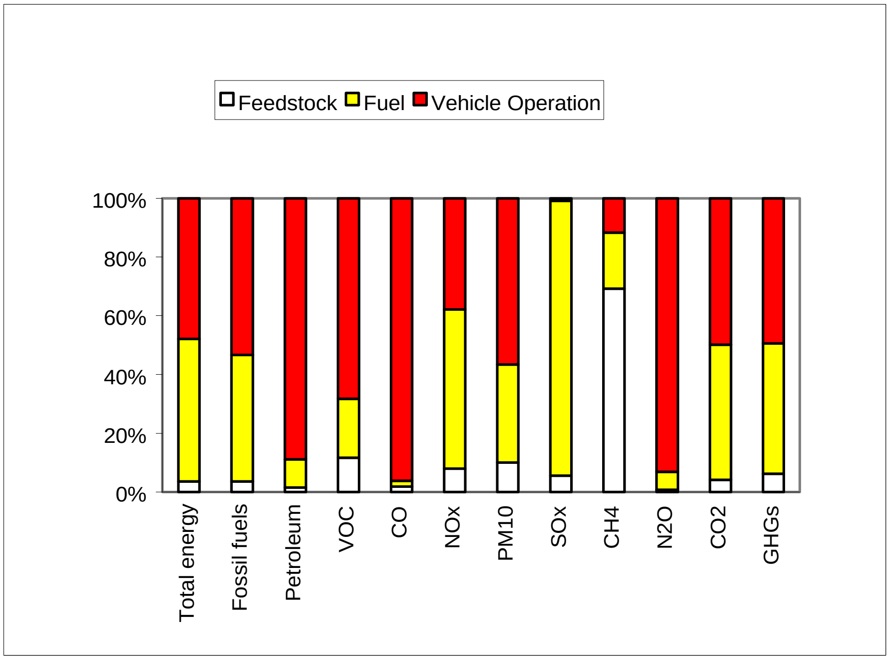

Figure 6.8 Shares of Fuel-Cycle Energy Use and Emissions by Stage: Grid-Connected HEVs, ICEs Fueled with RFG

Figures 6.9 and 6.10 present stage contributions for grid-independent HEVs fueled with RFG and CD. Petroleum refining accounts for a large portion of the total SO_x emissions. Petroleum recovery accounts for a large portion of the total CH_4 emissions. Otherwise, vehicle operations contribute overwhelmingly to total energy use and emissions.

In the above ten figures, stage contributions for the five criteria pollutants are for total emissions. Stage contributions for urban emissions of the five pollutants are different from those for total emissions. Even though upstream contributions to total emissions are large for a given vehicle technology, the upstream contributions could be very small because most upstream activities (and upstream emissions) occur outside of an urban area.

6.3.2 Long-Term Technologies

This section presents the results for those long-term technology options that are very different from the near-term options. Technology options similar to the near-term options are presented in Section 6.3.1. In particular, stage contributions for ICE vehicles fueled with CNG and LNG are similar to those for near-term dedicated CNGVs (Figure 6.3), although as vehicle fuel economy increases among vehicle technologies, upstream contributions become smaller. Stage contributions for ICE vehicles fueled with M90 are similar to those for the near-term M85 FFVs (Figure 6.4). Stage contributions for ICE vehicles fueled with E90 are similar to those for the near-term E85 FFVs (Figure 6.6).

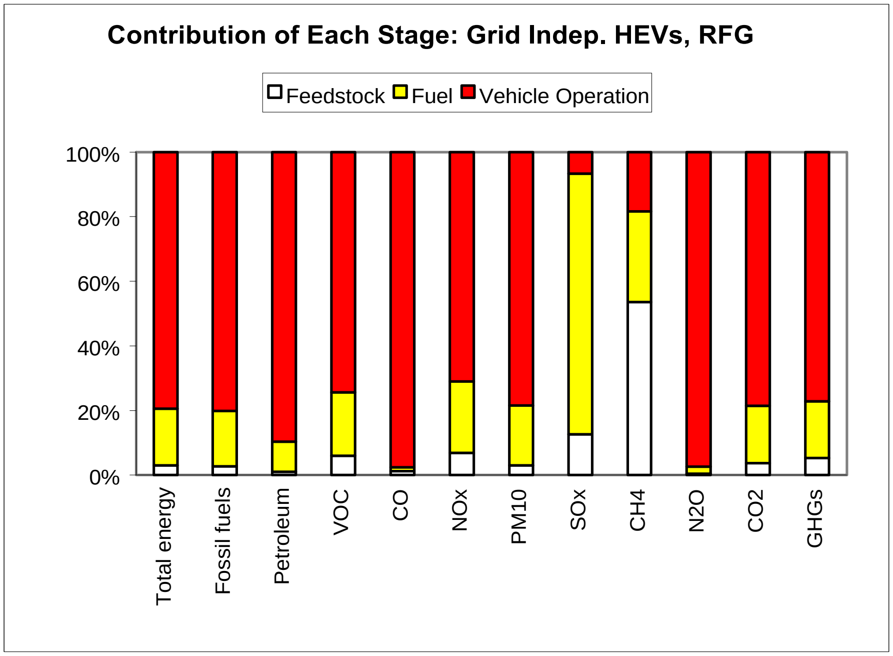

Figure 6.9 Shares of Fuel-Cycle Energy Use and Emissions by Stage: Grid-Independent HEVs, ICEs Fueled with RFG

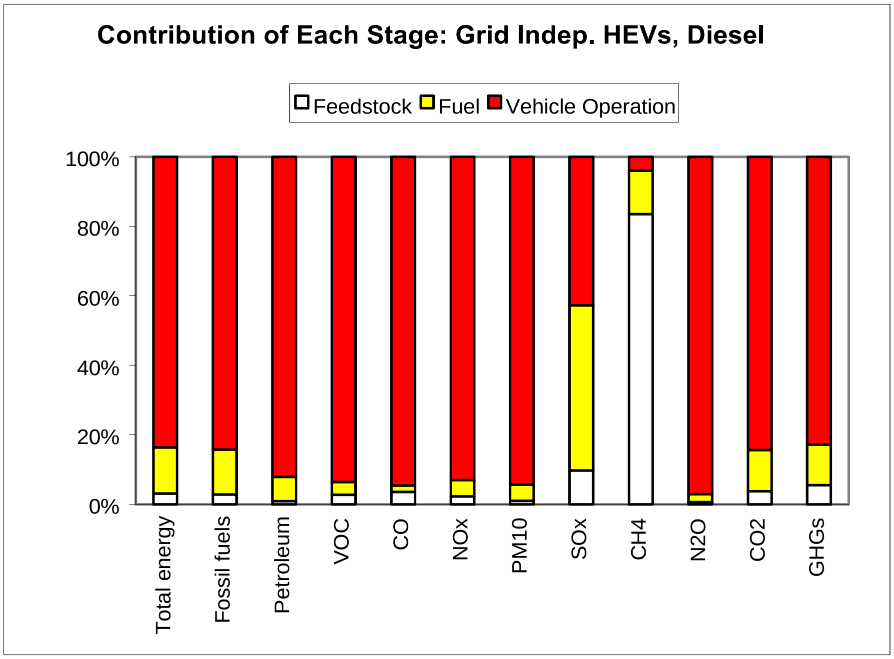

Figure 6.10 Shares of Fuel-Cycle Energy Use and Emissions by Stage: Grid-Independent HEVs, ICEs Fueled with CD

Figures 6.11 and 6.12 show the results for CIDI vehicles fueled with FT50 and BD20. Because diesel is used in blending with both FTD (50%) and biodiesel (80%), the results for the two blends are similar. Except for emissions of SO_x, CH_4, and NO_x vehicle operations contribute mostly to the total energy use and emissions. For SO_x emissions, production of fuels (diesel, FTD, and biodiesel) contributes significantly to the total fuel-cycle emissions. Petroleum recovery and NG recovery and processing (for FTD) produce the greater portion of the total CH_4 emissions. Fuel production contributes to a large share of total NO_x emissions. With BD20, a large amount of VOC emissions are generated during biodiesel production (mainly because of n-hexane loss during soy oil extraction).

Figure 6.13 shows that for CIDI vehicles fueled with DME, upstream activities account for all the petroleum use and SO_x emissions as well as a greater portion of total CH_4 emissions. Furthermore, petroleum use emissions are primarily from DME production; CH_4 emissions are primarily from NG recovery and processing, and SO_x emissions are from both NG recovery and DME production. For other energy use and emissions, vehicle operations account for a large portion. Note that upstream activities contribute a significant portion to total energy use, fossil energy use, and emissions of NO_x, VOC, CO_2, and GHGs.

Figure 6.14 shows the results for grid-connected HEVs, where on-board ICEs are fueled with CNG. Except for CO emissions, energy use and emissions occur primarily during upstream stages. Furthermore, feedstock production accounts for the greater part of upstream

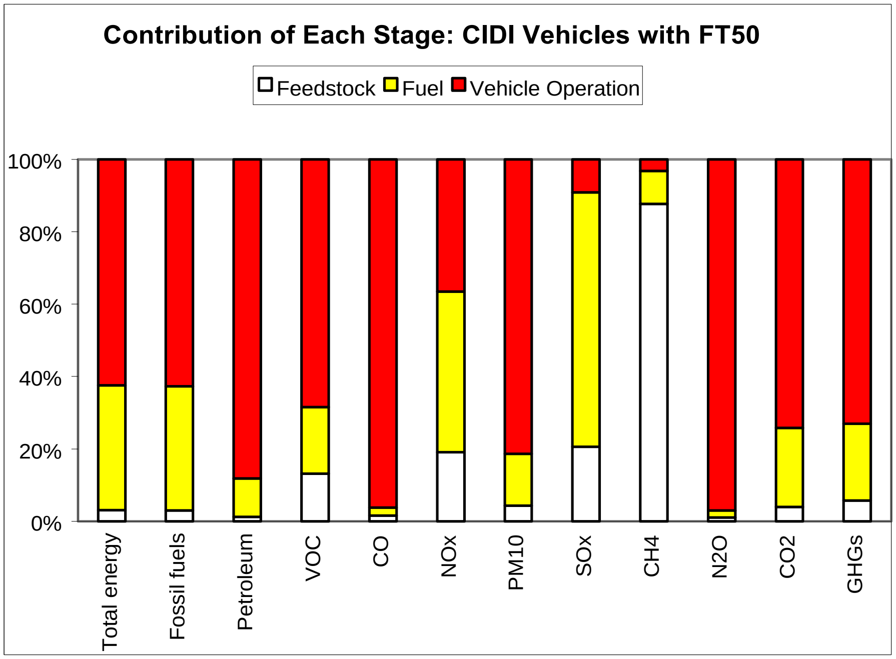

Figure 6.11 Shares of Fuel-Cycle Energy Use and Emissions by Stage: CIDI Vehicles Fueled with FT50

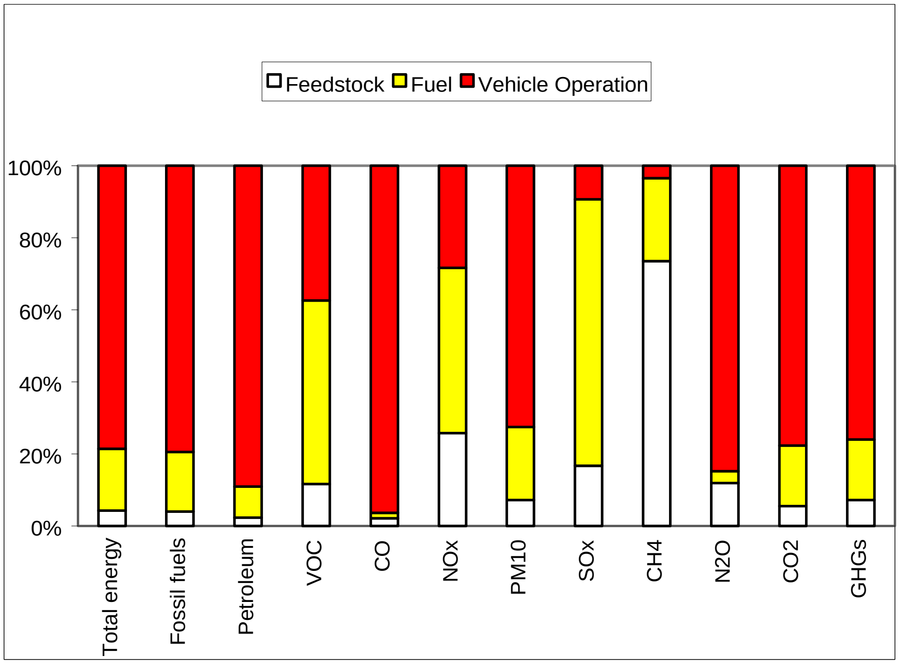

Figure 6.12 Shares of Fuel-Cycle Energy Use and Emissions by Stage: CIDI Vehicles Fueled with BD20

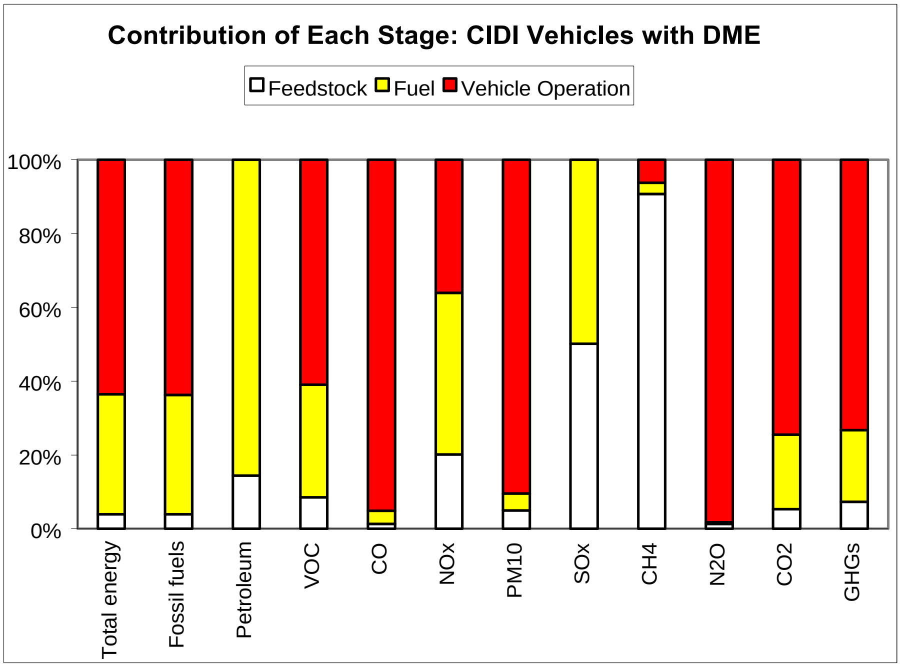

Figure 6.13 Shares of Fuel-Cycle Energy Use and Emissions by Stage: CIDI Vehicles Fueled with DME

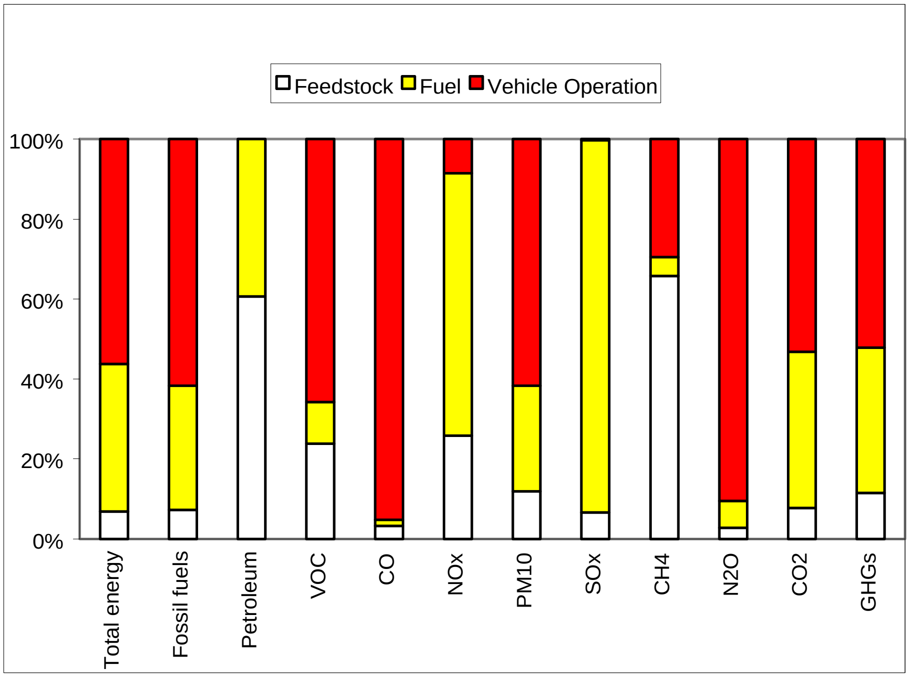

Figure 6.14 Shares of Fuel-Cycle Energy Use and Emissions by Stage: Grid-Connected HEVs, ICEs Fueled with CNG

petroleum use and CH_4 emissions. For other energy use and emissions, fuel production (i.e., electricity generation and NG compression) contributes the most.

Figure 6.15 presents stage contributions for grid-independent HEVs fueled with NG. The general pattern for the HEVs is similar to that for the grid-connected HEV with ICE operation fueled with NG. With the former, however, the contribution from vehicle operations is increased.

Figure 6.16 presents the results for FCVs fueled with gaseous H_2 produced from NG. Except for total energy, fossil energy, and PM_{10} emissions, energy use and emissions occur during upstream stages. Vehicular PM_{10} emissions are from tire and brake wear. Most upstream petroleum use and emissions occur during H_2 production. The exception is CH_4 and petroleum use, where NG recovery and processing account for a large portion of the total CH_4 emissions and petroleum use.

As for FCVs fueled with H_2 produced from solar energy, Figure 6.17 shows that energy use and emissions are from transportation and compression of gaseous hydrogen, except for total energy use and PM_{10} emissions, where vehicle operations also contribute. As Figures 6.16 and 6.17 show, FCVs fueled by H_2, like EVs (Figure 6.7), generate no tailpipe emissions.

Figure 6.18 presents the results for FCVs fueled with NG-based methanol. NG recovery and processing accounts for the greater portion of the total CH_4 emissions. Methanol production at methanol plants consumes a large amount of petroleum and produces a large amount of NO_x and SO_x emissions. Vehicle operations contribute significantly to the total energy use, fossil energy use, and emissions of VOCs, CO, PM_{10} (from brake and tire wear), N_2O, CO_2, and GHGs.

Figure 6.19 shows that for FCVs fueled with RFG, crude recovery accounts for the greater portion of the total CH_4 emissions. Petroleum refining accounts for a large amount of the total emissions for NO_x and SO_x. Vehicle operations contribute most to the total energy use, fossil energy use, petroleum use, and emissions of VOCs, CO, PM_{10}, N_2O, $CO_{2,}$ and GHGs.

Figure 6.20 shows stage contributions for FCVs fueled with ethanol produced from corn. Except for total energy use and CO emissions, upstream stages contribute most of the energy use and emissions. Between corn farming and ethanol production, ethanol production contributes mainly to fossil energy use and emissions of VOCs, NO_x, SO_x, CH_4, CO_2, and GHGs. Corn farming contributes mainly to petroleum use and emissions of PM_{10} and N_2O.

Figure 6.21 presents the results for CNG-fueled FCVs. NG recovery, processing, and transmission contribute significantly to petroleum use and emissions of NO_x and CH_4. NG compression produces a large amount of emissions of NO_x and SO_x. Vehicle operations consume the greater portion of the total energy and fossil energy and produce most of the CO, N_2O, PM_{10}, CO_2, and GHG emissions.

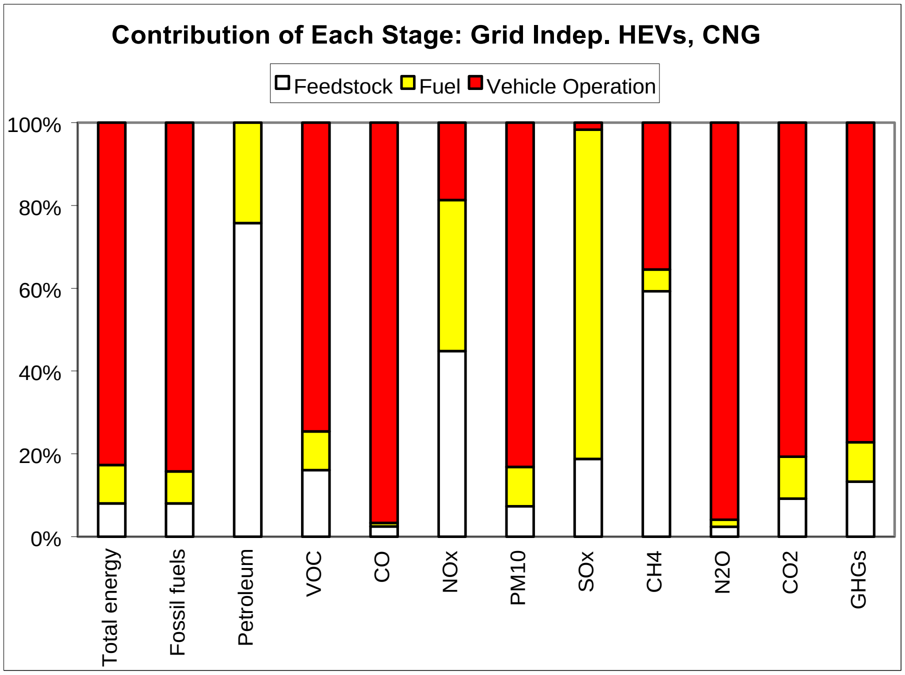

Figure 6.15 Shares of Fuel-Cycle Energy Use and Emissions by Stage: Grid-Independent HEVs, ICEs Fueled with NG

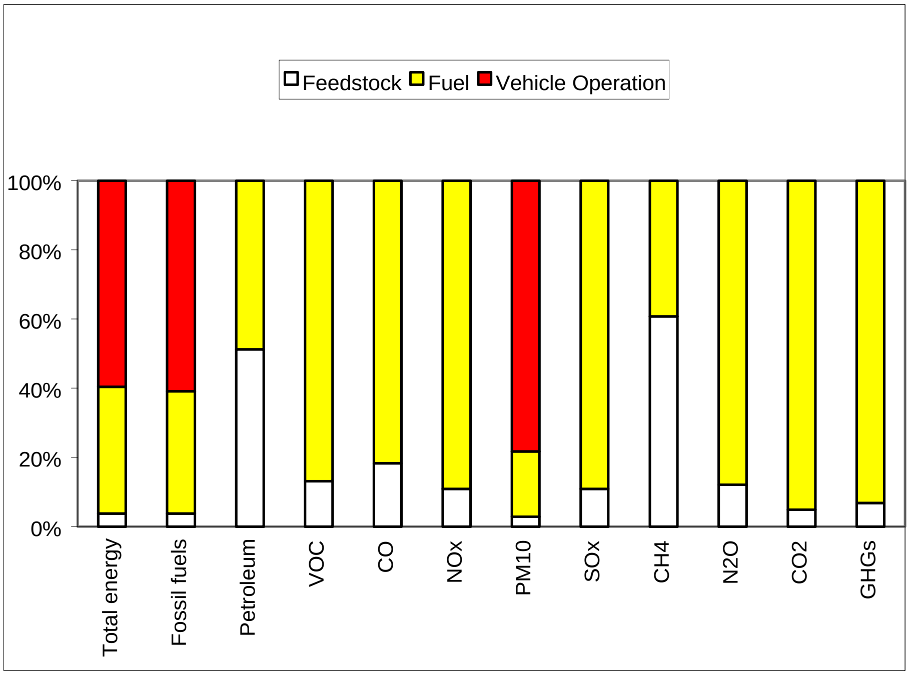

Figure 6.16 Shares of Fuel-Cycle Energy Use and Emissions by Stage: FCVs Fueled with H_2 Produced from NG

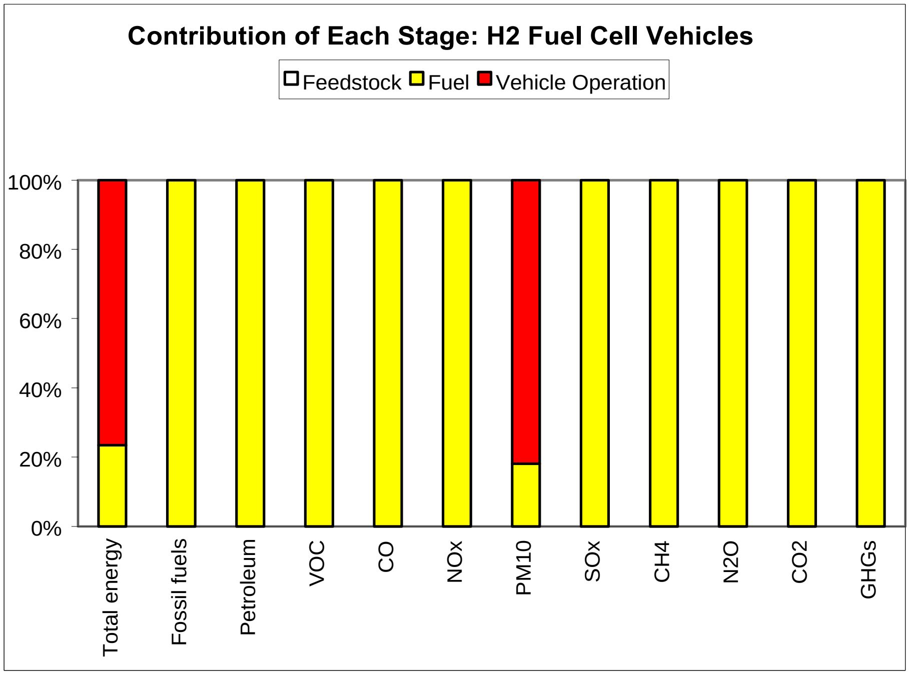

Figure 6.17 Shares of Fuel-Cycle Energy Use and Emissions by Stage: FCVs Fueled with H_2 from Solar Energy

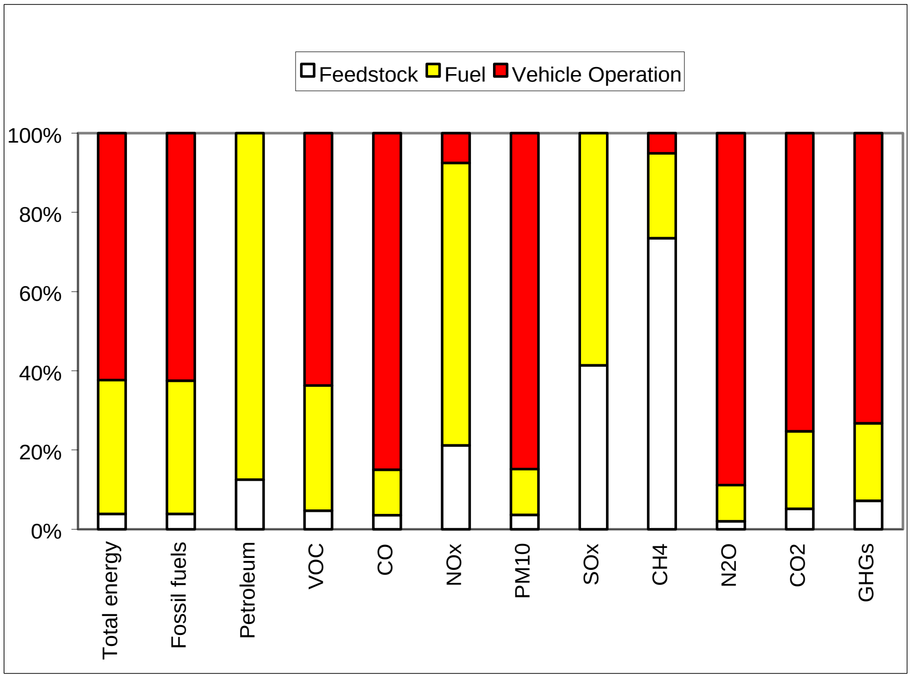

Figure 6.18 Shares of Fuel-Cycle Energy Use and Emissions by Stage: FCVs Fueled with Methanol

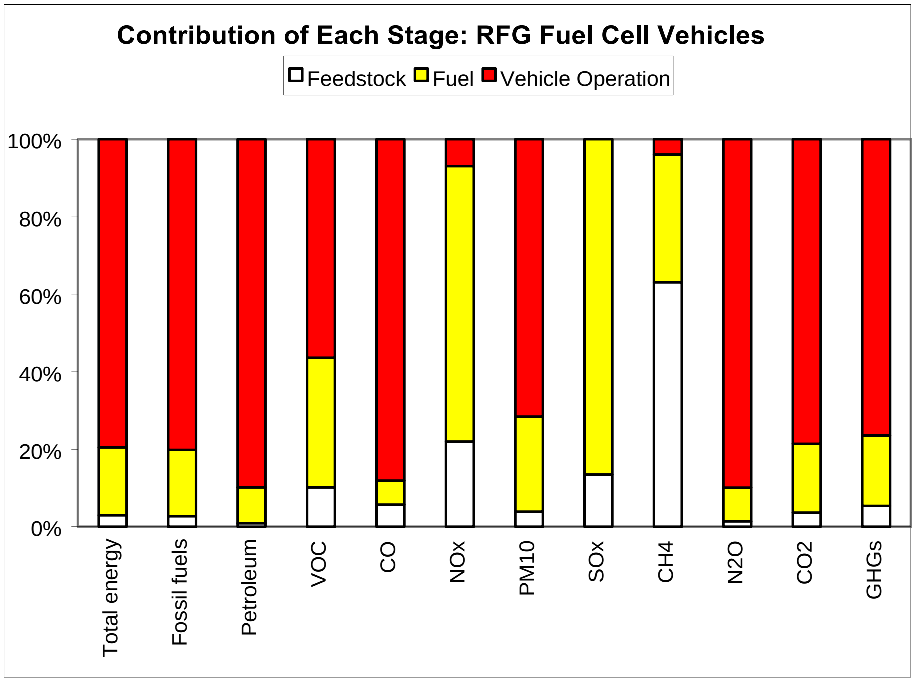

Figure 6.19 Shares of Fuel-Cycle Energy Use and Emissions by Stage: FCVs Fueled with RFG

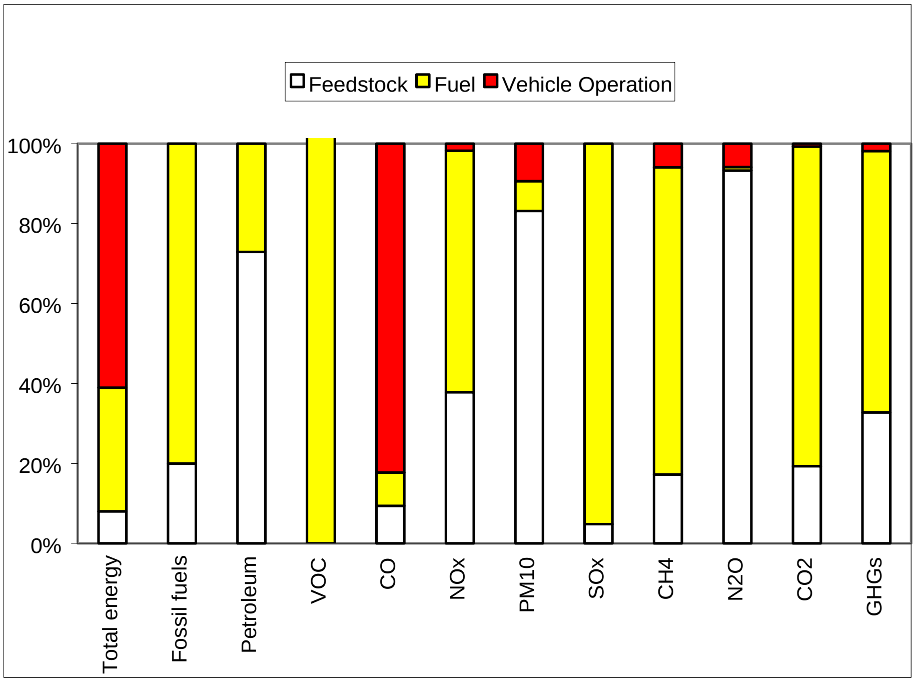

Figure 6.20 Shares of Fuel-Cycle Energy Use and Emissions by Stage: FCVs Fueled with Ethanol

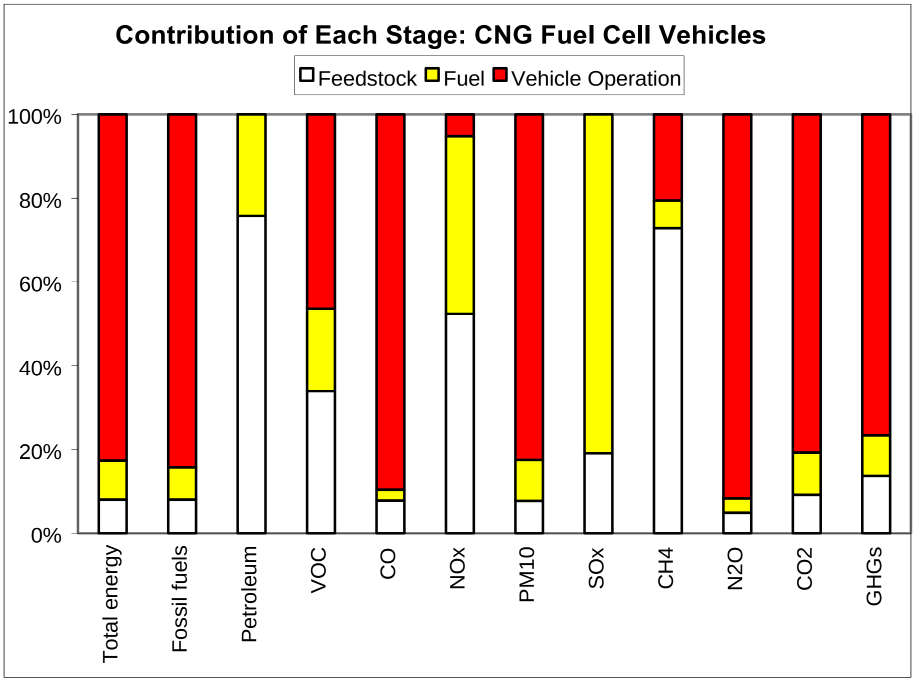

Figure 6.21 Shares of Fuel-Cycle Energy Use and Emissions by Stage: FCVs Fueled with CNG

Stage contribution results for cellulosic-ethanol-fueled vehicles (dedicated ethanol vehicles and FCVs) are not presented, because those results are distorted by energy and emission credits for the electricity generated at cellulosic ethanol plants. If energy and emission credits for the generated electricity were not considered, upstream biomass farming and cellulosic ethanol production would contribute significantly to total fuel-cycle energy use and emissions.

6.4 Per-Mile Energy Use and Emissions Results

In this section, we present per-mile, fuel-cycle energy use and emission results for the near- and long-term technologies included in GREET 1.5. Calculated per-mile energy use and emissions for three light-duty vehicle types — passenger cars, LDT1, and LDT2 — are presented in Appendix B. Changes in per-mile energy use and emissions associated with alternative fuels and advanced transportation technologies relative to baseline GVs are presented in this section.

Among the three light-duty vehicle types, the absolute amounts of fuel-cycle energy use (in Btu/mi) and emissions (in g/mi) increase in the following order: passenger cars, LDT1, and LDT2. For alternative transportation technologies, even if the relative changes in energy use and emissions are similar among the three types, the changes in absolute amounts will be different. In particular, application of a given technology to LDT2 will result in greater changes in per-mile energy use and emissions than its application to LDT1, and application to LDT1 will result in greater changes than its application to passenger cars. Users can employ the per-mile energy and emission results presented in Appendix B to determine the absolute energy and emission benefits per mile driven.

The relative changes by a given alternative fuel or an advanced transportation technology certainly differ among the three light-duty vehicle types, although the differences between passenger cars and LDT1 are generally smaller (because the same relative fuel economy and emission changes for vehicle operations are assumed for these two types; see Table 4.35). Our discussion of the relative changes in fuel-cycle energy use and emissions is based on the results for passenger cars, and the figures presented in the sections below are for passenger cars. Similar figures giving relative changes for LDT1 and LDT2 are presented in Appendix C. Numerical values of relative changes for passenger cars, LDT1, and LDT2 are presented in Appendix D.

6.4.1 Near-Term Technologies

The next nine figures show changes in fuel-cycle energy use and emissions of various near-term alternative fuels and transportation technologies relative to conventional GVs fueled with CG. Figure 6.22 shows changes in fuel-cycle total energy use. Use of ethanol, methanol, CNG, FRFG2, or CARFG2 in conventional SI engines causes increases in total energy use. The increases associated with M85 and E85 are above 15% and 20%, respectively. The increases are caused primarily by the significant amount of energy consumed during ethanol and methanol production. The increases associated with CNG are caused by CNGV fuel economy penalties. Use of EVs, HEVs, or CIDI engines fueled with diesel results in decreased fuel-cycle total energy use. The decreases are caused mainly by the high energy efficiencies of these vehicle technologies.

Figure 6.23 presents changes in fuel-cycle total fossil energy use for each fuel or vehicle type. Fossil fuels here include petroleum, NG, and coal. Use of M85 in methanol FFVs results in an increase of about 15% in per-mile fossil energy use, which is caused primarily by the large amount of NG used in methanol production at methanol plants. Use of CNG results in small increases in per-mile fossil energy use. Large fossil energy reductions occur with E85 and with diesel in CIDI engines, EVs, or HEVs. The large reduction with E85 occurs because ethanol is a nonfossil fuel; large reductions for CIDI vehicles, EVs, and HEVs are attributable to their high energy efficiencies. Use of LPG also results in reductions.

Figure 6.24 shows petroleum displacement by fuel and vehicle technology. As expected, use of non-petroleum-based fuels reduces petroleum use substantially. Among the vehicle technologies that use petroleum-based fuels, grid-connected and grid-independent HEVs and CIDI vehicles reduce petroleum use by more than 50% because of their efficiency gains. Use of RFG results in a small decrease in petroleum use because the MTBE and ETBE used in RFG are not petroleum based. The limited reduction by E10 occurs because 90% of the fuel blend is gasoline. The limited reduction by petroleum-based LPG occurs apparently because the fuel is petroleum based. The reduction by diesel CIDIs is attributable to vehicle efficiency gains.

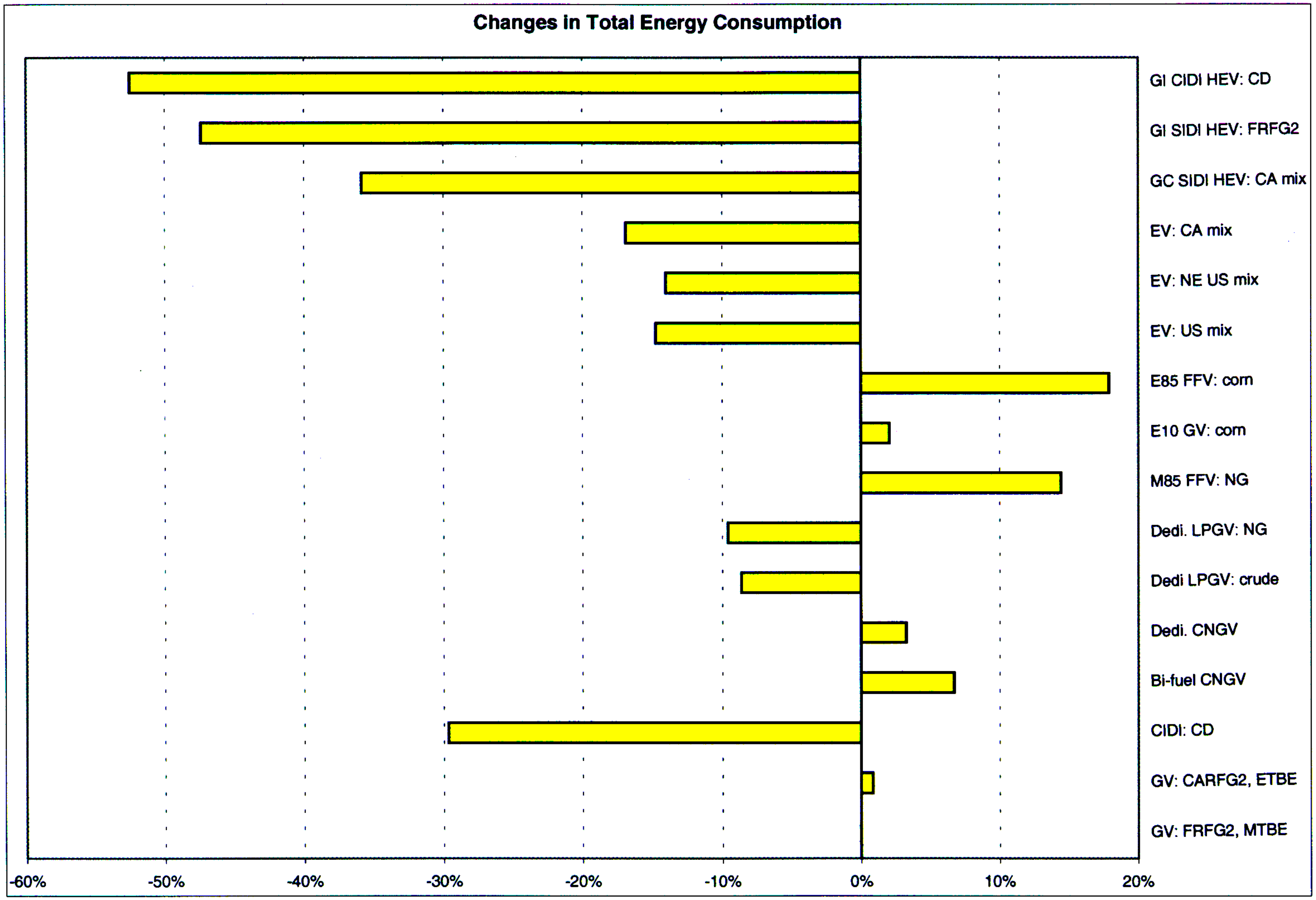

Figure 6.22 Changes in Fuel-Cycle Total Energy Use Relative to GVs Fueled with CG: Near-Term Technologies

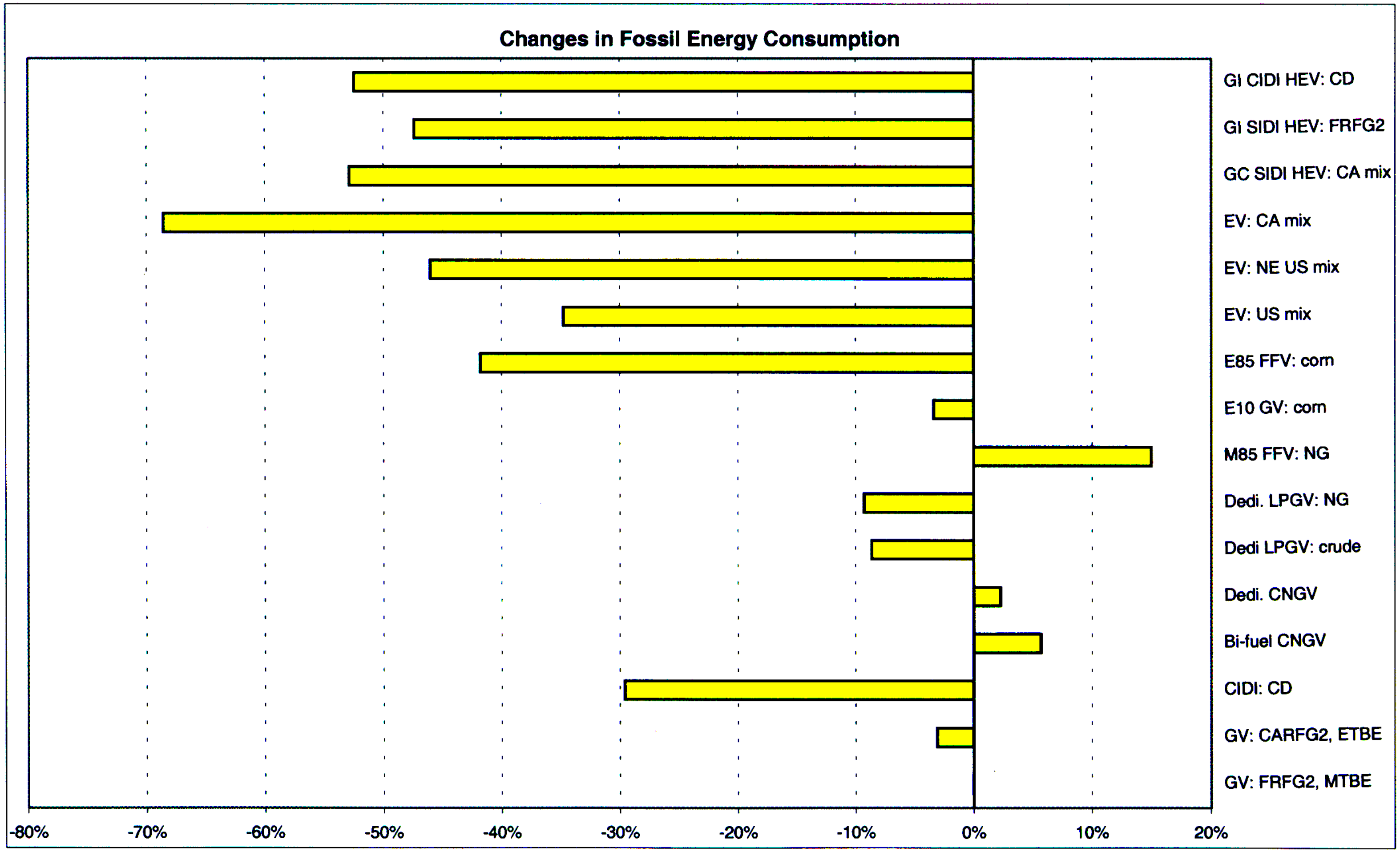

Figure 6.23 Changes in Fuel-Cycle Fossil Energy Use Relative to GVs Fueled with CG: Near-Term Technologies

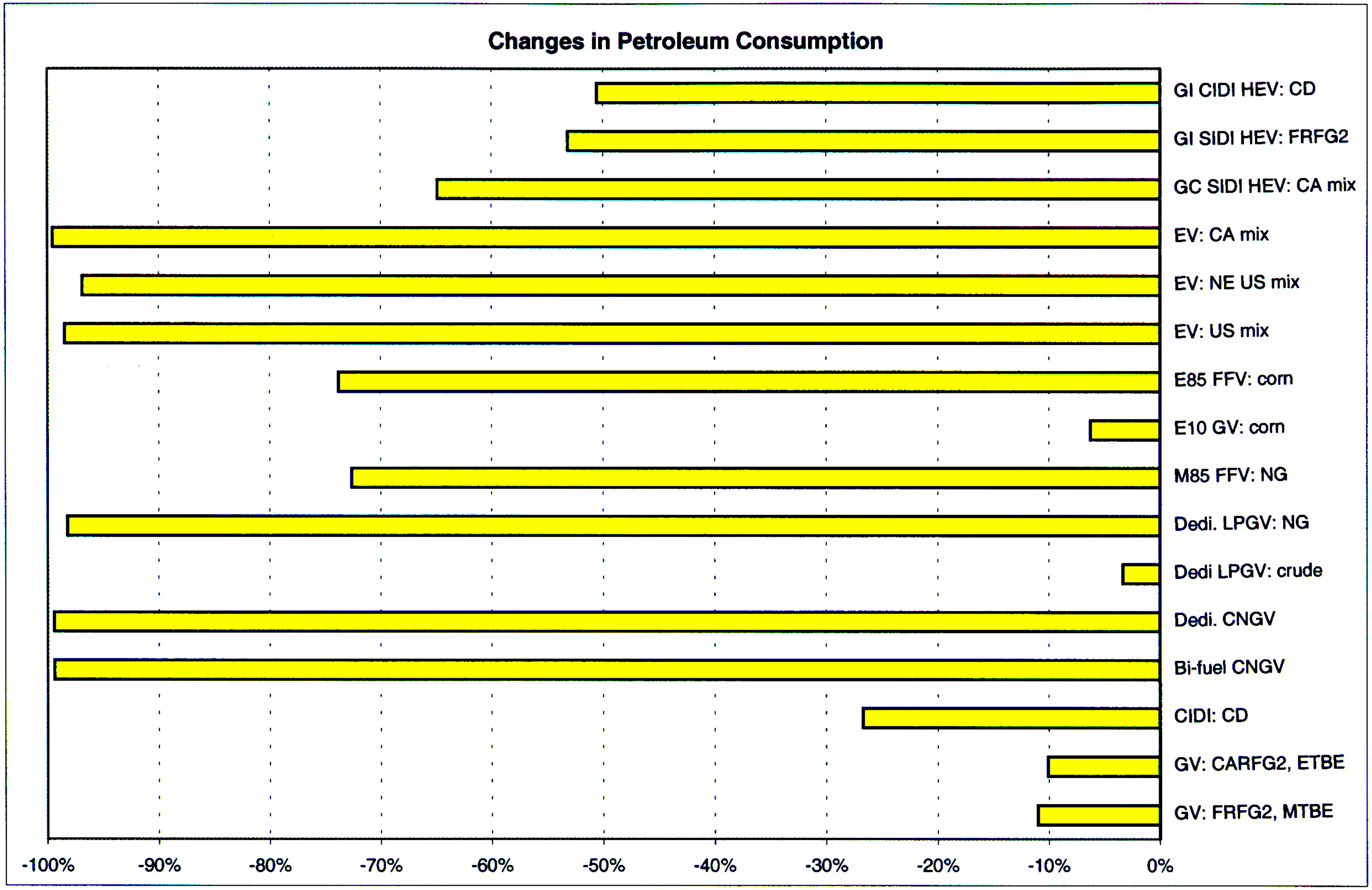

Figure 6.24 Changes in Fuel-Cycle Petroleum Use Relative to GVs Fueled with CG: Near-Term Technologies

Figure 6.25 shows changes in emissions of CO_2 and CO_2-equivalent GHGs. GHG emissions are the sum of emissions of CO_2, CH_4, and N_2O, weighted by their GWPs. Except for use of RFG, where a tiny increase in GHG emissions occurs, use of any fuel or vehicle technology helps reduce GHG emissions. The largest reductions occur for EVs with the California electric generation mix, under which 48% of electricity is produced from hydropower plants. In general, EVs and HEVs reduce GHG emissions by more than 40%, mainly because of their efficiency gains. Significant reductions are also achieved by use of CIDI vehicles and E85 FFVs. The CIDI reduction results from vehicle efficiency gains. The E85 reduction occurs because ethanol is produced from a renewable resource (corn). Even emissions from corn farming and ethanol production are taken into account. Use of LPG and CNG achieves moderate reductions. Use of E10 results in only a small reduction (a few percentage points) because gasoline still accounts for most of E10. The small reduction by M85 FFVs is attributable to methanol production emissions. Use of ETBE in RFG results in a smaller benefit than use of MTBE because ETBE is produced from ethanol.

The reductions in CO_2 and GHG emissions are similar for the combinations of fuels and vehicle technologies considered, except for CNG and E85, which resulted in smaller reductions in GHG emissions than in CO_2 emissions. The smaller GHG emissions reduction by CNGVs is attributable to a large amount of CH_4 emissions during upstream stages of the NG cycle. The smaller reduction by E85 is attributable to a large amount of N_2O emissions during corn farming.

Figure 6.26 presents changes in both total and urban VOC emissions. Use of any fuel or vehicle technology helps reduce fuel-cycle total and urban VOC emissions, except for E10 and E85, both of which produce small increases in VOC emissions (urban VOC emissions are reduced by use of E85). The increase in total VOC emissions with E85 is caused by significant VOC emissions released during ethanol production. High VOC emissions during ethanol production and high VOC evaporative emissions during vehicle operation cause the increases in both total and urban VOC emissions when E10 is used. Use of EVs achieves better than 90% reductions in both total and urban VOC emissions. In fact, use of EVs almost eliminates urban VOC emissions. Use of LPGVs, CNGVs, diesel CIDI, CNGVs, grid-connected HEVs, or diesel HEVs achieves greater-than-40% reductions. Use of RFG or M85 FFVs achieves reductions of about 20%.

Figure 6.27 shows that use of the subject fuels or vehicle technologies helps reduce both total and urban fuel-cycle CO emissions. Because the greater portion of fuel-cycle emissions occurs during vehicle operation for these fuels or technologies (except for EVs), urban CO emissions, where vehicular CO emissions occur, are very close to total CO emissions. Use of EVs and diesel fuels in HEVs or CIDI engines helps reduce CO emissions by more than 80%. Use of CNGVs, LPGVs, methanol FFVs, ethanol FFVs, E10 FFVs, and HEVs results in reductions in CO emissions of around 40%. Use of RFG reduces CO emissions by about 20%.

Figure 6.28 indicates that NO_x emissions can decrease or increase, depending on the fuels or vehicle technologies used. For urban NO_x emissions, diesel engines face the challenge of

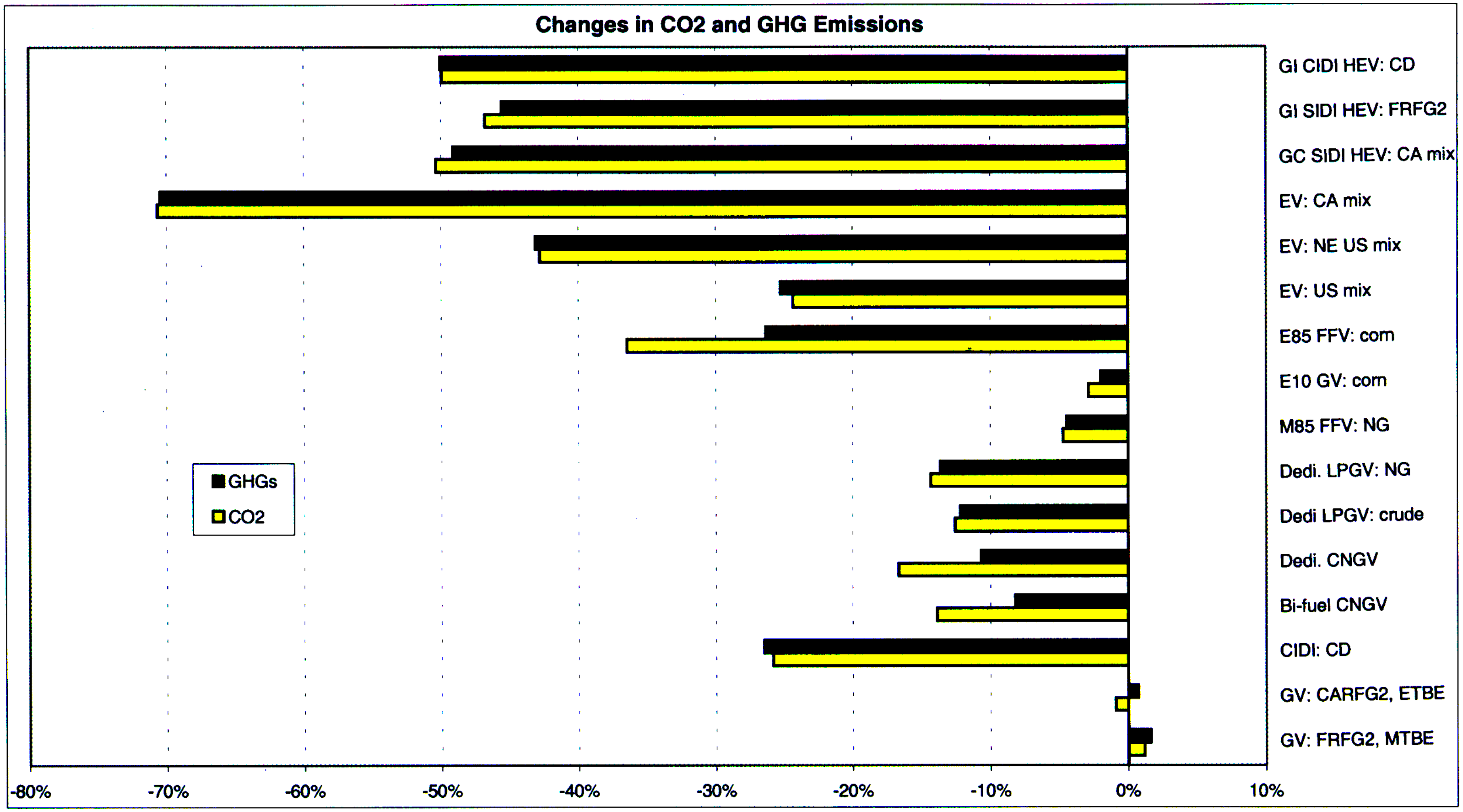

Figure 6.25 Changes in Fuel-Cycle GHG Emissions Relative to GVs Fueled with CG: Near-Term Technologies

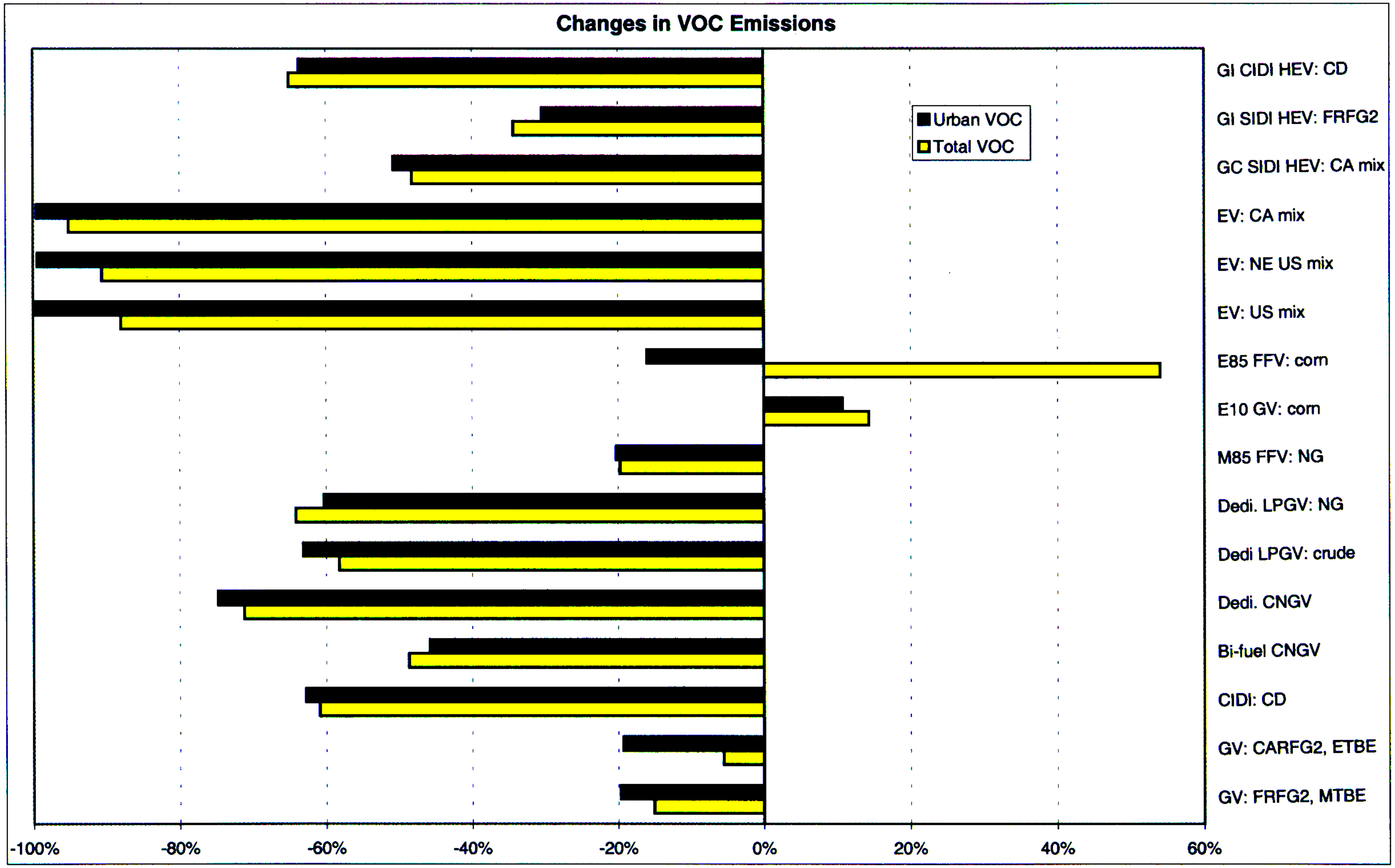

Figure 6.26 Changes in Fuel-Cycle VOC Emissions Relative to GVs Fueled with CG: Near-Term Technologies

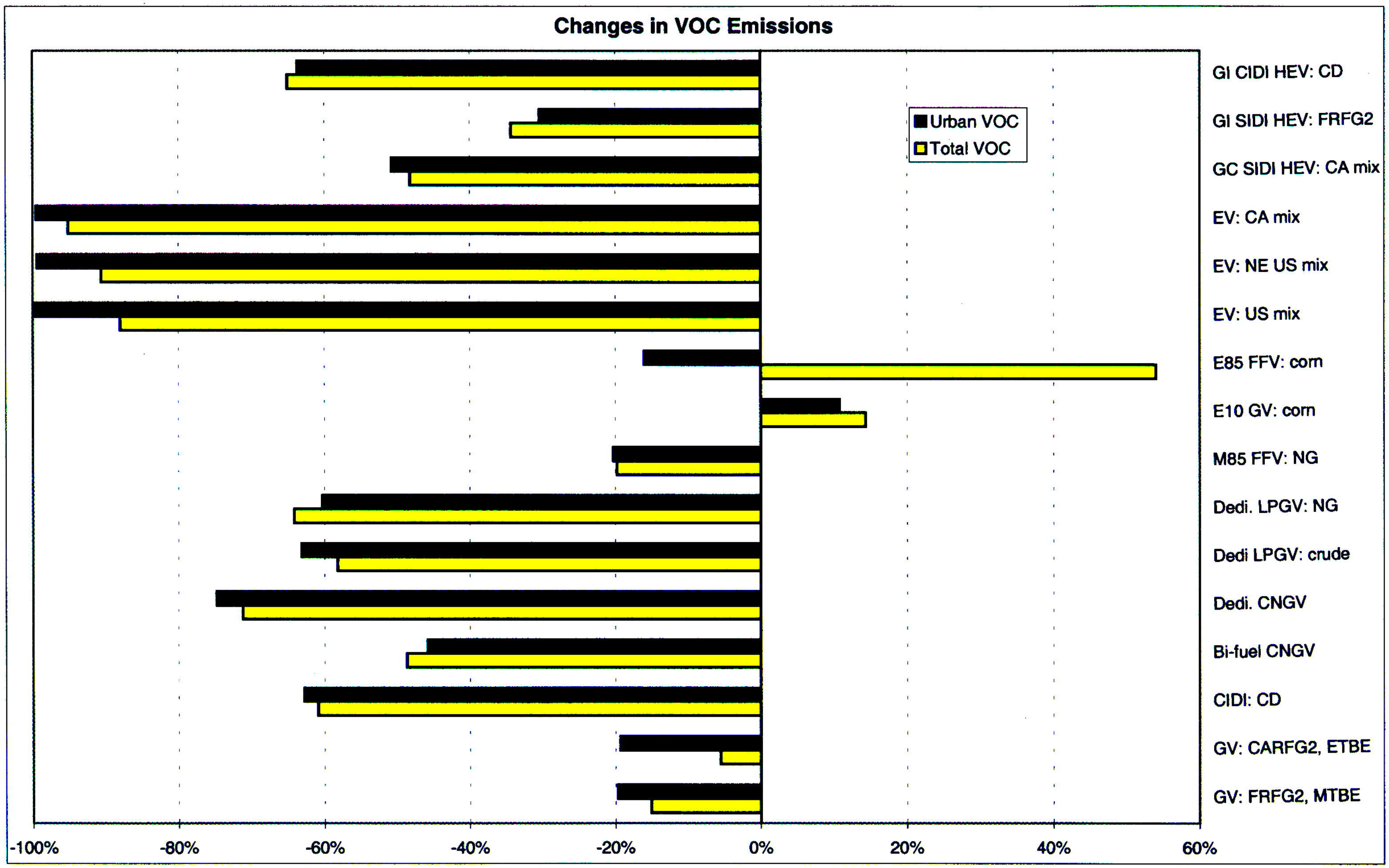

Figure 6.27 Changes in Fuel-Cycle CO Emissions Relative to GVs Fueled with CG: Near-Term Technologies

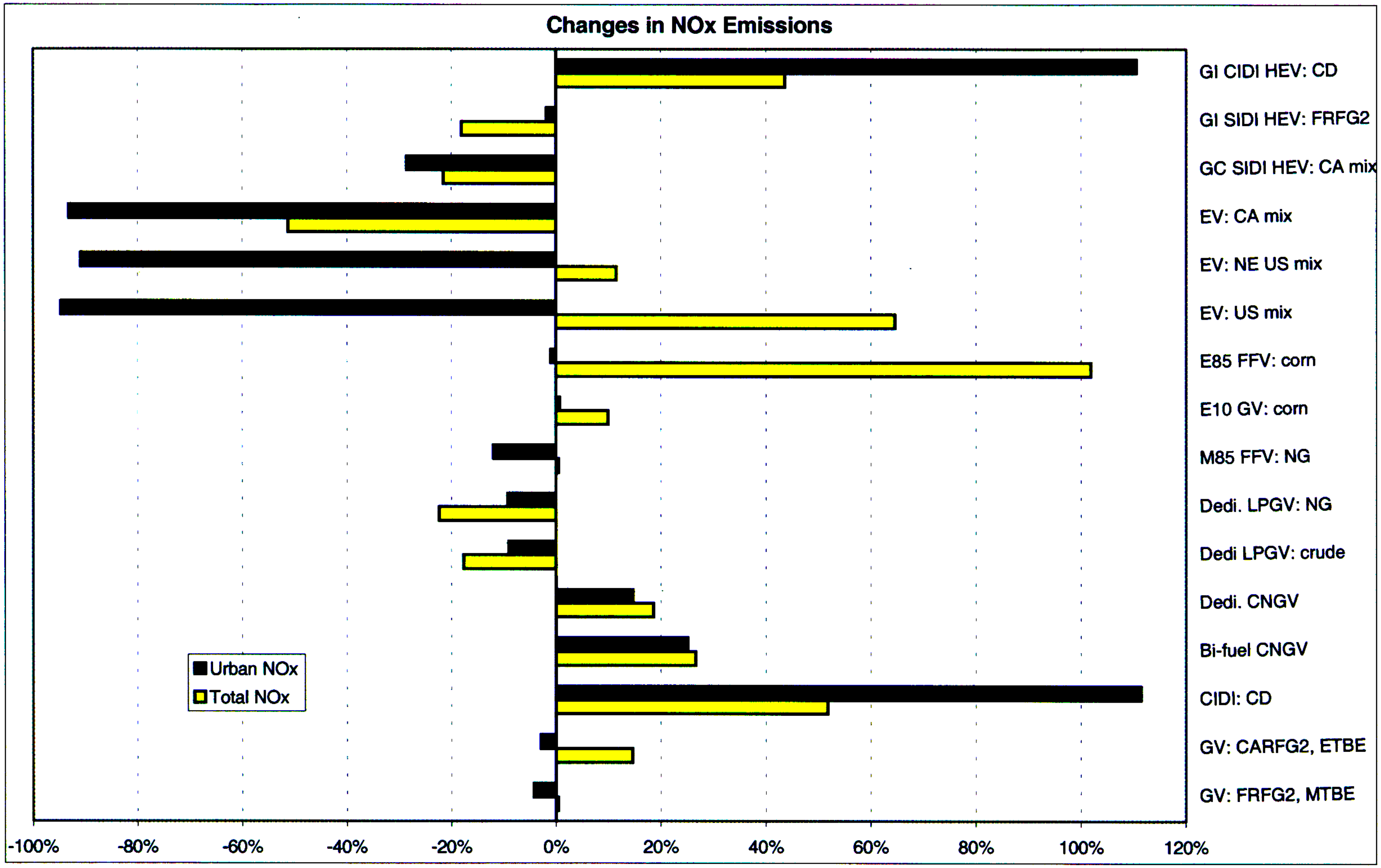

Figure 6.28 Changes in Fuel-Cycle NO$_x$ Emissions Relative to GVs Fueled with CG: Near-Term Technologies

reducing NO_x emissions. Use of diesel fuels in HEVs and CIDI engines may cause over 100% increases in urban NO_x emissions. Use of RFG, M85, LPG, or E10 has little or no effect on NO_x emissions. Use of CNGVs increases both urban and total NO_x emissions, primarily because of the NO_x emissions generated by the compressors used for NG compression. Use of E85 FFVs or LPGVs achieves small reductions in NO_x emissions. Use of EVs reduces urban NO_x emissions by more than 95%. Use of ethanol FFVs and EVs could increase total NO_x emissions.

The increases in total NO_x emissions for E85 and E10 result from the large amount of NO_x emissions released during production of ethanol. The increases in total NO_x emissions from diesel fuels are smaller than the increases in urban NO_x emissions.

Figure 6.29 shows large variations in fuel-cycle PM_{10} emissions. Use of diesel fuels causes increases of about 250% in urban PM_{10} emissions. Use of RFG or E10 has little effect on urban PM_{10} emissions. Use of CNGVs, LPGVs, or EVs achieves moderate reductions (near 40%). The relatively smaller reductions in urban PM_{10} emissions are partly attributable to tire- and brake-wear PM_{10} emissions, which are borne by each vehicle type, diluting the emission reduction effects of fuels and vehicle technologies.

Use of diesel fuels increases total PM_{10} emissions by about 160%. Use of E85 FFVs increases such emissions by six times, because of high upstream PM_{10} emissions during corn farming and ethanol production. Use of E10 or EVs with the U.S. and the U.S. Northeast generation mix results in moderate increases in total PM_{10} emissions. Use of CNGVs, M85 FFVs, LPGVs, EVs, or HEVs with the California generation mix, or of grid-independent HEVs fueled with RFG achieves moderate reductions in total PM_{10} emissions.

Figure 6.30 shows that total SO_x emissions increase with the use of EVs (except with the California generation mix) or ethanol (both E85 and E10). The increase in SO_x emissions by EVs with the U.S. generation mix is 4.5 times. The increases are caused by high SO_x emissions during electricity generation and ethanol production at ethanol plants. Use of other fuels and vehicles results in reductions in total SO_x emissions.

Use of any fuel or vehicle technology reduces urban SO_x emissions, although these reductions are smaller for diesel fuels and E10. For RFG, CNGVs, LPGVs, methanol FFVs, ethanol FFVs, EVs, and HEVs, reductions in urban SO_x emissions are above 80%.

6.4.2 Long-Term Technologies

The next 36 figures show changes in fuel-cycle energy use and emissions for various long-term transportation fuels and advanced technologies relative to conventional GVs fueled with federal RFG2. The long-term technologies are divided into four groups: (1) vehicles equipped with conventional SI engines and SIDI engines fueled with various SI engine fuels; (2) grid-independent (GI) and grid-connected (GC) HEVs equipped with SI engines and SIDI engines powered by various SI engine fuels; (3) vehicles equipped with CIDI engines (including CIDI standalone vehicles), GI HEVs, and GC HEVs; and 4) EVs and FCVs. Because there are over 75 combinations of fuels and vehicle technologies for the long-term options, we created a chart

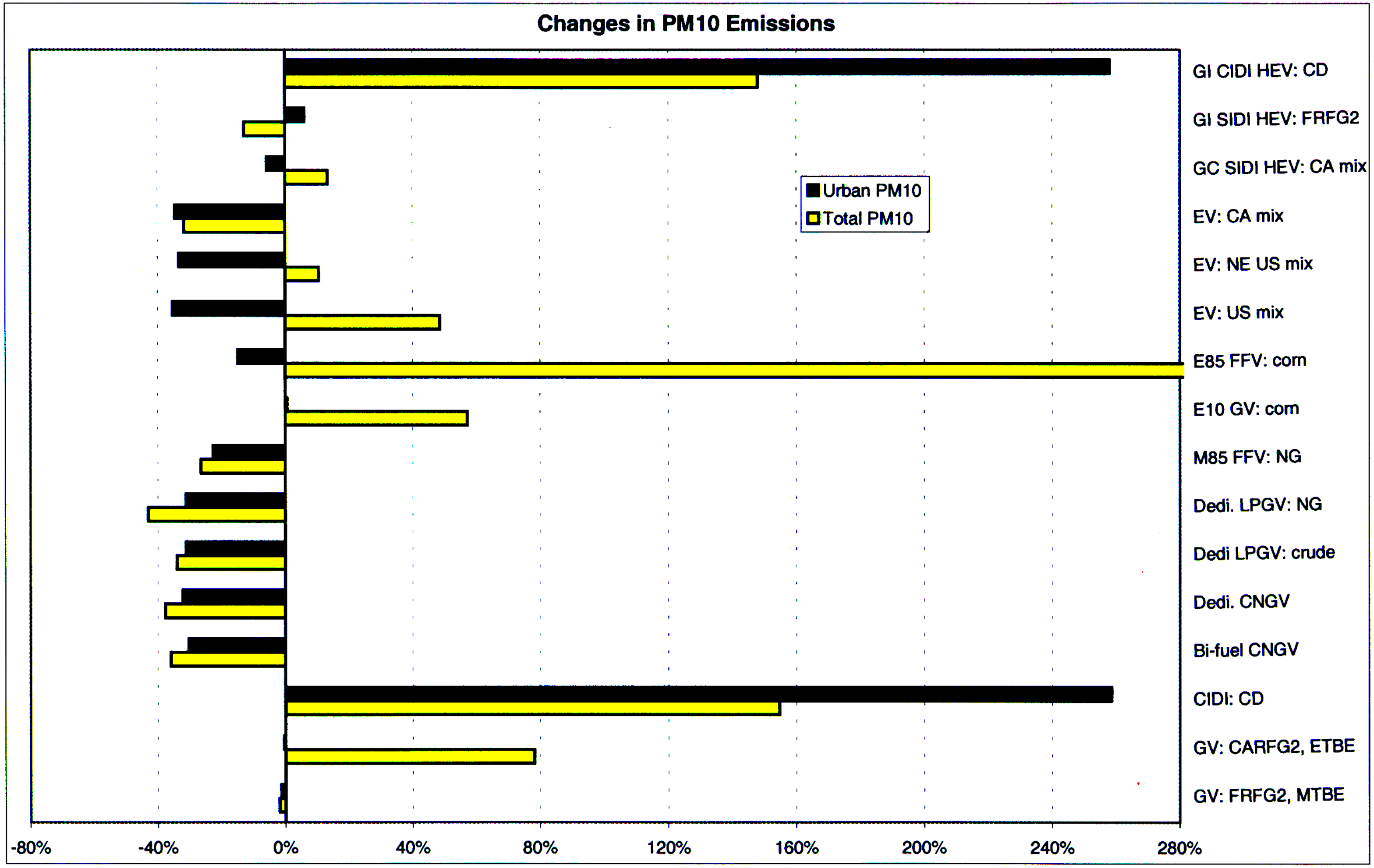

Figure 6.29 Changes in Fuel-Cycle PM_{10} Emissions Relative to GVs Fueled with CG: Near-Term Technologies

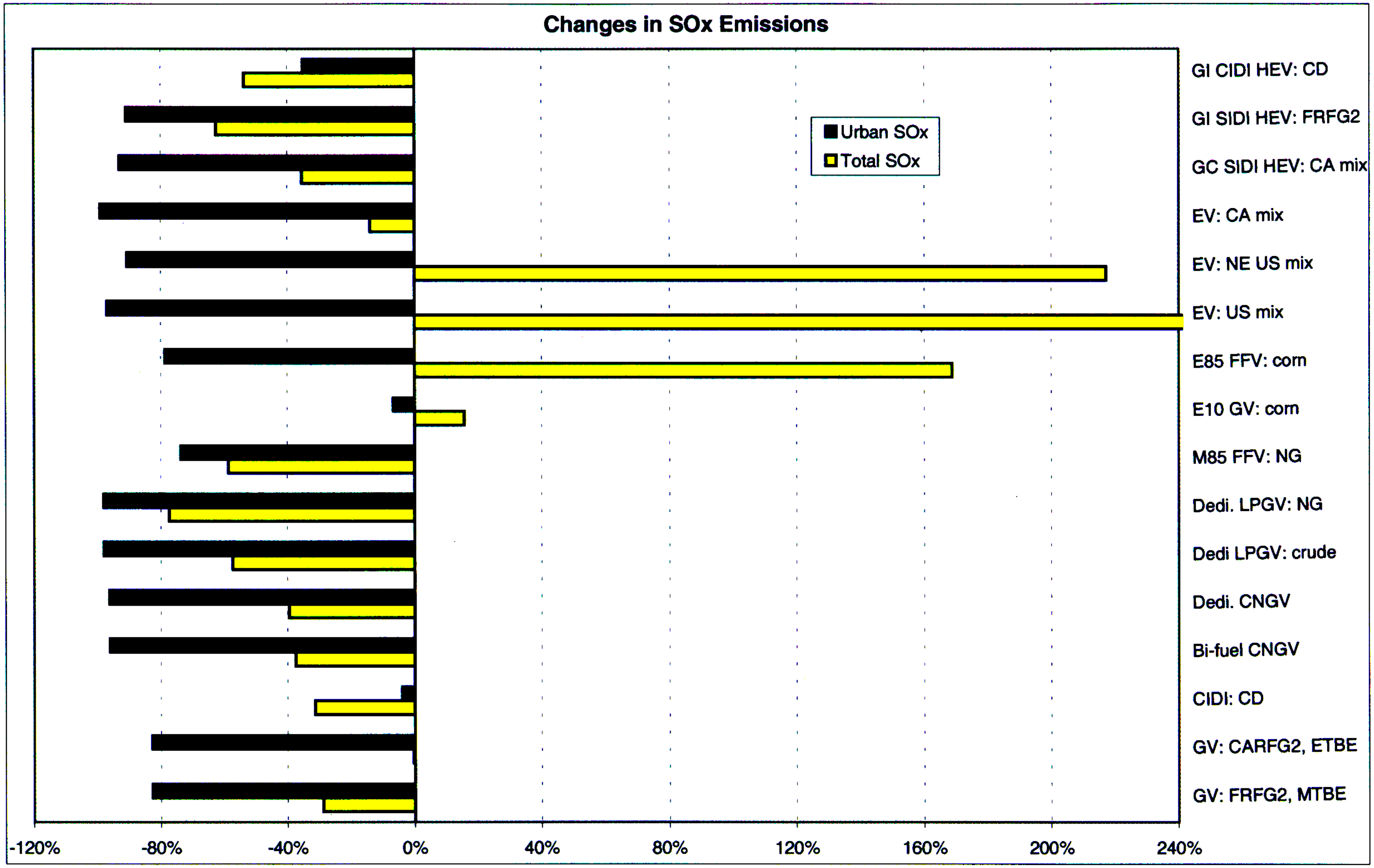

Figure 6.30 Changes in Fuel-Cycle SO_x Emissions Relative to GVs Fueled with CG: Near-Term Technologies

for each of the four groups and for each energy or pollutant to show fuel-cycle energy and emission effects.

Figures 6.31 through 6.34 show changes in fuel-cycle total energy use. Figure 6.31 shows total energy changes for SI and SIDI vehicles. Use of methanol from commercial natural gas or flared gas or ethanol from corn, woody biomass, or herbaceous biomass results in increased total energy use (note that total energy use includes the energy contained in corn and biomass that eventually comes from solar energy through the photosynthesis process). These increases are caused by the large amount of energy consumed during methanol or ethanol production. Use of LPGVs and SIDI vehicles fueled with RFG and methanol from landfill gases results in 15–20% reductions in total energy. The reduction by LPGVs is primarily because only a small amount of energy is consumed during LPG fractionating in petroleum refineries or in NG processing plants. The reductions by SIDI vehicles in general are attributable to their increased fuel economy.

Figure 6.32 shows reductions in total energy use by SI and SIDI HEVs. Technology options here include GI and GC HEVs. Conventional SI engines rather than SIDI engines were assumed for LPG, CNG, and LNG, because no significant fuel economy benefits are offered by replacing SI engines with SIDI engines for these fuels. On the other hand, SIDI engines were assumed for RFG, methanol, and ethanol. Large reductions (35–45%) are achieved for these vehicle types except for HEVs fueled with ethanol produced from woody and herbaceous biomass, for which reductions are 10–20%. The lower reductions for these options are caused by the large amount of energy consumed in cellulosic ethanol plants.

Figure 6.33 shows reductions in total energy use by CIDI standalone vehicles and CIDI HEVs. The former achieves 10–30% reductions, and the latter achieves over 40% reductions. Use of DME and FT50 results in lower reductions than use of other CI engine fuels because production of DME and FTD consumes a significant amount of energy.

Figure 6.34 presents reductions in total energy use by EVs and FCVs. Except for FCVs fueled with cellulosic ethanol (reductions of 10–20%), all the vehicles reduce total energy use by 40–60%. The smaller reductions by cellulosic ethanol are caused (again) by the large amount of energy consumed in cellulosic ethanol plants.

The four figures together show that SIDI HEVs, CIDI HEVs, and FCVs achieve large reductions in total energy use because of their significant improvements in vehicle fuel economy relative to gasoline SI engine technology.

Figures 6.35 through 6.38 present changes in fuel-cycle fossil energy use for the four technology groups. Figure 6.35 shows that, among the SI and SIDI vehicles, use of methanol produced from NG results in about a 10% increase in fossil energy use because of the large amount of NG consumed in methanol plants. On the other hand, use of flared gas- or landfill gas-based methanol results in 50–70% reductions in fossil energy because the energy contained in landfill gas or flared gas is otherwise wasted, and therefore it is not accounted for in GREET’s fossil energy calculations. Use of CNG, LNG, and LPG achieves less than 20% reductions in fossil energy use. Use of ethanol reduces fossil energy use by 50% to over 80%

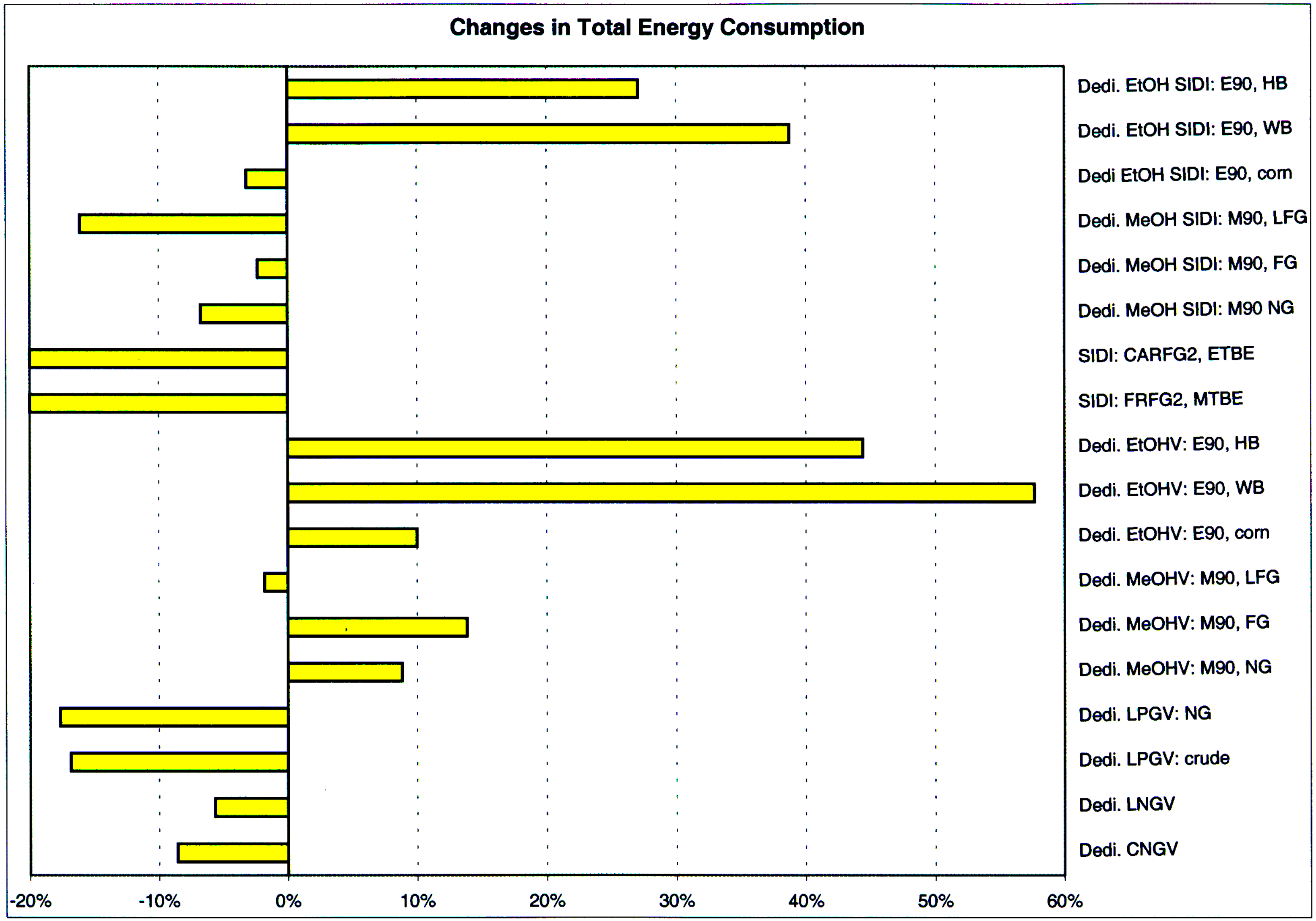

Figure 6.31 Changes in Fuel-Cycle Total Energy Use Relative to GVs Fueled with RFG: Long-Term SI and SIDI Vehicles

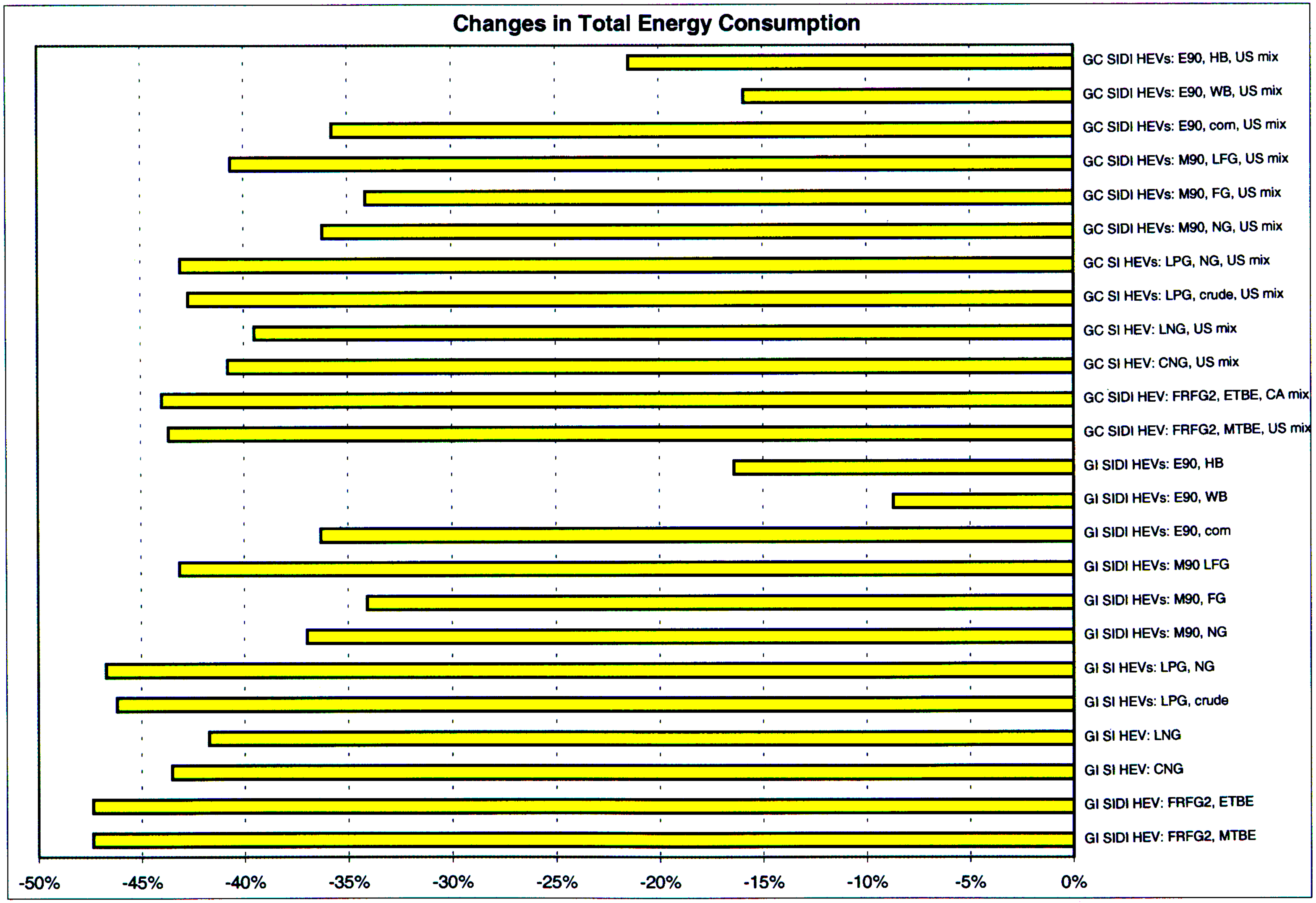

Figure 6.32 Changes in Fuel-Cycle Total Energy Use Relative to GVs Fueled with RFG: Long-Term SI and SIDI HEVs

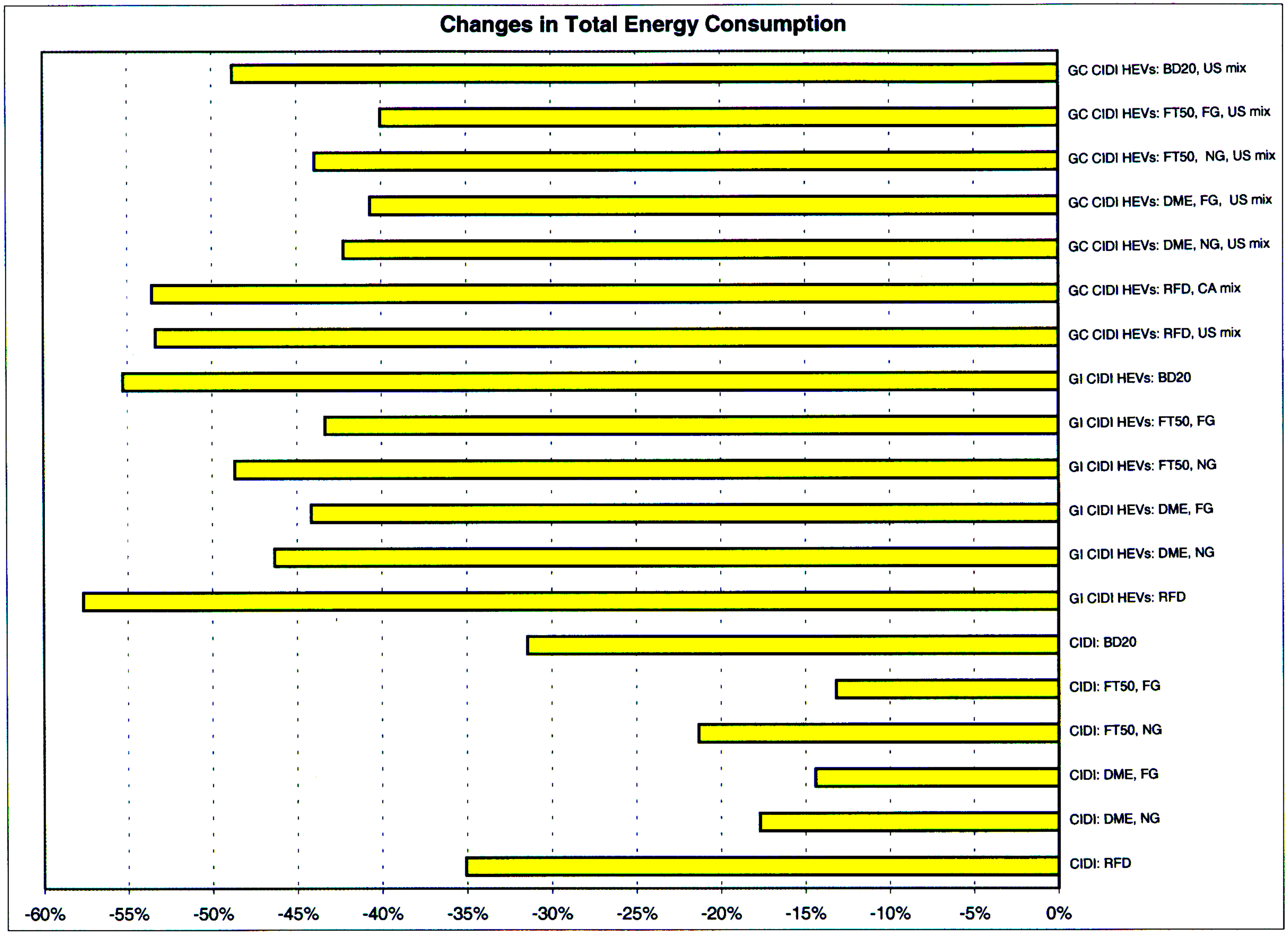

Figure 6.33 Changes in Fuel-Cycle Total Energy Use Relative to GVs Fueled with RFG: Long-Term CIDI Vehicles and CIDI HEVs

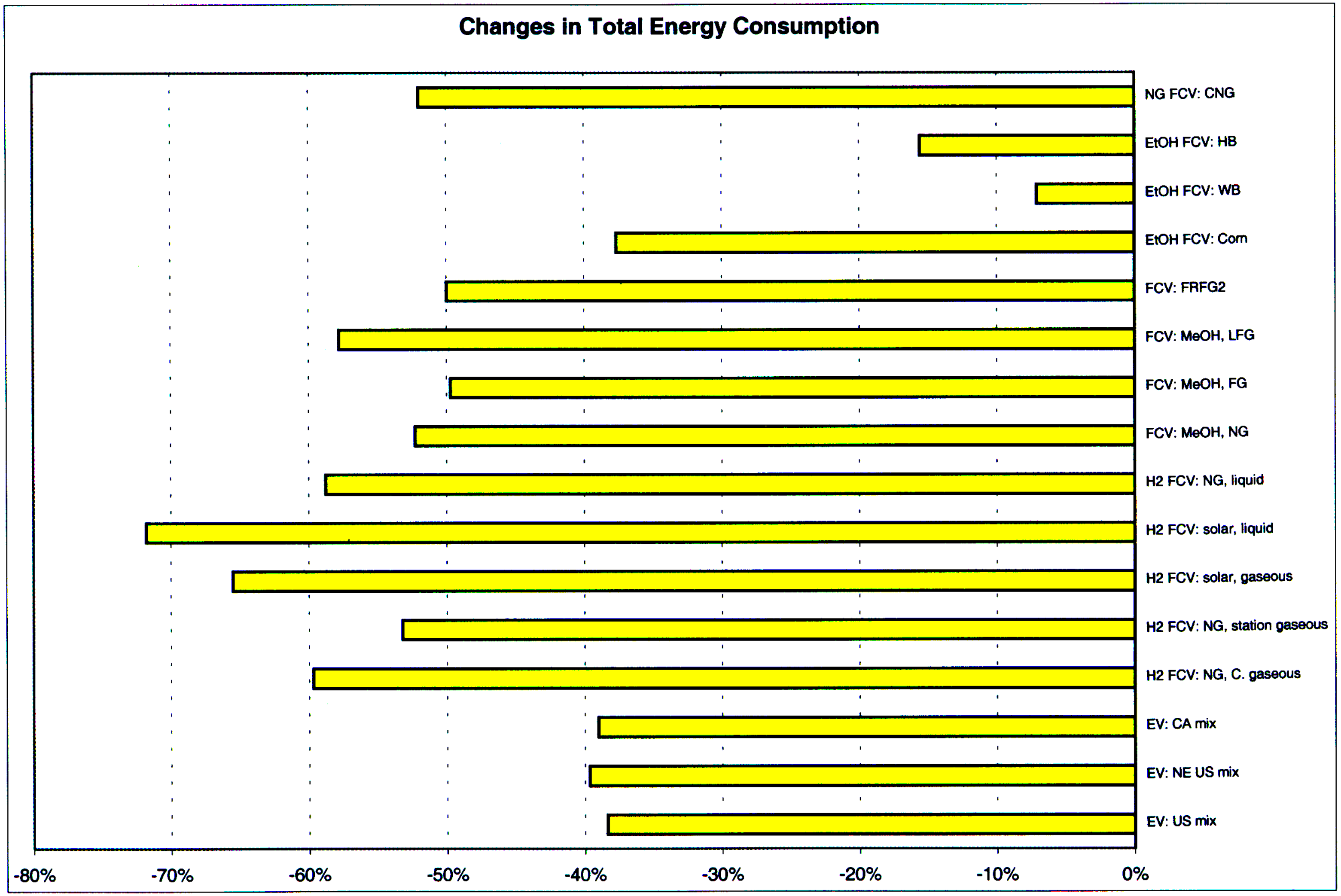

Figure 6.34 Changes in Fuel-Cycle Total Energy Use Relative to GVs Fueled with RFG: Long-Term EVs and FCVs

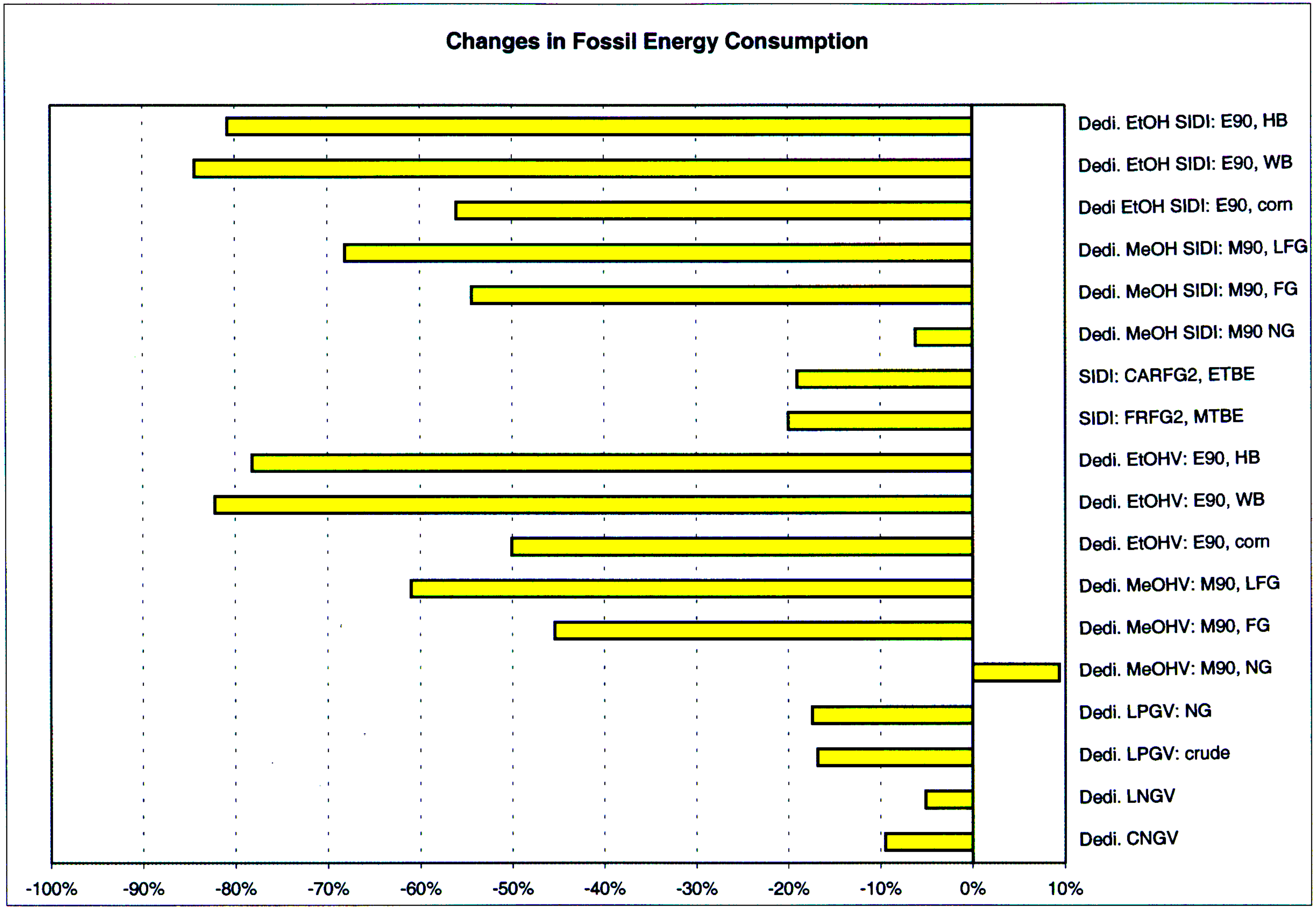

Figure 6.35 Changes in Fuel-Cycle Fossil Energy Use Relative to GVs Fueled with RFG: Long-Term SI and SIDI Vehicles

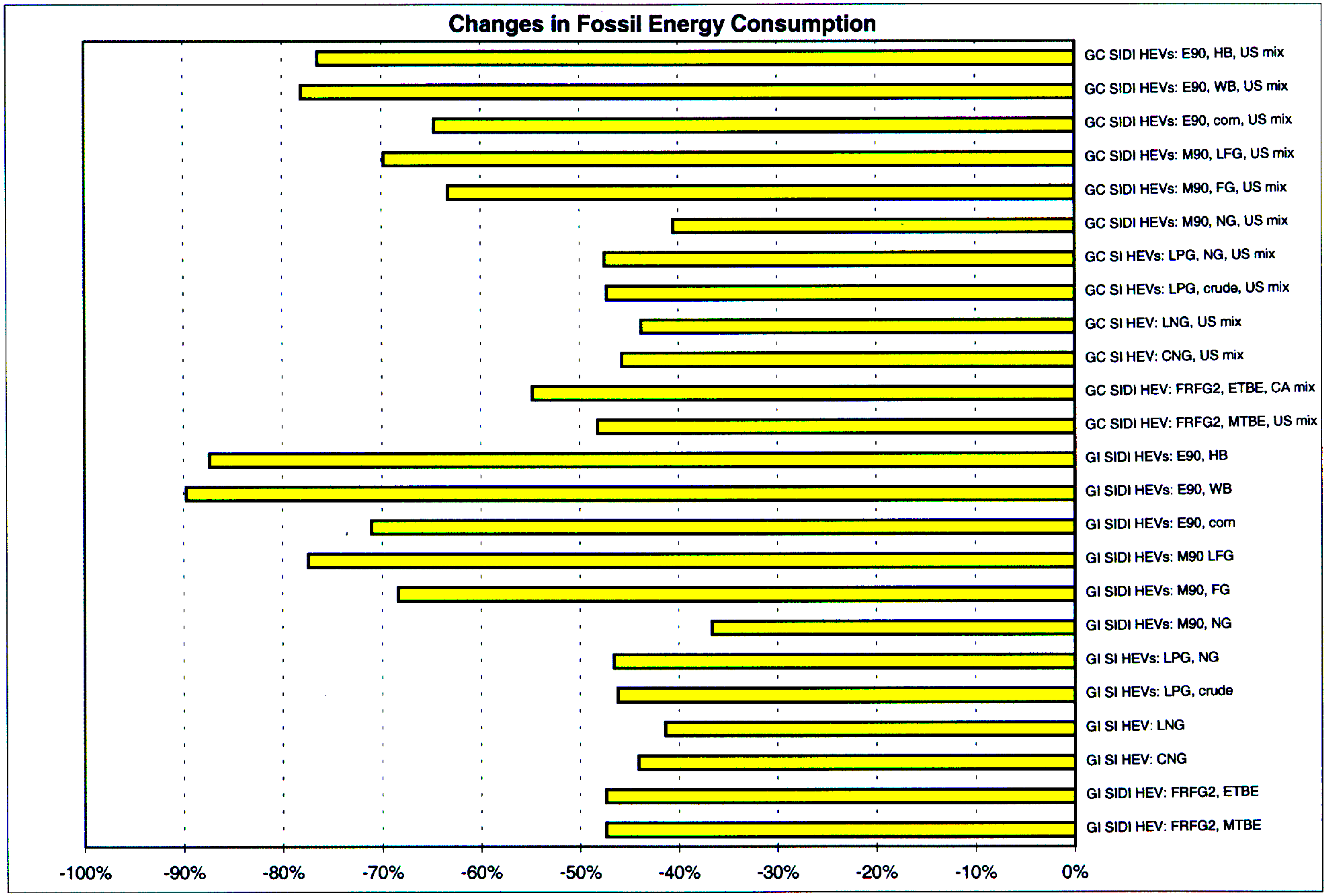

Figure 6.36 Changes in Fuel-Cycle Fossil Energy Use Relative to GVs Fueled with RFG: Long-Term SI and SIDI HEVs

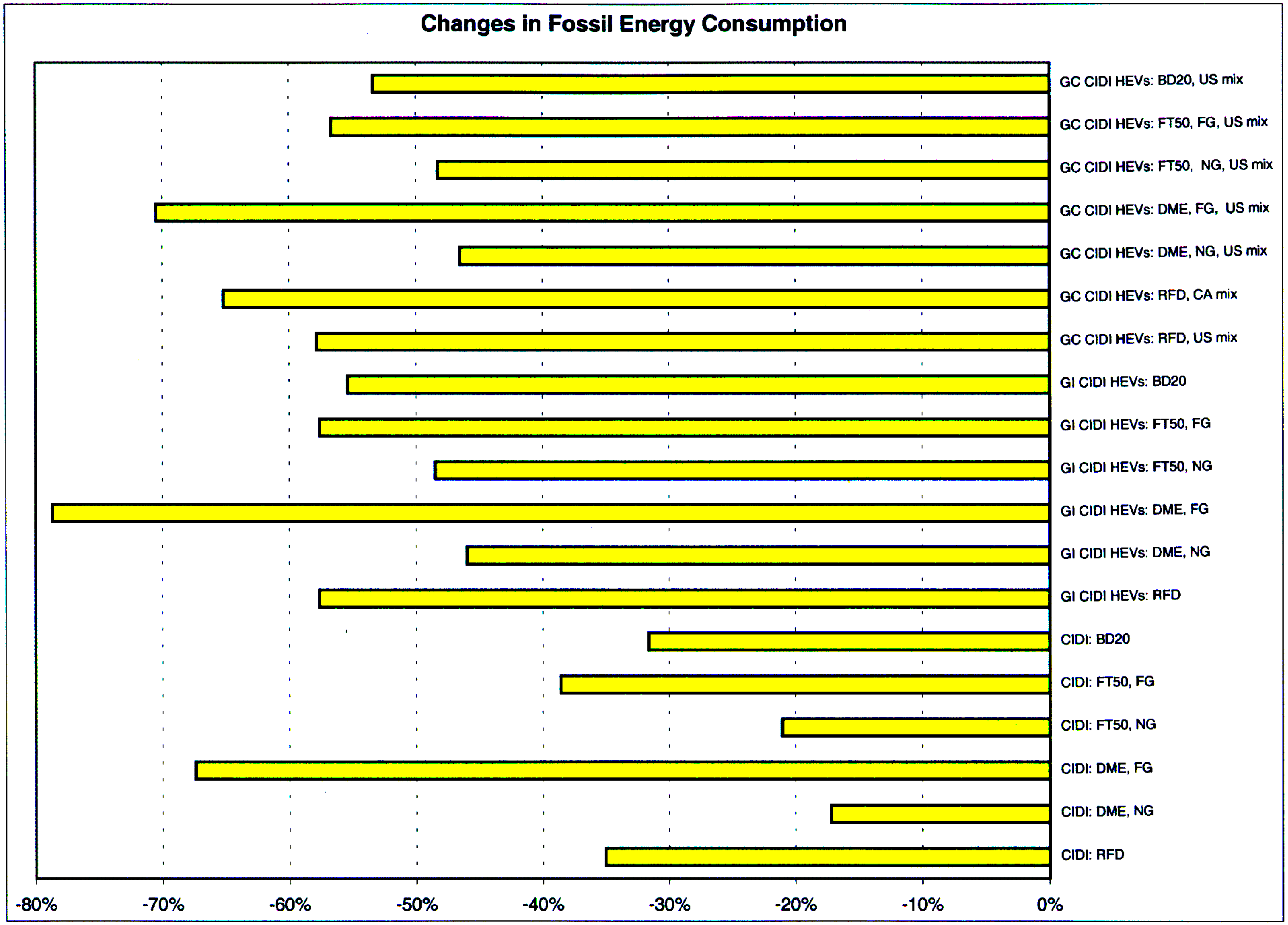

Figure 6.37 Changes in Fuel-Cycle Fossil Energy Use Relative to GVs Fueled with RFG: Long-Term CIDI Vehicles and CIDI HEVs

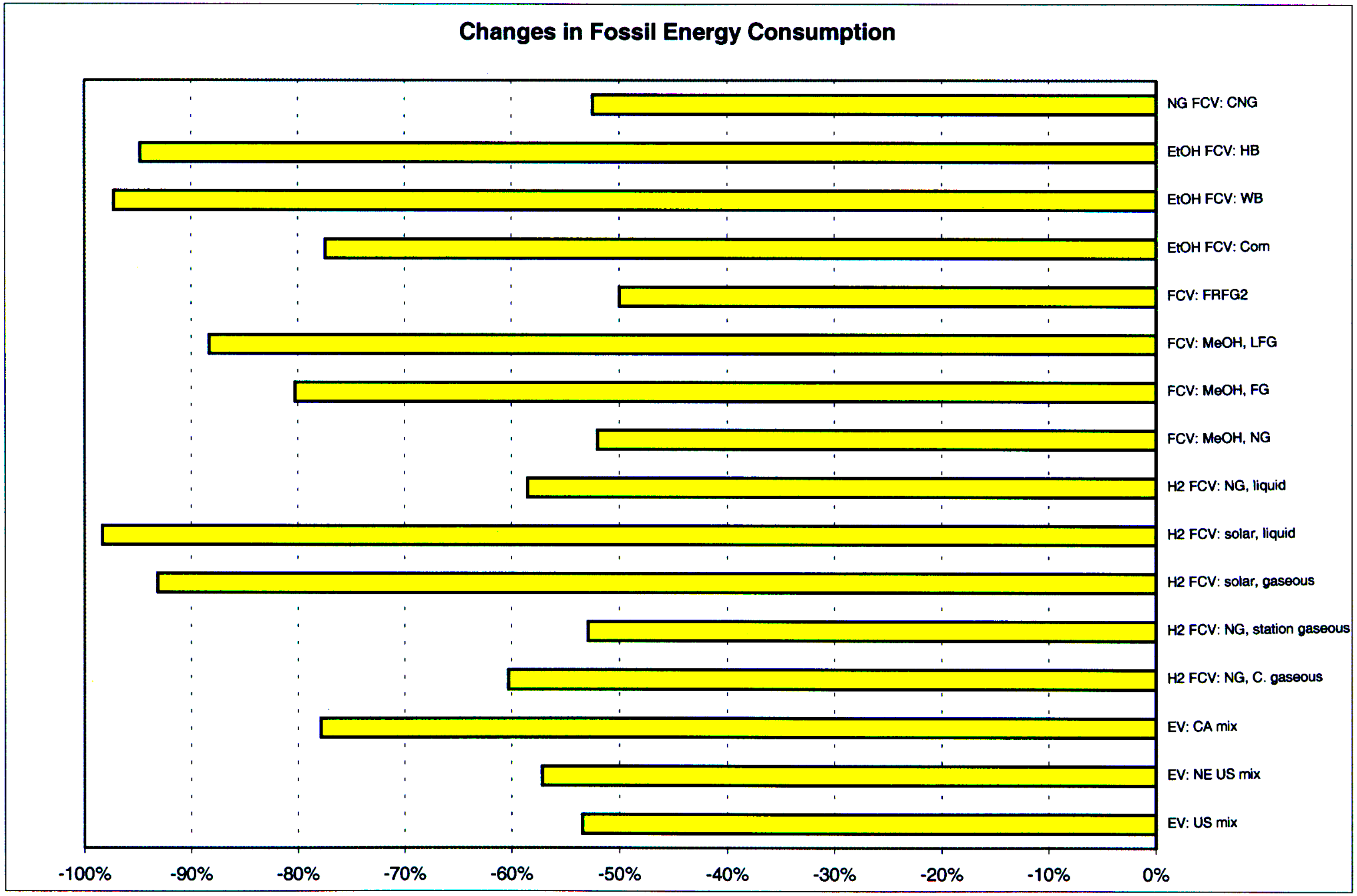

Figure 6.38 Changes in Fuel-Cycle Fossil Energy Use Relative to GVs Fueled with RFG: Long-Term EVs and FCVs

because the energy in ethanol eventually comes from solar energy during the photosynthesis process. Overall, advanced SIDI engines achieve greater fossil energy reductions than conventional SI engines.

Figure 6.36 shows reductions in fossil energy use by SI and SIDI HEVs. The magnitude of reductions can be separated into two distinct levels. At the first level, reductions range from 35% to 50%. Fuels include those produced from fossil energy sources (i.e., petroleum and natural gas). The reductions here are attributable to fuel economy improvements of the vehicle technologies. At the second level, reductions in fossil energy use reach 70–90%. Fuels include those produced from renewable sources (corn and biomass for ethanol) and waste energy sources (landfill gas and flared gas for methanol). The reductions here are attributable to vehicle fuel economy improvements and use of non-fossil energy sources.

Figure 6.37 presents fossil energy reductions by CIDI vehicles and CIDI HEVs. Use of DME and FT50 in CIDI vehicles achieves about 20% reductions. The small reductions are caused by inefficiencies in DME and FTD production. Use of all the CI engine fuels in HEVs achieves greater-than-50% reductions in fossil energy use because of the significant increases in fuel economy by these vehicles.

Figure 6.38 shows reductions in fossil energy use by EVs and FCVs. Again, the reductions are at two distinct levels. At the first level, reductions between 50–60% are achieved. Vehicles at this level include EVs with the U.S. and Northeast U.S. electric generation mix and FCVs fueled with NG-based H_2, NG-based methanol, RFG, and CNG. Reductions by these vehicles are caused by improved vehicle fuel economy. The second level shows fossil energy reductions of 80–95%. Vehicles at this level include EVs with the California electric generation mix and FCVs fueled with H_2 from solar energy, landfill gas- and flared gas-based methanol, and ethanol. The additional reductions by these vehicles are attributable to use of renewable energy sources or waste energy sources.

Overall, the four figures show increased fossil energy reductions in the following order: SI, SIDI, CIDI, HEVs, EVs, and FCVs. Reductions are from two sources: improved vehicle fuel economy and substitution of fossil fuels (petroleum and natural gas) with non-fossil fuels (renewable and waste energy sources).

Figures 6.39 through 6.42 present petroleum use reductions by the long-term technology options. Figure 6.39 shows reductions by SI and SIDI vehicles. Use of petroleum-based LPG in SI vehicles has little effect on petroleum use. Use of RFG in SIDI vehicles achieves about a 20% reduction because of SIDI efficiency gains. Use of non-petroleum fuels achieves 80% to almost 100% reductions. The reductions of around 80% by M90 and E90 are attributable to the fact that 10% gasoline is used in these fuel blends. Figure 6.40 indicates petroleum use reductions by SI and SIDI HEVs. Introduction of HEVs helps increase petroleum reductions (compare with Figure 6.39). For example, use of M90 and E90 in HEVs can now achieve over 90% reductions. Figure 6.41 shows reductions by CIDI engines in standalone and hybrid applications. While improved fuel economy helps reduce petroleum use for all of the cases, use of non-petroleum fuels achieves further reductions. Note that the reductions with FT50 and BD20 are smaller because petroleum-based diesel is used in both blends. Figure 6.42 presents

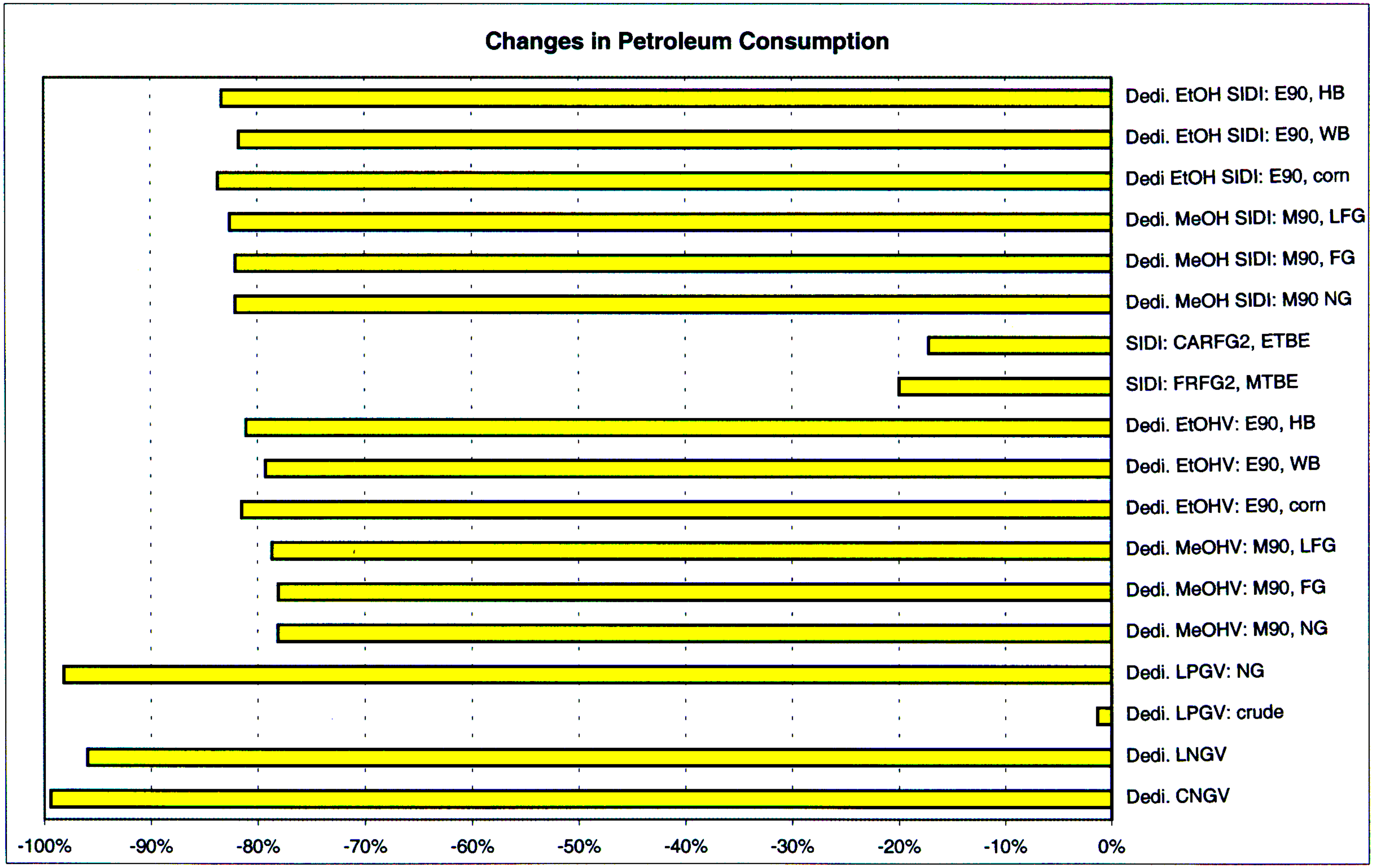

Figure 6.39 Changes in Fuel-Cycle Petroleum Use Relative to GVs Fueled with RFG: Long-Term SI and SIDI Vehicles

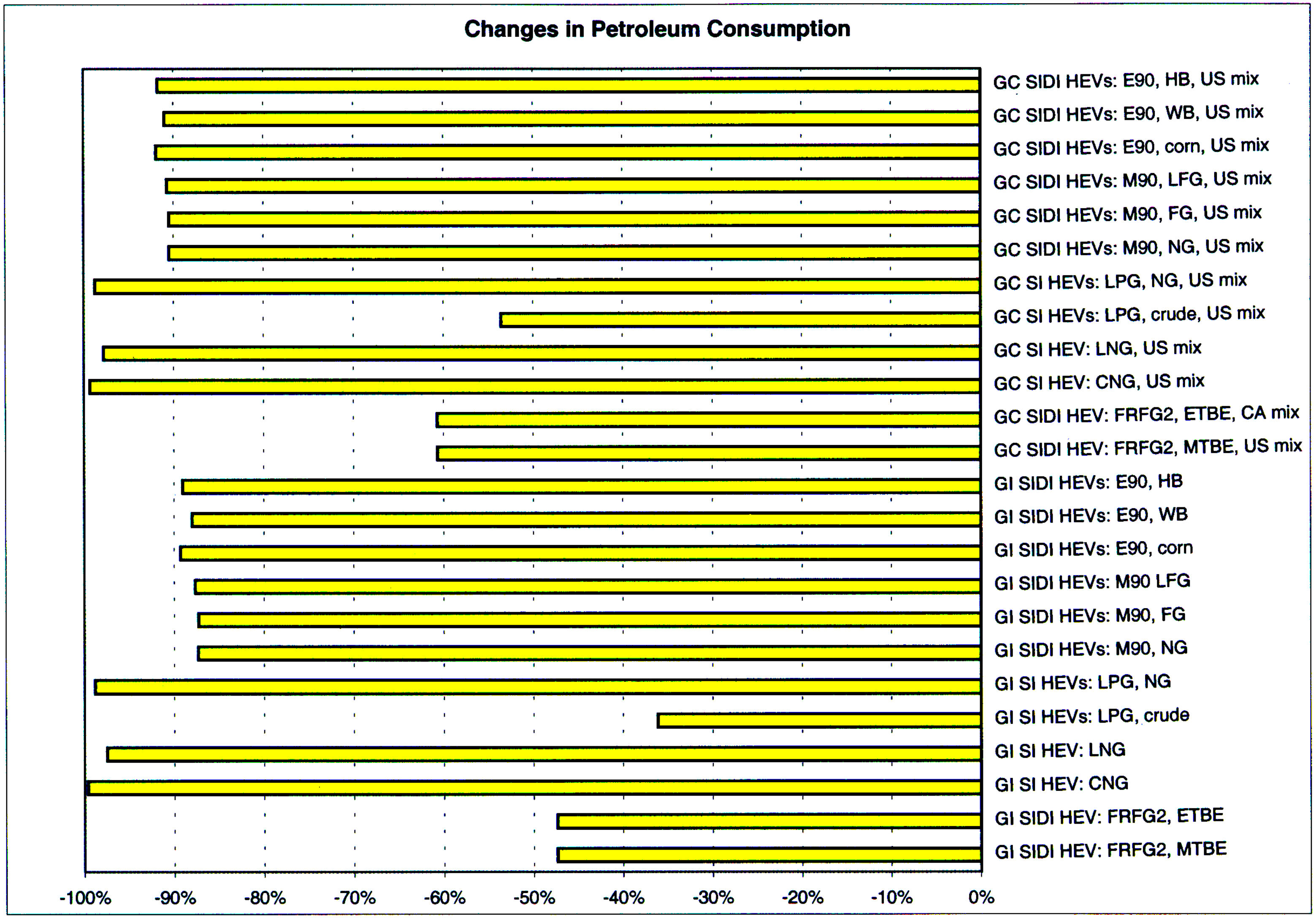

Figure 6.40 Changes in Fuel-Cycle Petroleum Use Relative to GVs Fueled with RFG: Long-Term SI and SIDI HEVs

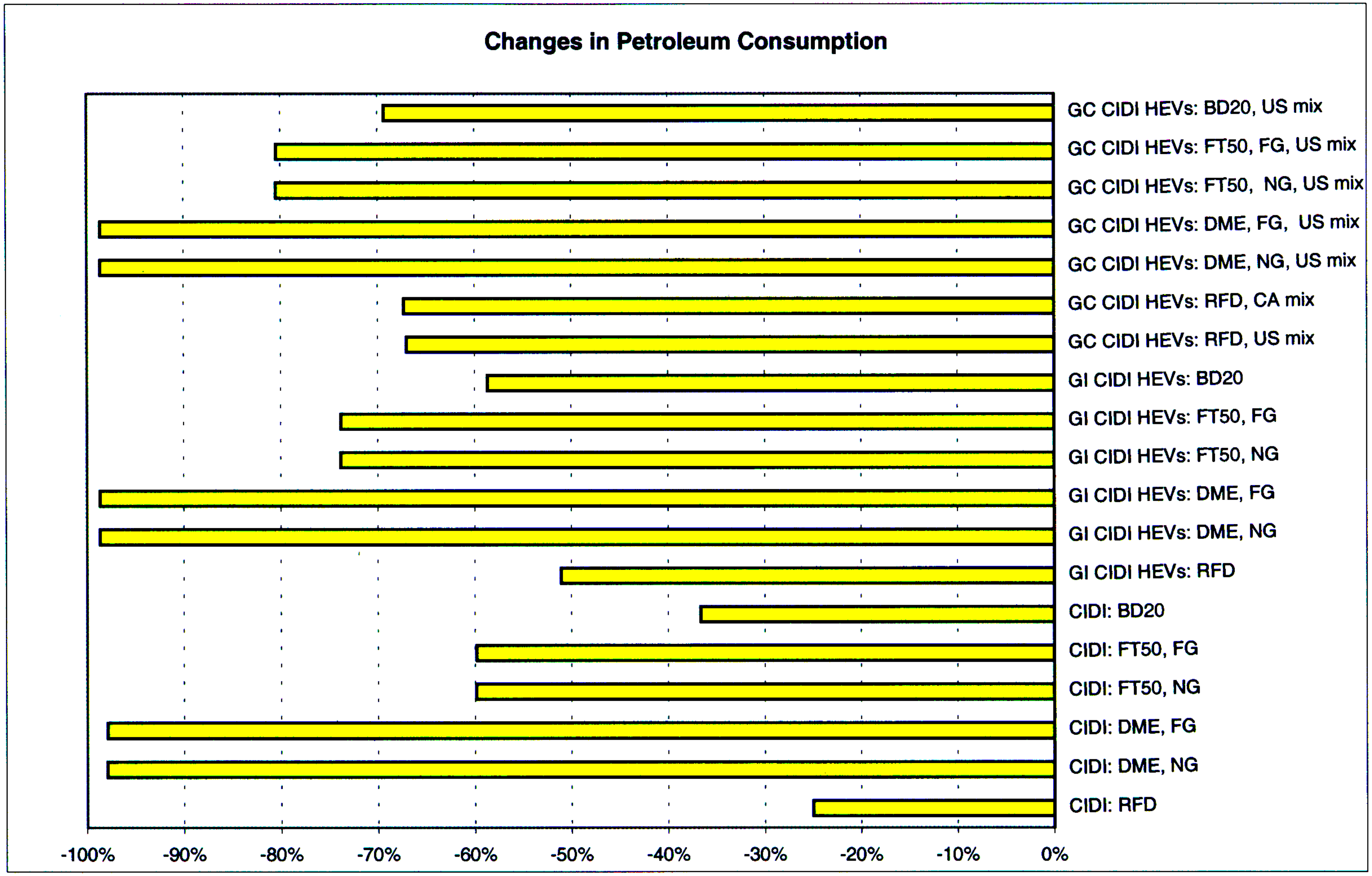

Figure 6.41 Changes in Fuel-Cycle Petroleum Use Relative to GVs Fueled with RFG: Long-Term CIDI Vehicles and CIDI HEVs

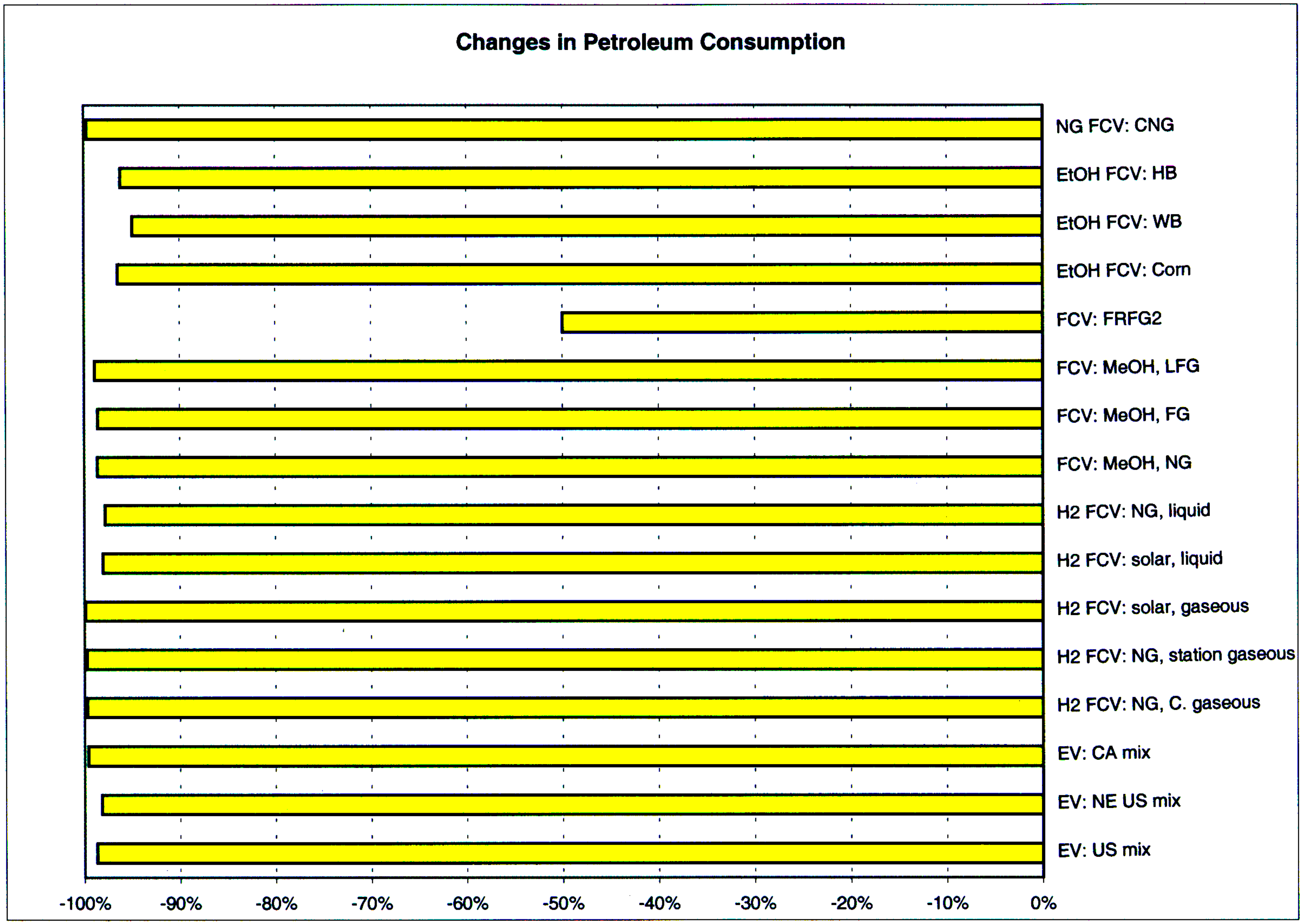

Figure 6.42 Changes in Fuel-Cycle Petroleum Use Relative to GVs Fueled with RFG: Long-Term EVs and FCVs

results for EVs and FCVs. Except for FCVs fueled with RFG, all of these cases nearly eliminate petroleum use.

Again, the four figures show the increased benefits in petroleum reductions from SI engines to SIDI engines, to CIDI engines, to HEVs, to EVs, and to FCVs and the benefits of switching from petroleum-based to non-petroleum-based fuels.

Figures 6.43 through 6.46 present reductions in CO_2-equivalent GHG emissions by the long-term technologies. GHG emissions here include emissions of CO_2, CH_4, and N_2O. These emissions were converted into CO_2-equivalent emissions by using IPCC-adopted GWPs (1 for CO_2, 21 for CH_4, and 310 for N_2O). Figure 6.43 shows GHG emission reductions by SI and SIDI vehicles. Use of CNG, LNG and LPG in SI engines and RFG and M90 in SIDI engines achieves 20–25% reductions. Use of M90 in SI engines achieves about a 10% reduction. Use of ethanol made from corn reduces GHG emissions by 40–45%. Use of cellulosic ethanol and flared gas-based methanol results in 80–100% reductions. Use of landfill gas-based methanol reduces GHG emissions by over 140%. The large reductions by cellulosic ethanol are attributable to CO_2 sequestration during the photosynthesis process and to the GHG emission credits for the extra electricity generated in cellulosic ethanol plants. The large reductions by flared gas- and landfill gas-based methanol are attributable to elimination of CH_4 venting and CO_2 combustion emissions associated with gas flaring.

Figure 4.44 shows GHG emission reductions by SI and SIDI HEVs. Use of fossil energy-based fuels (RFG, CNG, LNG, LPG, and NG-based methanol) achieves around 50% reductions, mainly because of improved vehicle fuel economy. Use of fuels produced from renewable or waste energy sources results in much higher reductions. GC HEVs with the California electric generation mix achieve greater reductions than GI HEVs.

Figure 4.45 presents GHG emission reductions by CIDI vehicles and CIDI HEVs. Use of RFD, FT50, and BD20 in CIDI standalone vehicles reduces GHG emissions by 30–40%. Hybridization of CIDI engines helps increase GHG emission reductions to above 50%. Use of DME and FTD produced from flared gas reduces GHG emissions even further.

Figure 4.46 shows GHG emission reductions by EVs and FCVs. EVs with the U.S. electric generation mix and FCVs powered by RFG achieve about 50% reductions. EVs with the Northeast U.S. and California generation mixes achieve additional reductions. FCVs fueled with NG-based H_2, NG-based methanol, corn-based ethanol, and CNG achieve 60–70% reductions. Use of solar H_2, flare gas- and landfill gas-based methanol, and cellulosic ethanol in FCVs results in over-90% reductions.

Overall, large GHG emission reductions are achieved by using advanced engine and vehicle technologies that have much higher fuel economy than baseline GVs and by switching from fossil energy-based fuels to renewable fuels. The results here quantitatively show the effects of fuel economy improvements and alternative fuels on motor vehicle GHG emissions. The four figures also show the differences in CO_2 and GHG emission reductions. If CH_4 and N_2O emissions are not included (as for CO_2 emission changes only), GHG emission reductions by NG-based fuels and ethanol would be overestimated. This is because a significant amount of

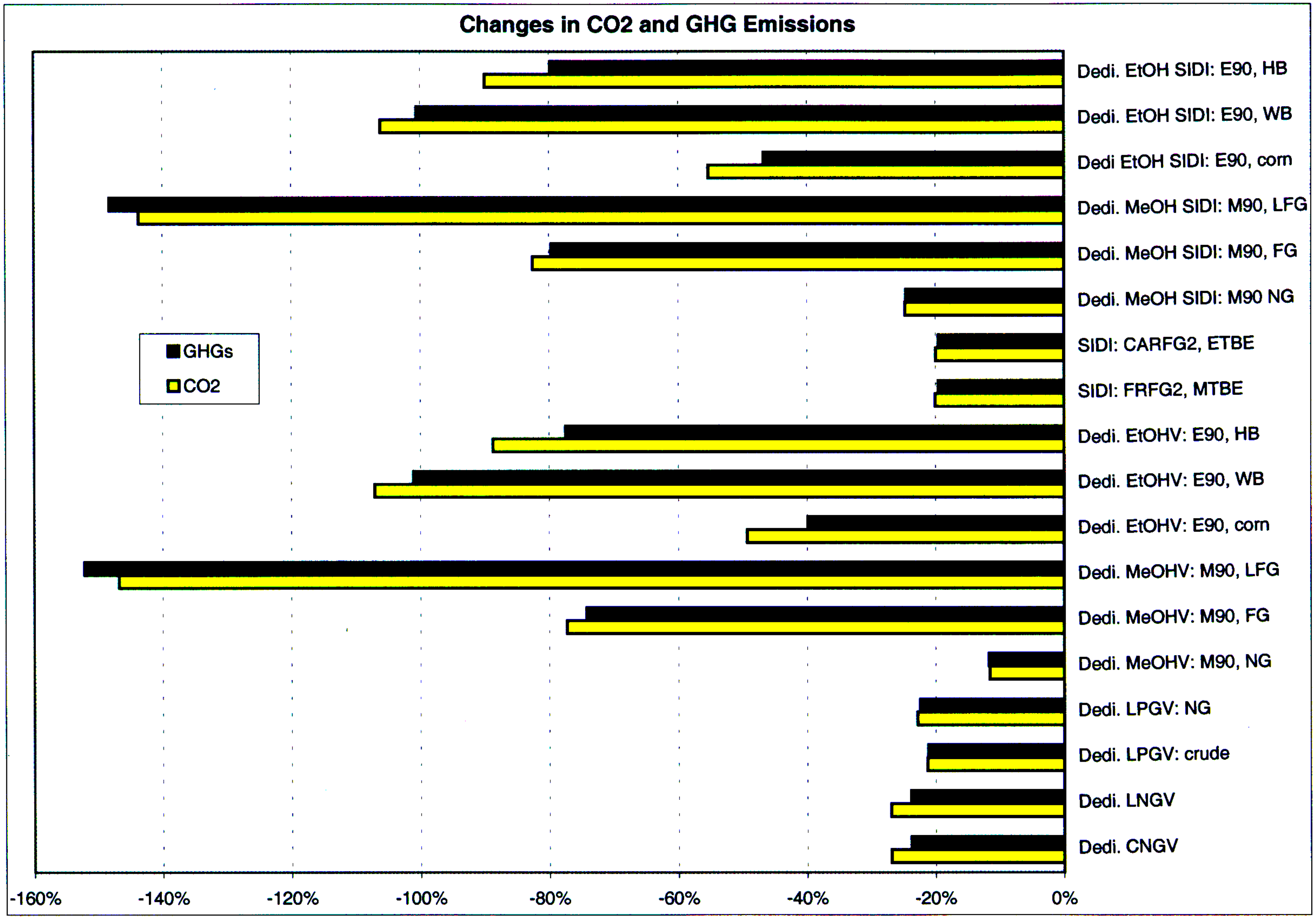

Figure 6.43 Changes in Fuel-Cycle CO_2-Equivalent GHG Emissions Relative to GVs Fueled with RFG: Long-Term SI and SIDI Vehicles

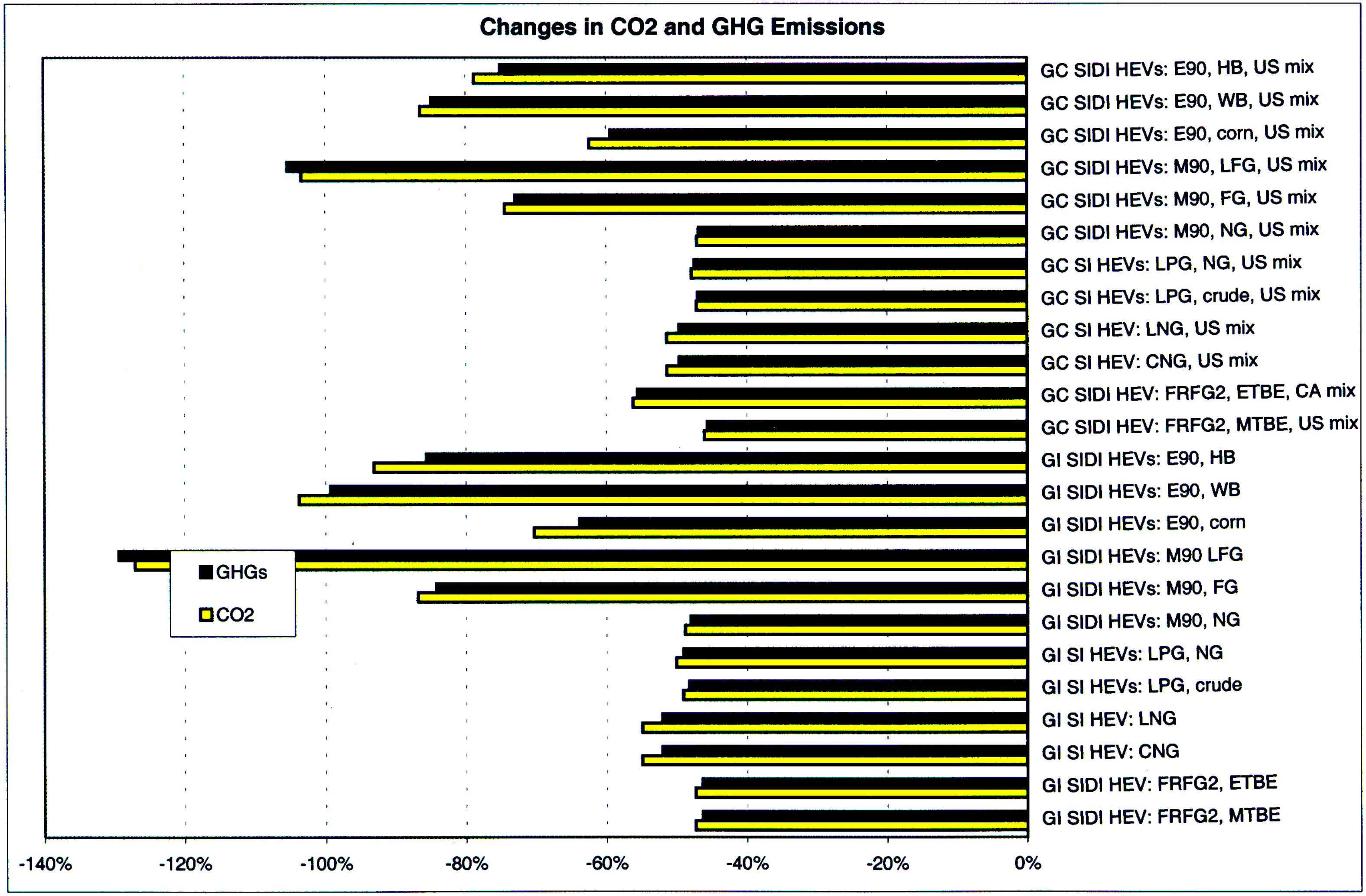

Figure 6.44 Changes in Fuel-Cycle CO_2-Equivalent GHG Emissions Relative to GVs Fueled with RFG: Long-Term SI and SIDI HEVs

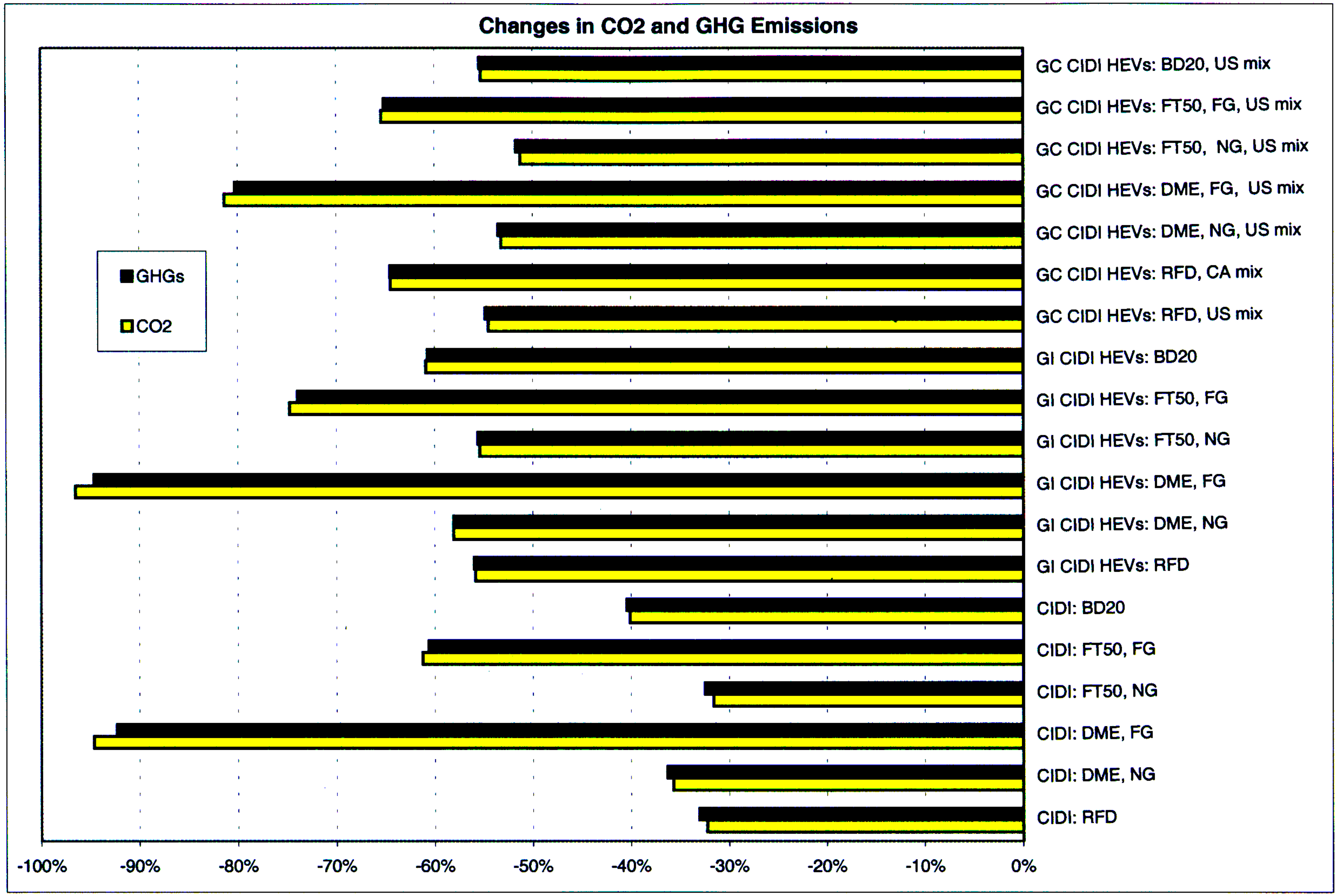

Figure 6.45 Changes in Fuel-Cycle CO_2-Equivalent GHG Emissions Relative to GVs Fueled with RFG: Long-Term CIDI Vehicles and CIDI HEVs

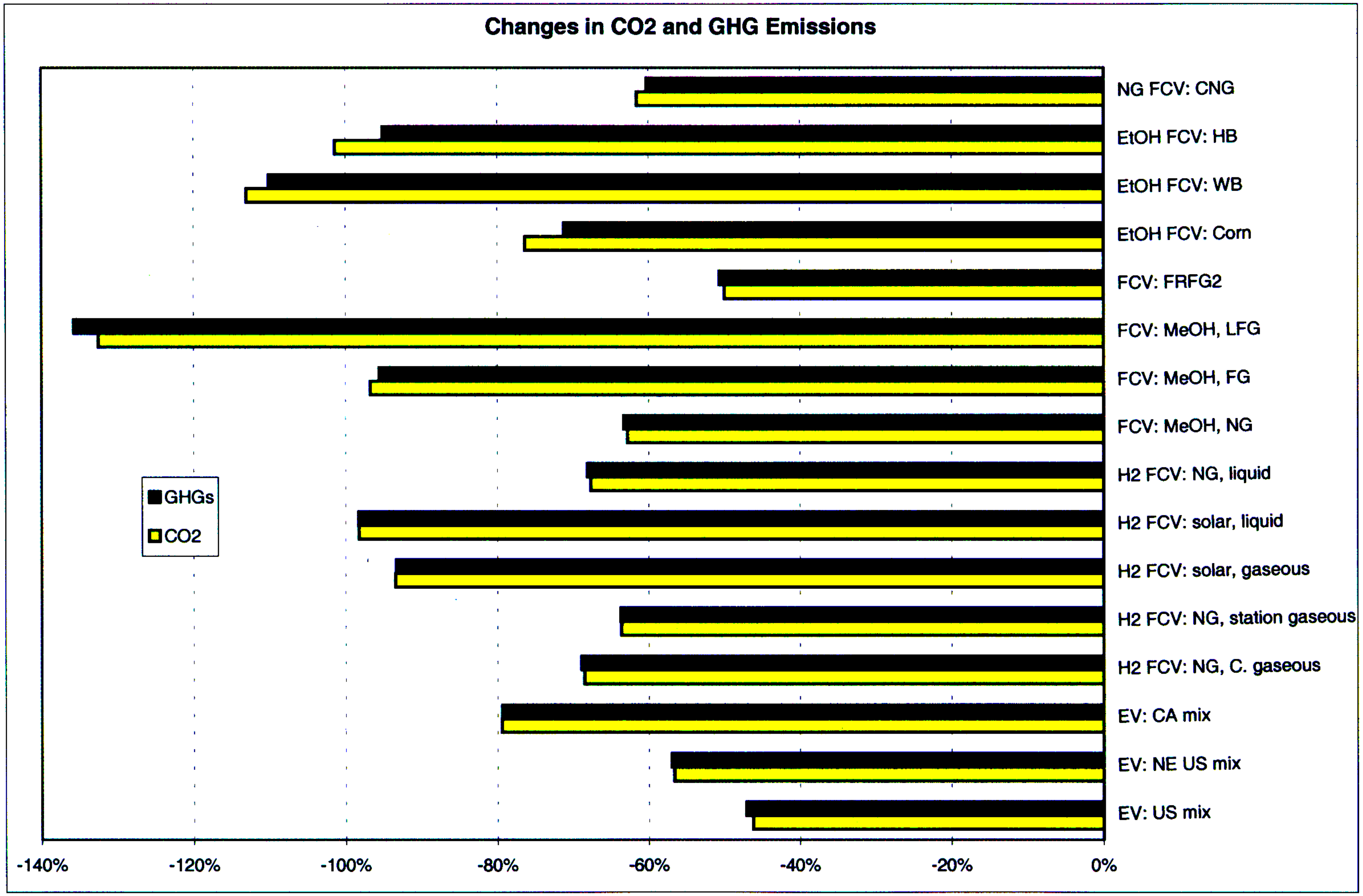

Figure 6.46 Changes in Fuel-Cycle CO_2-Equivalent GHG Emissions Relative to GVs Fueled with RFG: Long-Term EVs and HEVs

CH_4 emissions are associated with NG-based fuel pathways, and a significant amount of N_2O emissions results from nitrification and denitrification of nitrogen fertilizers in cornfields and biomass farms.

Figures 6.47 through 6.50 present changes in total and urban VOC emissions by the long-term technologies. For the five criteria pollutants, total emissions include emissions from fuel-cycle activities occurring everywhere, while urban emissions include emissions that occur only within urban areas; upstream emissions occurring outside of urban areas are excluded. Figure 6.47 shows VOC emission changes by SI and SIDI vehicles. Total VOC emissions are increased substantially by corn-based ethanol because of the VOC emissions from tractors used for corn farming and from ethanol production in ethanol plants. On the other hand, total VOC emissions are reduced by nearly 150% for flared gas-based methanol, which eliminates the VOC emissions associated with gas flaring during methanol production. Use of CNG, LNG, and LPG achieves 40–60% reductions in VOC emissions, primarily because VOC evaporative emissions from baseline gasoline vehicles are eliminated. VOC emission reductions by M90 and E90 vehicles are limited because these fuels still produce evaporative emissions.

Figure 6.48 presents VOC emission changes for SI and SIDI HEVs. Again, total VOC emissions are increased for corn-based ethanol, although the increase is much smaller. Total VOC emissions are significantly reduced by using flared gas-based methanol, which eliminates VOC emissions from gas flaring. Use of CNG, LNG, and LPG achieves about 50% reductions for GI HEVs and about 70% reductions for GC HEVs. In general, use of HEVs reduces both total and urban VOC emissions because of the vehicles' improved fuel economy, which helps reduce both upstream and vehicle evaporative emissions.

Figure 6.49 shows that use of CIDI standalone vehicles and CIDI HEVs achieves VOC emission reductions ranging from 40% to 80%, relative to use of GVs. The reductions result from elimination of GV evaporative emissions by CI fuels. Note that use of flared gas-based DME and FTD achieves huge reductions in total VOC emissions.

As Figure 6.50 shows, EVs and FCVs achieve uniform VOC emission reductions. Reductions by EVs and H_2- and CNG-fueled FCVs are almost 100% because these vehicles generate no tailpipe or evaporative VOC emissions. Reductions by FCVs fueled with methanol, ethanol, and gasoline are smaller because these fuels produce evaporative emissions, despite zero exhaust emissions.

Overall, the magnitude of VOC emission reductions is in the following order (from small to large): SI and SIDI standalone vehicles, SI and SIDI HEVs, CIDI vehicles and CIDI HEVs, and FCVs.

Figures 6.51 through 6.54 show changes in total and urban CO emissions by the long-term technology options. In Figure 6.51, use of CNG, LNG, and LPG reduces CO emissions by about 20%. Use of ethanol results in increased total CO emissions because of the high CO emissions associated with tractors used during farming and with ethanol production. Use of landfill gas-based methanol helps reduce both total and urban CO emissions by eliminating CO emissions from landfill gas burning. Other fuel options have little effect on CO emissions.

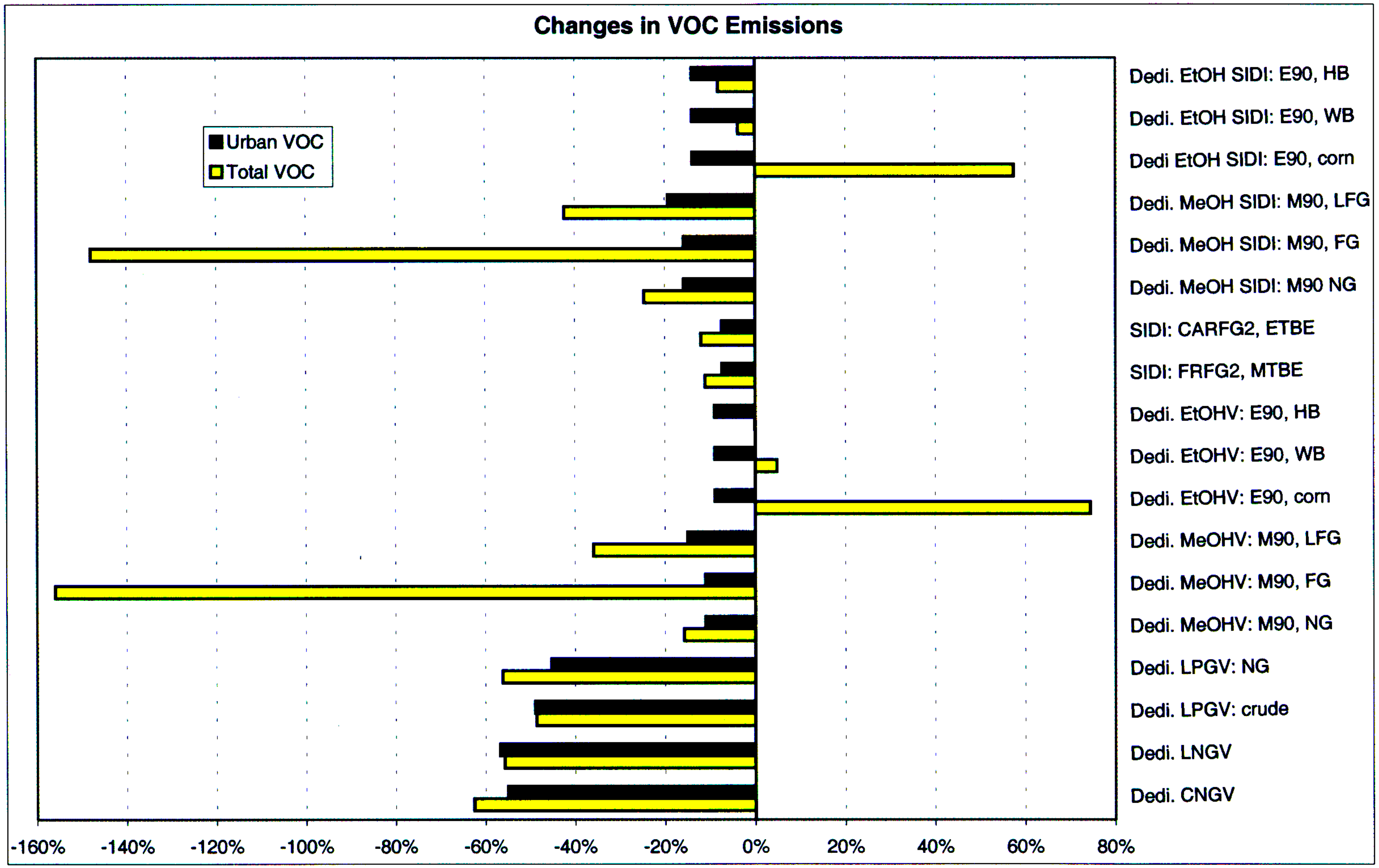

Figure 6.47 Changes in Fuel-Cycle Total and Urban VOC Emissions Relative to GVs Fueled with RFG: Long-Term SI and SIDI Vehicles

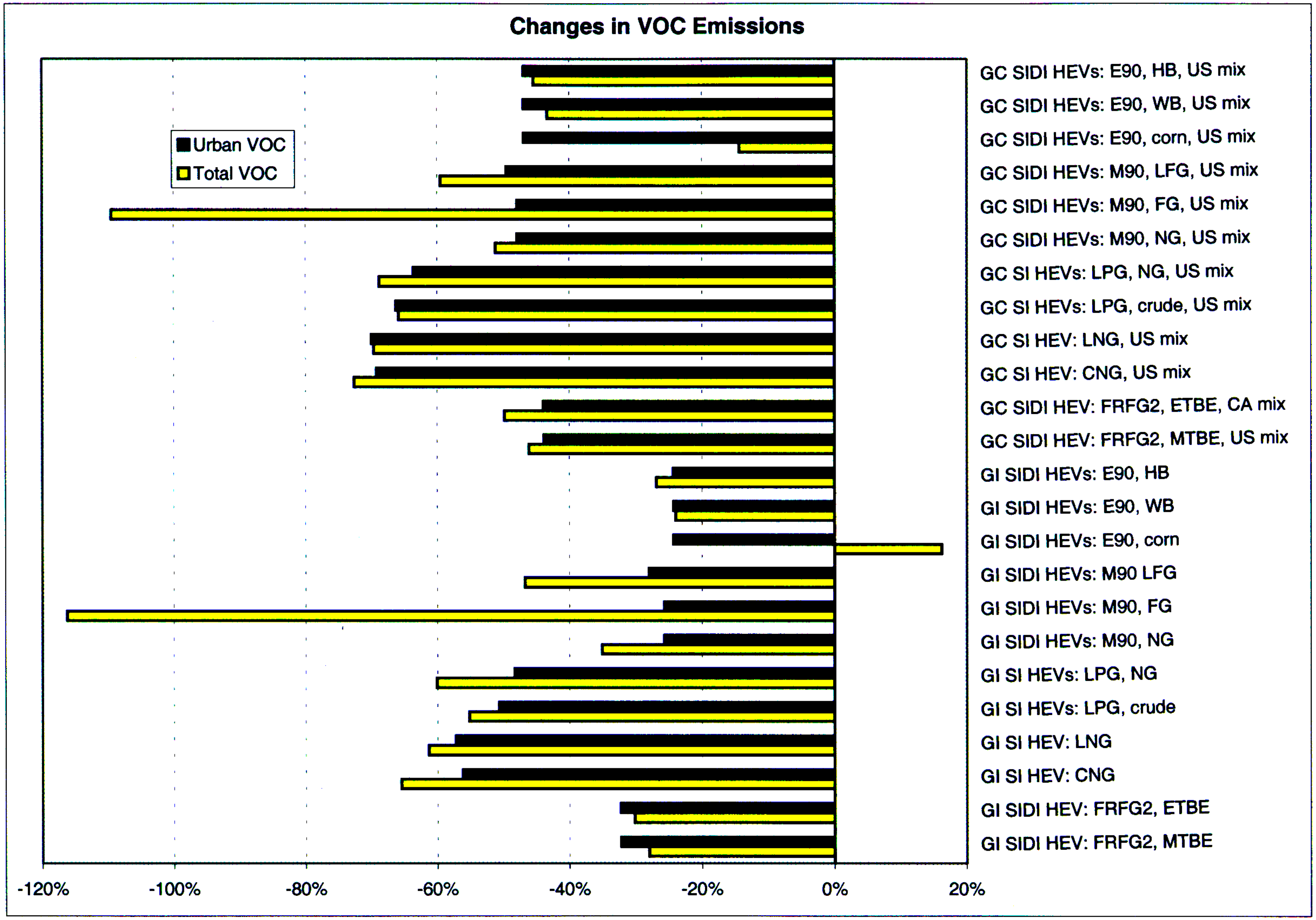

Figure 6.48 Changes in Fuel-Cycle Total and Urban VOC Emissions Relative to GVs Fueled with RFG: Long-Term SI and SIDI HEVs

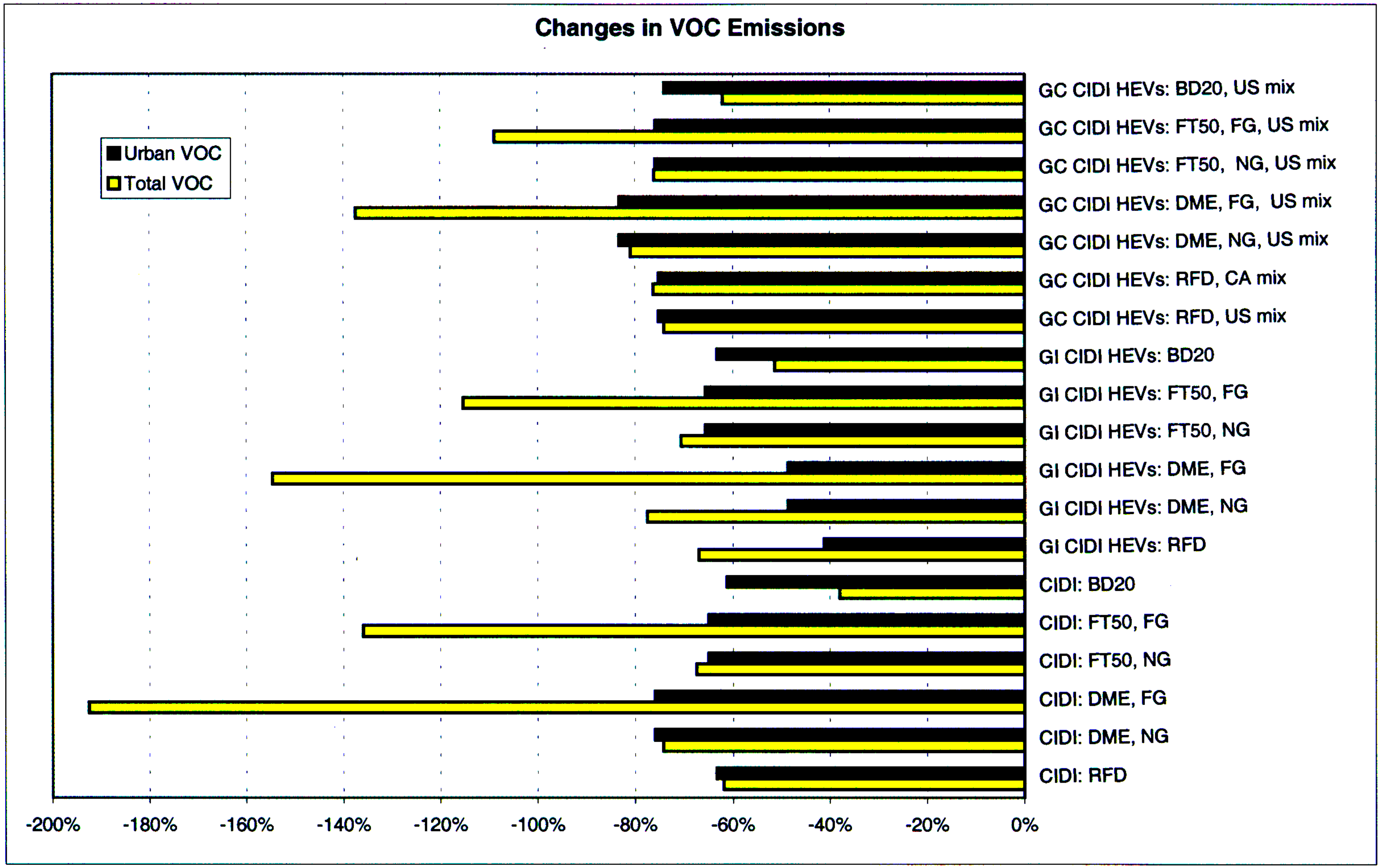
Changes in VOC Emissions

Figure 6.49 Changes in Fuel-Cycle Total and Urban VOC Emissions Relative to GVs Fueled with RFG: Long-Term CIDI Vehicles and CIDI HEVs

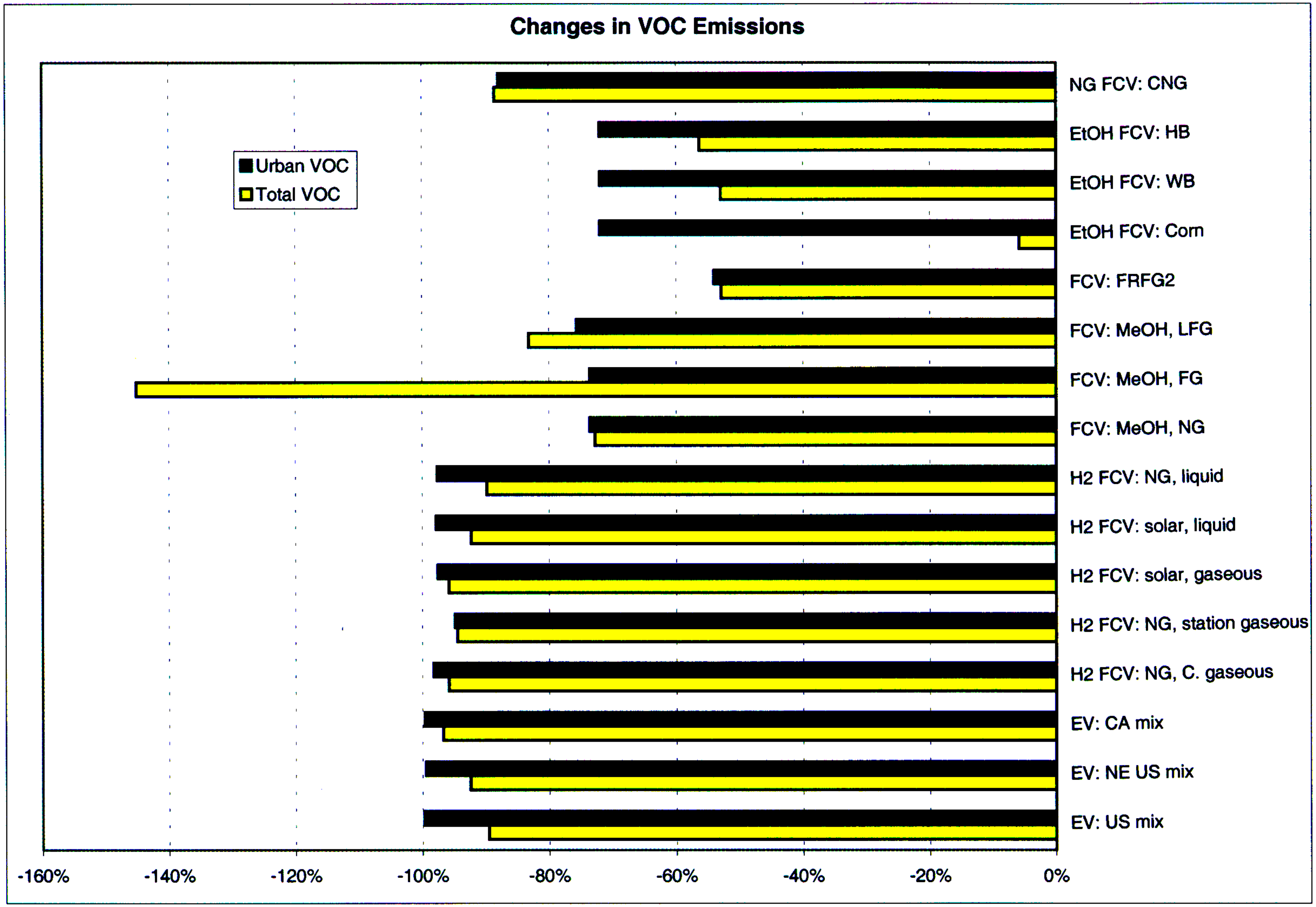

Figure 6.50 Changes in Fuel-Cycle Total and Urban VOC Emissions Relative to GVs Fueled with RFG: Long-Term EVs and FCVs

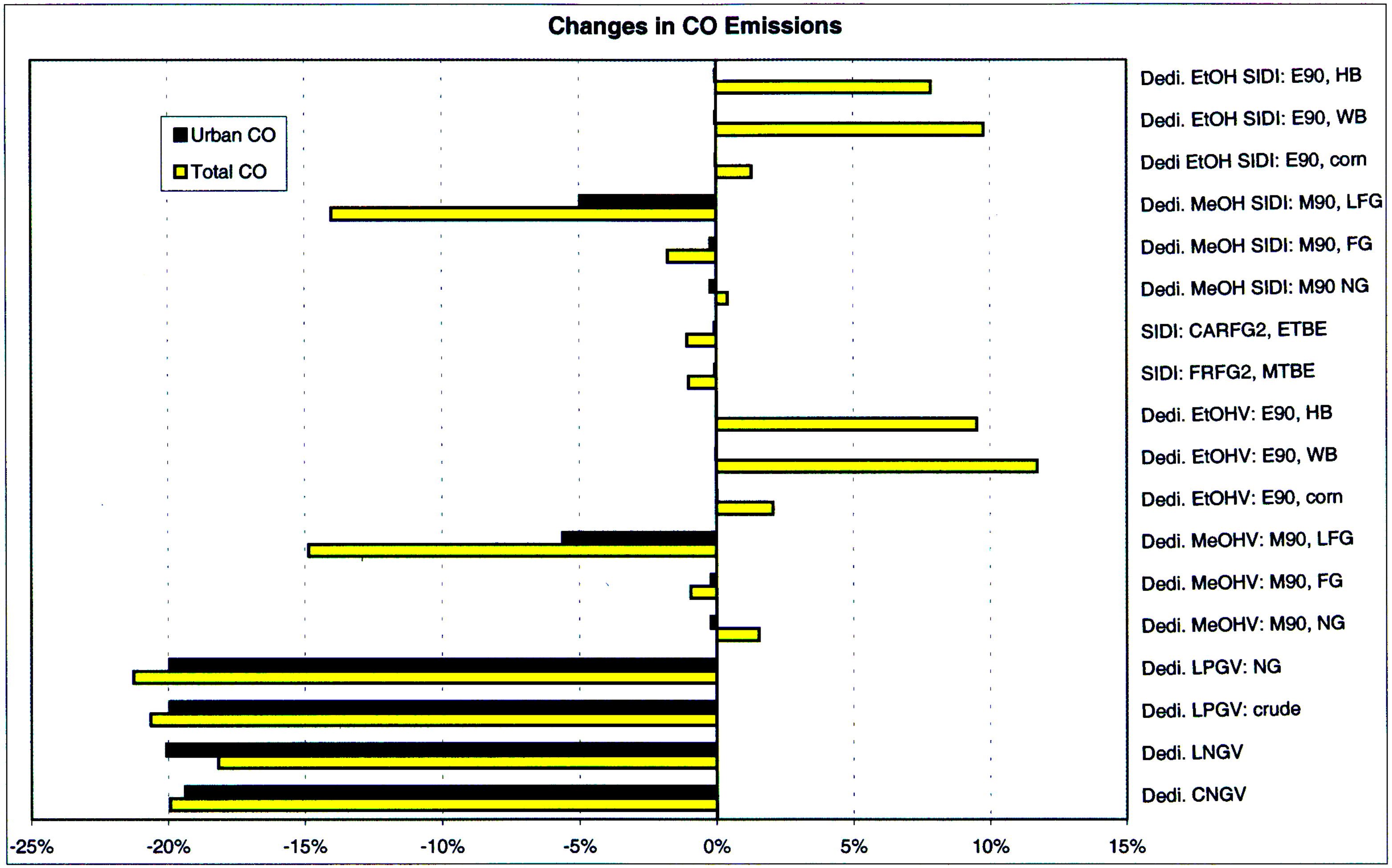

Figure 6.51 Changes in Fuel-Cycle Total and Urban CO Emissions Relative to GVs Fueled with RFG: Long-Term SI and SIDI Vehicles

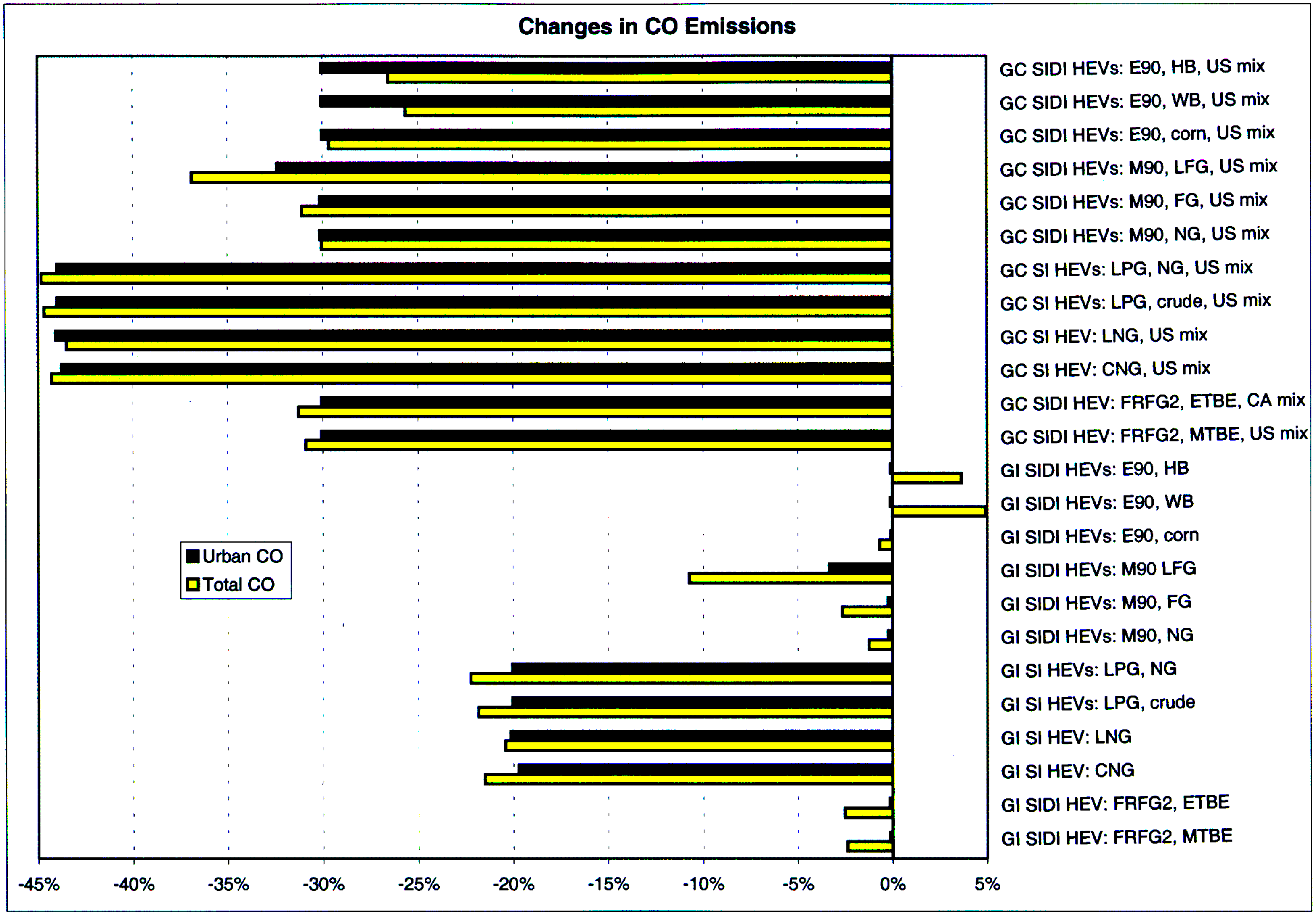

Figure 6.52 Changes in Fuel-Cycle Total and Urban CO Emissions Relative to GVs Fueled with RFG: Long-Term SI and SIDI HEVs

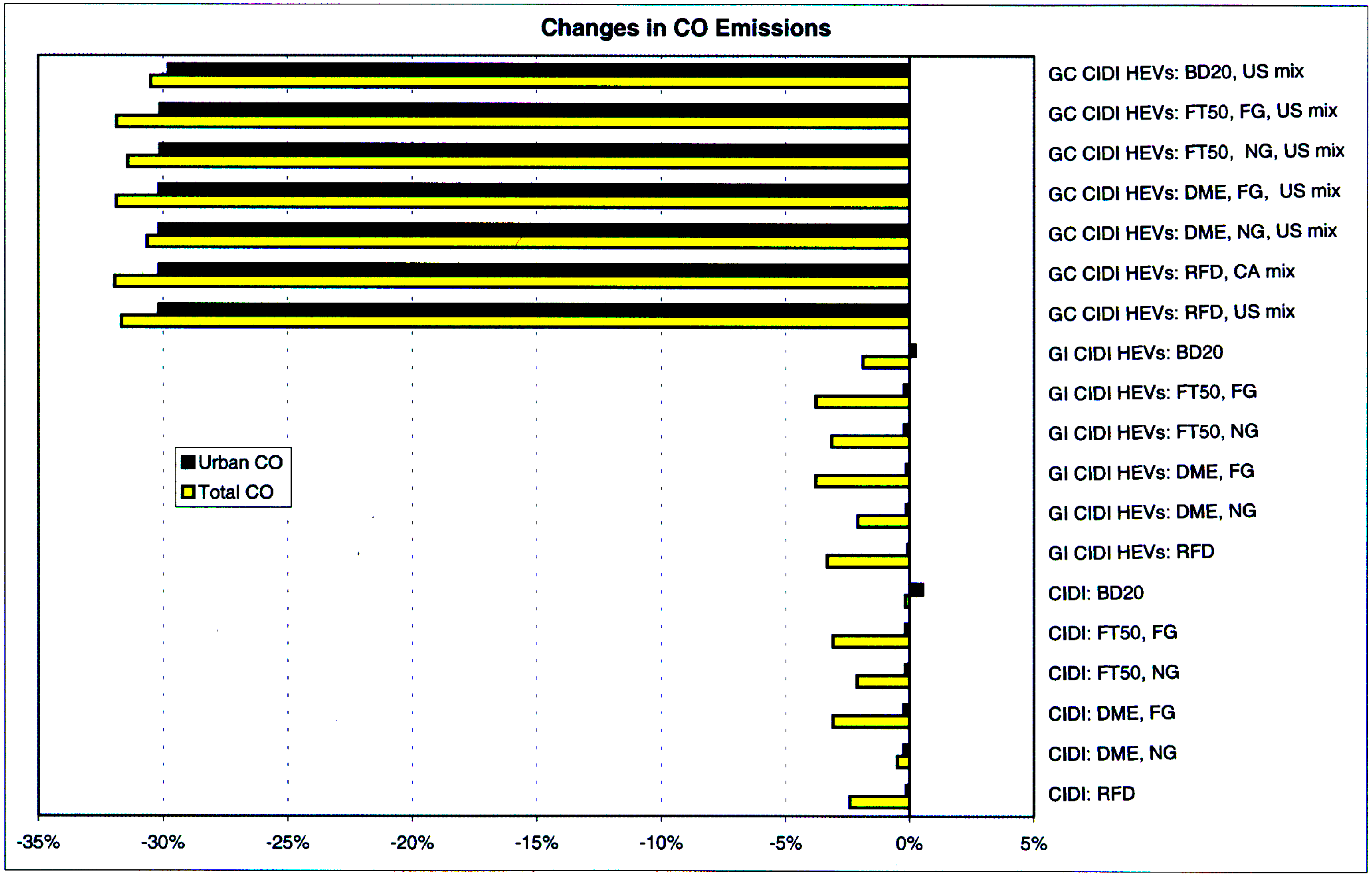

Figure 6.53 Changes in Fuel-Cycle Total and Urban CO Emissions Relative to GVs Fueled with RFG: Long-Term CIDI Vehicles and CIDI HEVs

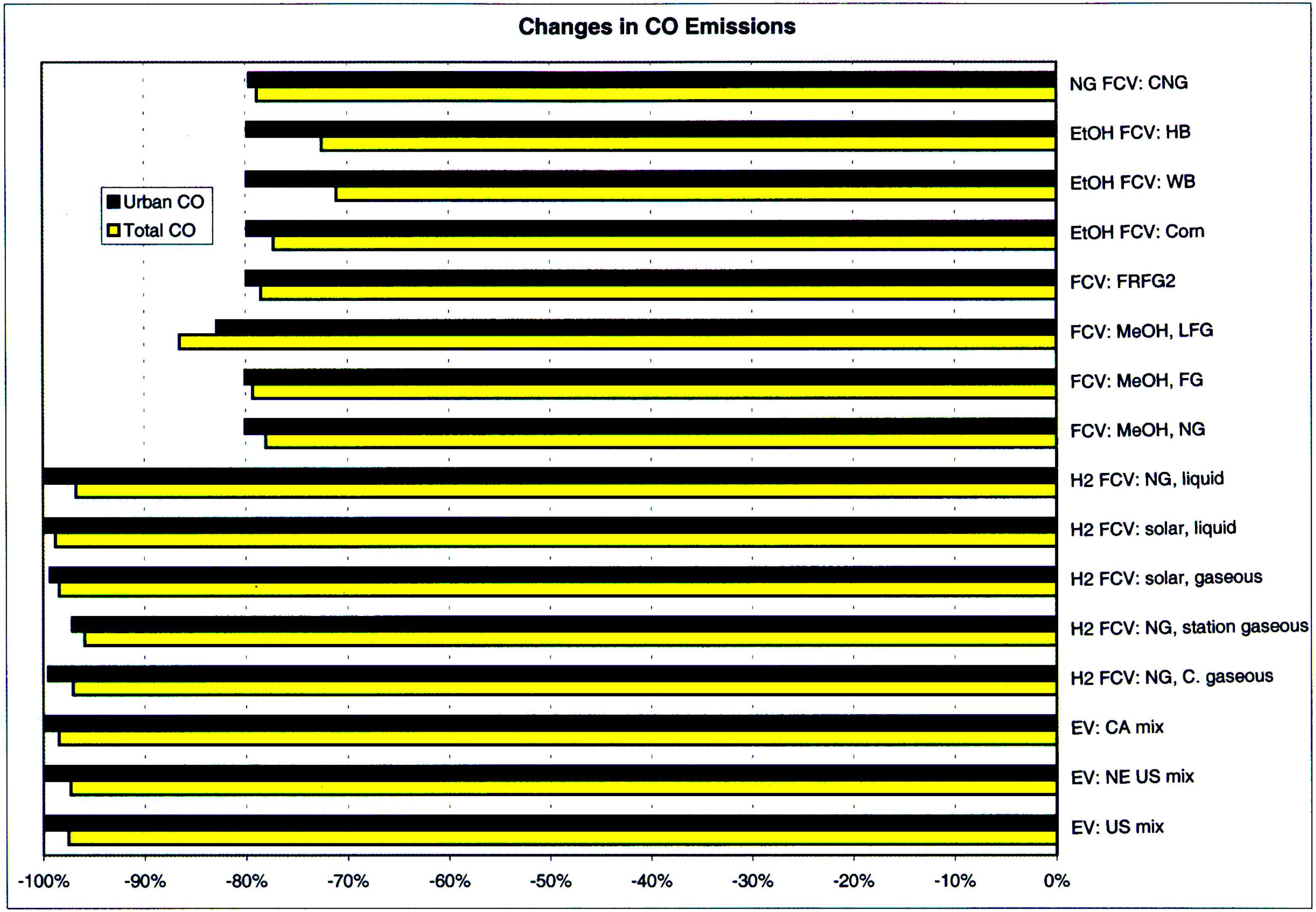

Figure 6.54 Changes in Fuel-Cycle Total and Urban CO Emissions Relative to GVs Fueled with RFG: Long-Term EVs and FCVs

Figure 6.52 shows that use of CNG, LNG, and LPG in SI HEVs achieves 20–40% reductions in total and urban CO emissions. Use of methanol and ethanol has little effect on CO emissions. The figure shows that GC HEVs achieve consistently higher CO emission reductions than GI HEVs.

Figure 6.53 presents CO emission changes for CIDI standalone and hybrid vehicles. Use of CIDI standalone vehicles and CIDI GI HEVs has little effect on CO emissions, especially urban CO emissions. GC HEVs achieve about 30% reductions in CO emissions. The reductions are from the miles traveled on grid electricity for these HEVs. Note that in our GREET simulations (see Section 5), we assume that 30% of the total VMT for GC HEVs are powered by grid electricity.

Figure 6.54 shows CO emission reductions by EVs and FCVs. EVs and H_2-fueled FCVs almost eliminate CO emissions; they are true zero-emission vehicles. FCVs powered with methanol, ethanol, gasoline, and CNG achieve about 80% reductions in CO emissions. The CO emission reductions by these fuels are lower because of emissions associated with on-board fuel processing.

Figures 6.55 through 6.58 present changes in total and urban NO_x emissions for the long-term technology options. Figure 6.55 shows that NO_x emissions for some of the SI and SIDI vehicle options may increase significantly. For example, total NO_x emissions from use of ethanol increase 100–200% because of emissions during farming (tractors and nitrification and denitrification of nitrogen fertilizer) and emissions associated with diesel locomotives and trucks for ethanol transportation and distribution. Use of CNG can result in increased total and urban NO_x emissions caused by emissions from NG compressors in CNG refueling stations (we assumed that one half of the compressors used are electric and the remainder are powered by NG). Use of LNG increases total NO_x emissions, primarily because of emissions from diesel locomotives and diesel trucks used for LNG transportation and distribution. Use of LPG and methanol reduces NO_x emissions slightly. Use of landfill gas-based methanol achieves large reductions because landfill gas burning is eliminated.

Figure 6.56 presents changes in NO_x emissions by SI and SIDI HEVs. The general patterns in NO_x emissions for these vehicle options are similar to those for SI and SIDI vehicles (as shown in Figure 6.55). That is, use of ethanol could increase total NO_x emissions and use of CNG could lead to increased urban NO_x emissions. For other fuels such as LPG, methanol, and RFG, use of HEVs results in moderate reductions in NO_x emissions. Large reductions are achieved with use of flared gas- and landfill gas-based methanol. Use of GC HEVs achieves greater NO_x emission reductions than use of GI HEVs.

Figure 6.57 shows changes in NO_x emissions by CIDI vehicles and CIDI HEVs. In general, these vehicle options have higher urban NO_x emissions than baseline GVs, except GC HEVs, which generate NO_x emissions at levels similar to those of baseline GVs. Most vehicle options reduce total NO_x emissions because the amount of emissions from petroleum refining is larger than the amount from producing these CI fuels.

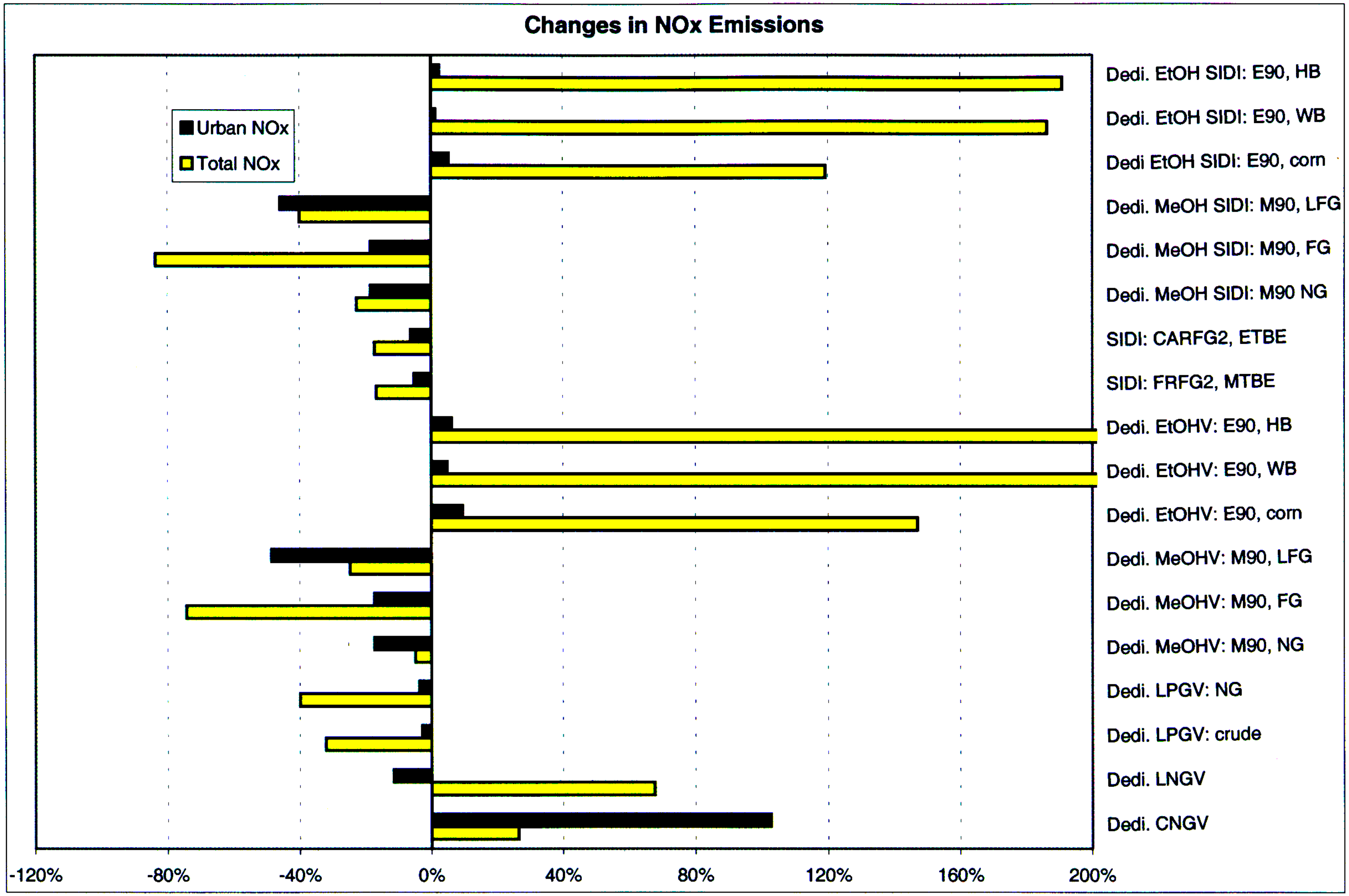

Figure 6.55 Changes in Fuel-Cycle Total and Urban NO_x Emissions Relative to GVs Fueled with RFG: Long-Term SI and SIDI Vehicles

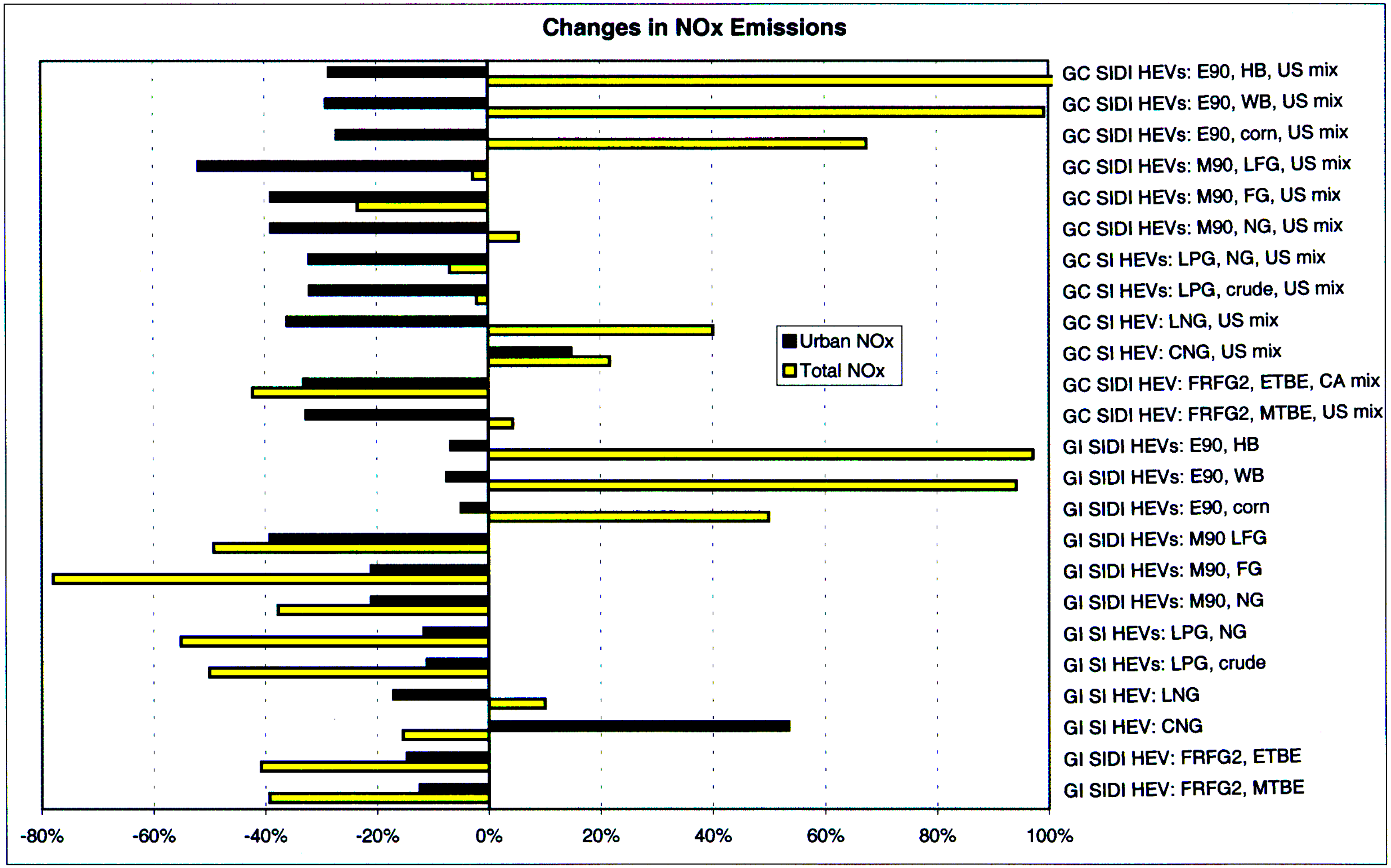

Figure 6.56 Changes in Fuel-Cycle Total and Urban NO_x Emissions Relative to GVs Fueled with RFG: Long-Term SI and SIDI HEVs

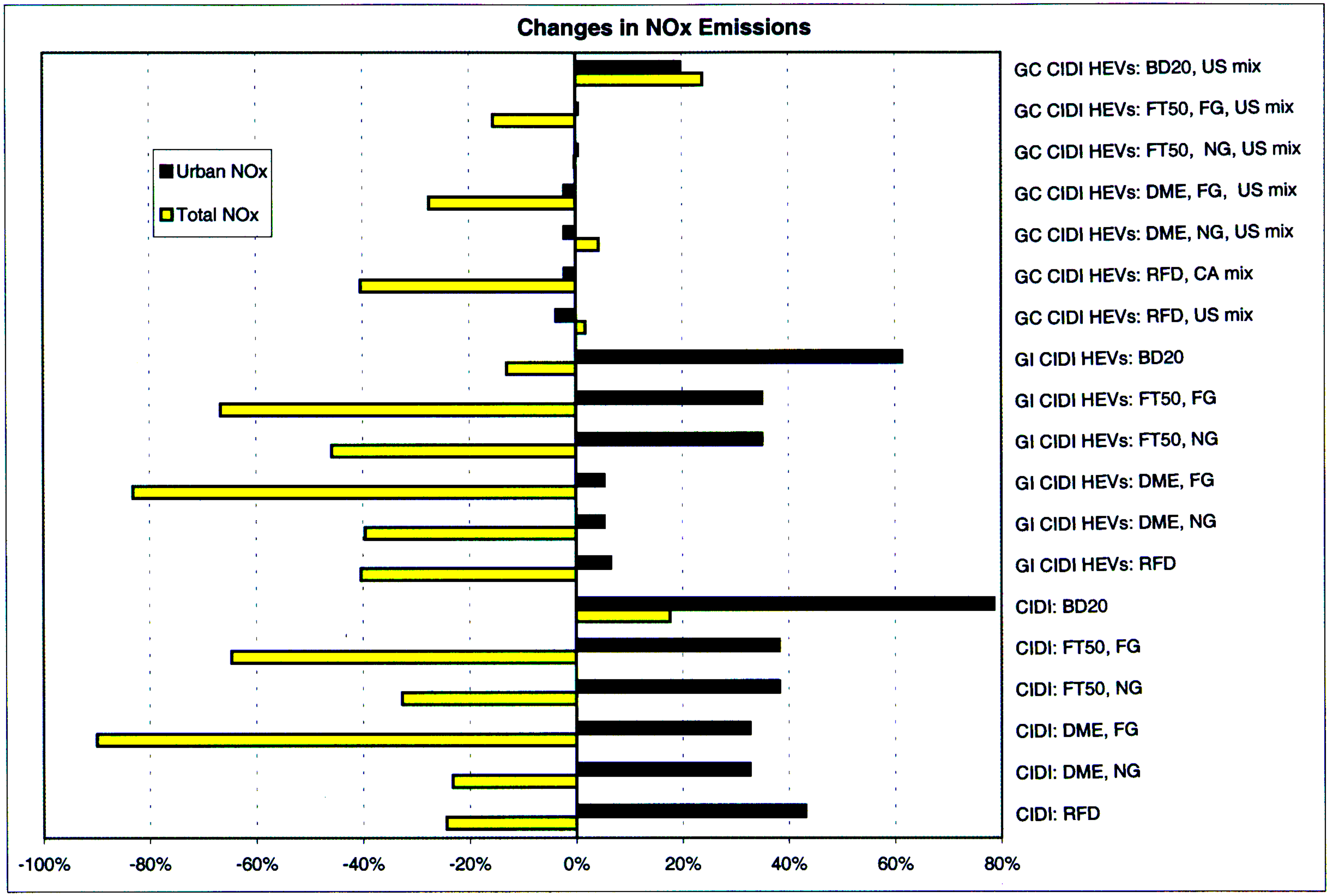

Figure 6.57 Changes in Fuel-Cycle Total and Urban NO_x Emissions Relative to GVs Fueled with RFG: Long-Term CIDI Vehicles and CIDI HEVs

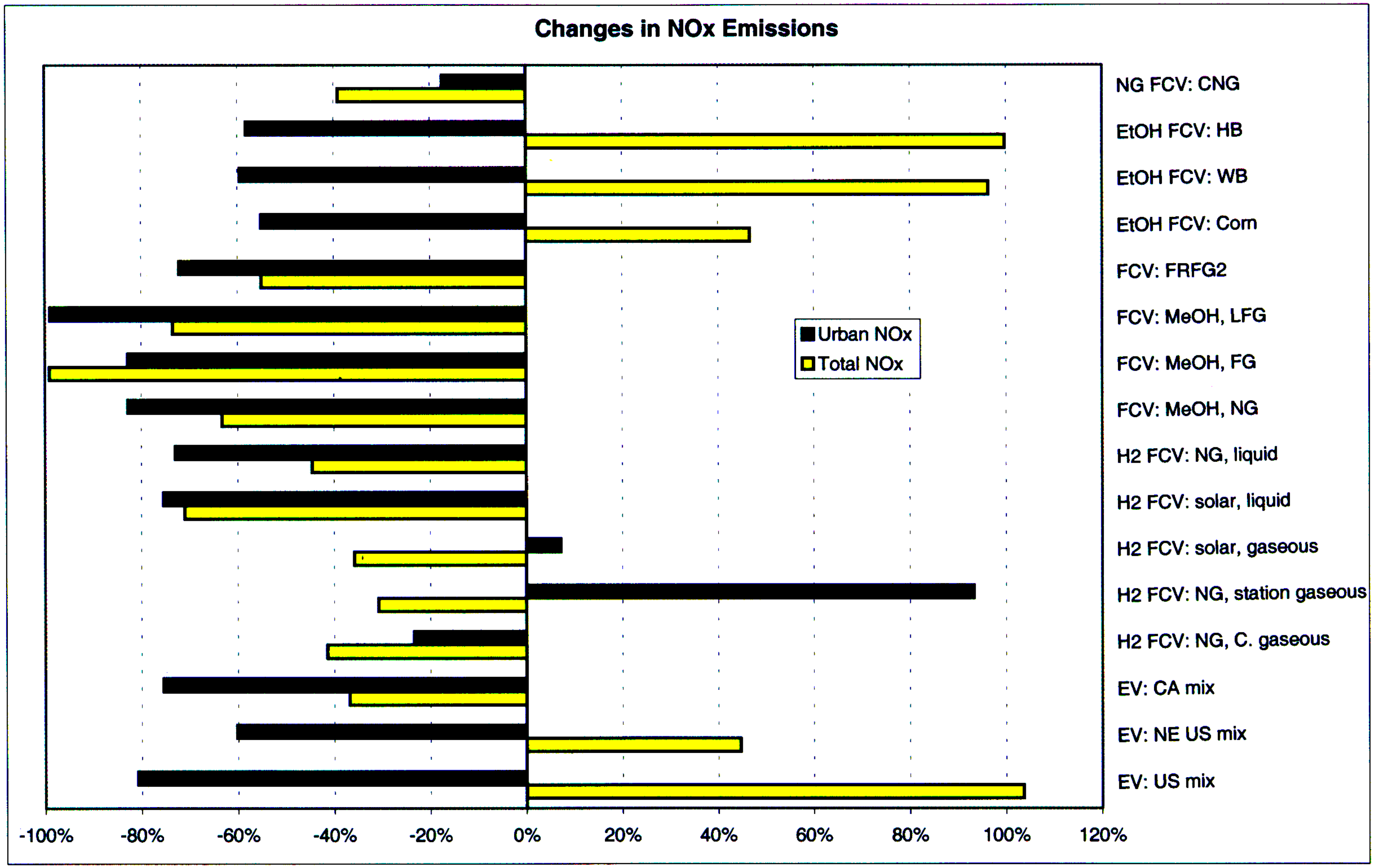

Figure 6.58 Changes in Fuel-Cycle Total and Urban NO_x Emissions Relative to GVs Fueled with RFG: Long-Term EVs and FCVs

Figure 6.58 presents changes in NO_x emissions for EVs and FCVs. With the U.S. and Northeast U.S. electric generation mix, use of EVs results in increases in total NO_x emissions, but decreases in urban NO_x emissions. With the California generation mix, EVs reduce both total and urban NO_x emissions. Of the FCV options, use of H_2 produced from NG at refueling stations (decentralized H_2 production) results in increases in urban emissions, because NO_x emissions from H_2 production at refueling stations occurs within urban areas. Use of ethanol increases total NO_x emissions because of high NO_x emissions during farming and ethanol production. Use of other fuels can achieve 60–80% reductions in urban NO_x emissions.

The results of changes in NO_x emissions demonstrate the increased importance of upstream emissions as regulations for vehicle tailpipe emissions are tightened. Even for clean vehicle technologies, such as CNGVs and H_2-fueled FCVs, urban NO_x emissions can be increased if the fuel used is produced within urban areas. Readers need to keep in mind that NO_x emissions from fuel production and compression calculated in GREET are estimated on the basis of current information, assumptions of the split between electric and gas compressors, and estimated emissions from gas compressors. When new information becomes available, the NO_x emission results could be different.

Figures 6.59 through 6.62 present changes in total and urban PM_{10} emissions for the long-term options. Note that vehicular PM_{10} emissions include tire- and brake-wear emissions as well as exhaust emissions. In fact, as tailpipe PM_{10} emissions are reduced (as more stringent PM standards for vehicles take effect), tire- and brake-wear emissions will account for a large share of total vehicle PM_{10} emissions. As Figure 6.59 shows, use of landfill gas-based methanol in SI and SIDI engines results in huge reductions in total and urban PM_{10} emissions because production of methanol from landfill gas eliminates PM_{10} emissions from landfill gas burning. On the other hand, use of corn-based ethanol causes large increases in total PM_{10} emissions (although urban PM_{10} emissions are reduced). The large increases are primarily caused by PM_{10} emissions during tillage for corn farming. Also, total PM_{10} emissions are increased to some extent by use of cellulosic ethanol. Use of CNG, LNG, LPG, and methanol from natural gas and flared gas results in moderate reductions in both total and urban PM_{10} emissions.

Figure 6.60 shows changes in PM_{10} emissions for SI and SIDI HEVs. The change patterns with these vehicles types are similar to those for SI and SIDI stand-alone applications (Figure 6.59).

Figure 6.61 presents changes in total and urban PM_{10} emissions for CIDI standalone and hybrid applications. As presented in Table 6.5, we assumed that passenger cars fueled with RFD will meet the PM standard of 0.01 g/mi for Tier 2 Bin 4, the same standard to which Tier 2 gasoline cars will be subject under Tier 2 Bin 3. Consequently, tailpipe PM_{10} emissions for gasoline engines and diesel engines are the same (see Table 6.4). Automakers are currently conducting intensive research and development to reduce diesel engine PM_{10} emissions. While it is conceivable for diesel cars to achieve PM_{10} emissions comparable to those of gasoline cars, diesel engines will face a tough challenge to reduce PM_{10} emissions to that level. On the other hand, we assumed that diesel LDT1 and LDT2 will meet the PM_{10} standard of 0.02 g/mi. Thus, diesel LDT1 and LDT2 will have PM_{10} emissions higher than those of gasoline LDT1 and

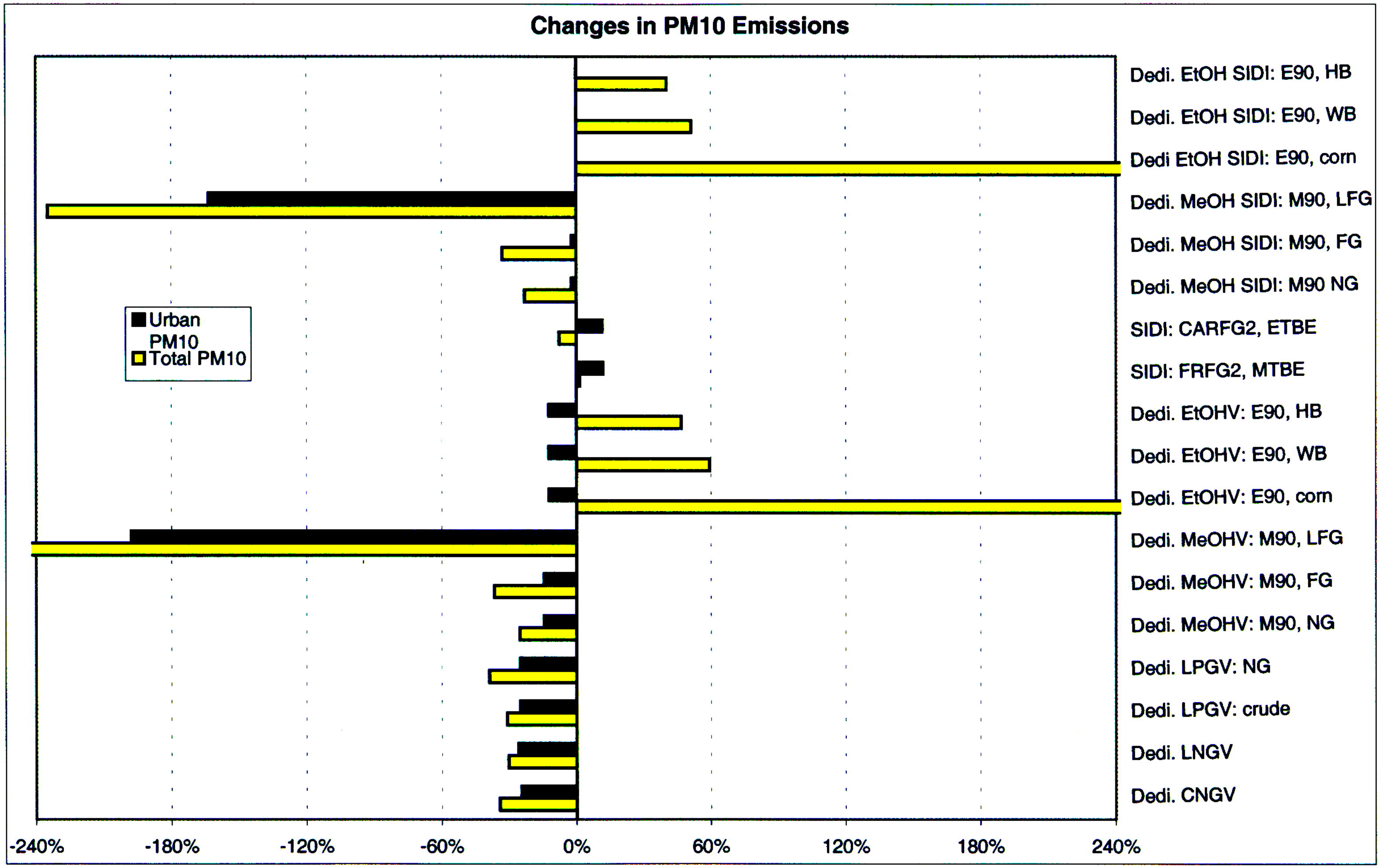

Figure 6.59 Changes in Fuel-Cycle Total and Urban PM_{10} Emissions Relative to GVs Fueled with RFG: Long-Term SI and SIDI Vehicles

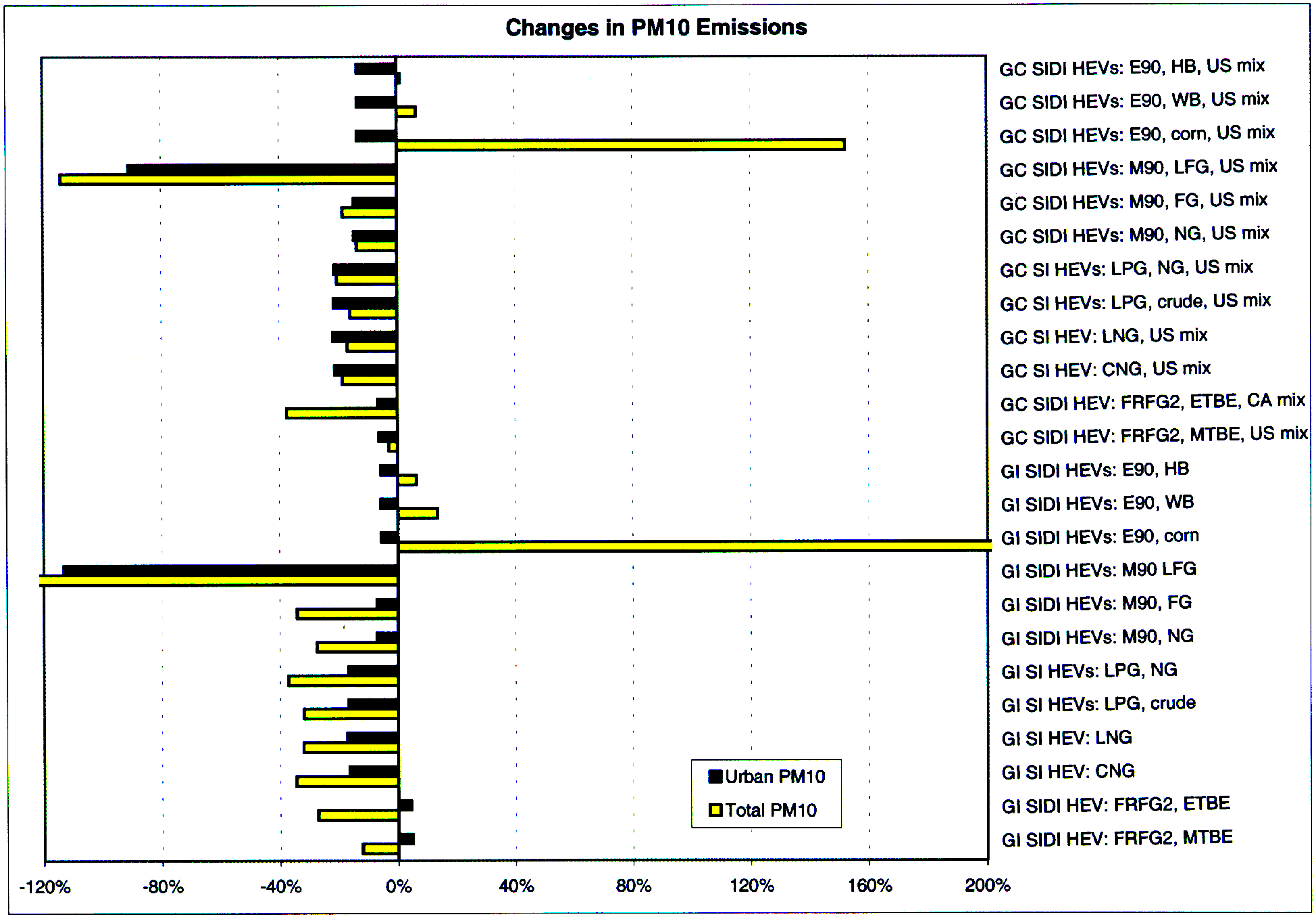

Figure 6.60 Changes in Fuel-Cycle Total and Urban PM$_{10}$ Emissions Relative to GVs Fueled with RFG: Long-Term SI and SIDI HEVs

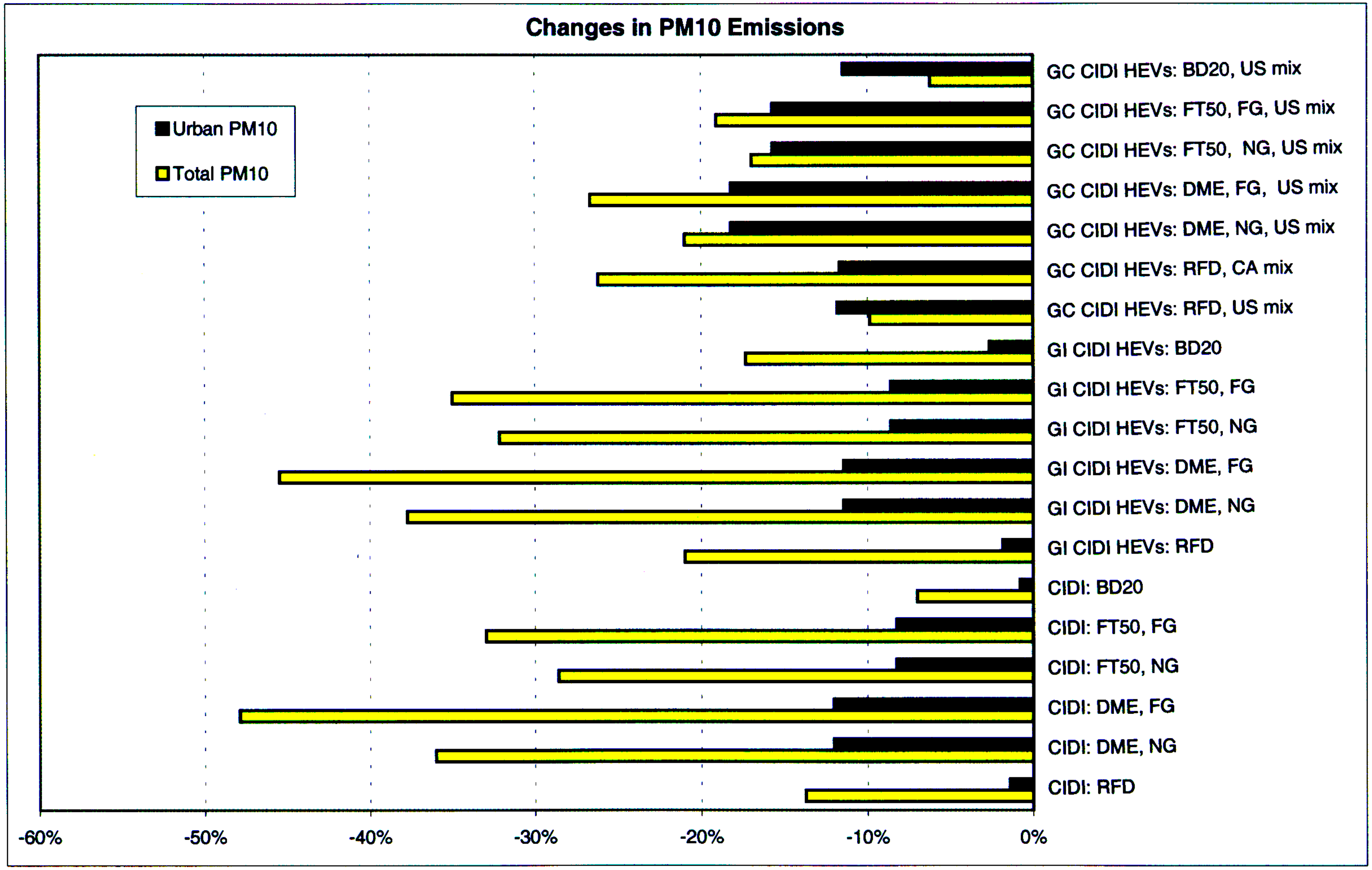

Figure 6.61 Changes in Fuel-Cycle Total and Urban PM_{10} Emissions Relative to GVs Fueled with RFG: Long-Term CIDI Vehicles and CIDI HEVs

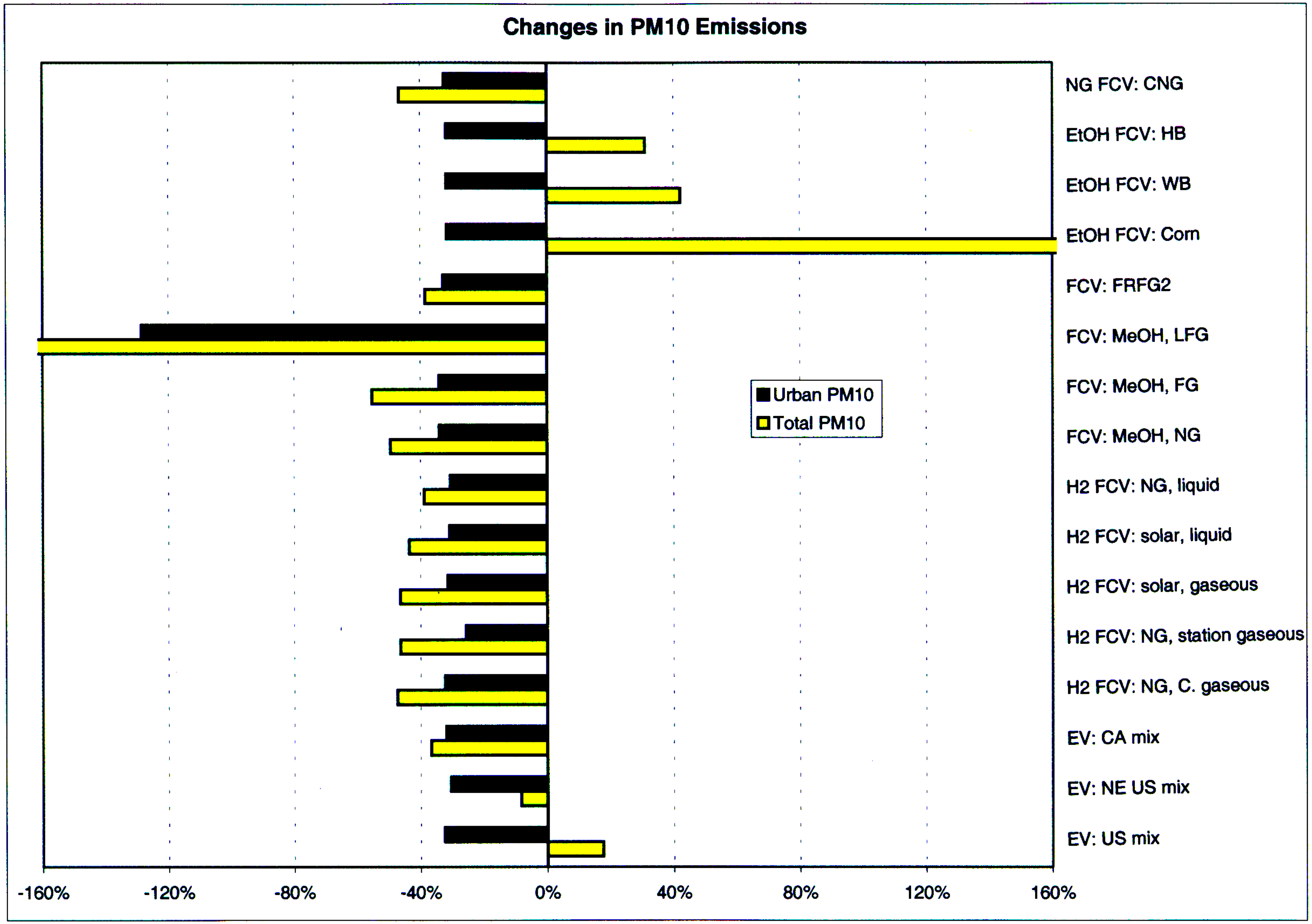

Figure 6.62 Changes in Fuel-Cycle Total and Urban PM_{10} Emissions Relative to GVs Fueled with RFG: Long-Term EVs and FCVs

LDT2, respectively. As Figure 6.61 shows, the CIDI vehicle technologies fueled by RFD, DME, FT50, and BD20 reduce both total and urban PM_{10} emissions. Urban PM_{10} emission reductions are 10–20% for most options.

Figure 6.62 shows PM_{10} emission reductions by EVs and FCVs. Total PM_{10} emissions are increased by use of EVs with the U.S. average electric generation mix and by use of ethanol-fueled FCVs. The increases are caused by high PM_{10} emissions in coal-fired power plants (over 50% of electricity is generated from coal in the United States) and from tillage during corn farming for ethanol. On the other hand, use of landfill gas-based methanol in FCVs results in huge PM_{10} emission reductions because PM_{10} emissions generated by landfill gas burning are eliminated. Other fuel options achieve 30–40% reductions in PM_{10} emissions.

Overall, reductions in PM_{10} emissions by new fuels and advanced vehicle technologies are smaller than researchers might expect, primarily because vehicle tire- and brake-wear PM emissions are included in GREET calculations. Vehicles within the same class have similar tire- and brake-wear emissions, which dilutes the effects of the fuels and vehicle technologies.

Figures 6.63 through 6.66 present total and urban SO_x emission changes for the long-term technologies. Figure 6.63 shows the results for SI and SIDI vehicles. Total SO_x emissions are noticeably increased by use of landfill gas-based methanol and corn-based ethanol. The increase for methanol is caused by the significant amount of electricity used for landfill gas-to-methanol production. Electricity generation produces SO_x emissions outside of urban areas, which is why landfill gas-based methanol still achieves a huge reduction in urban SO_x emissions. For corn-based ethanol, the increased SO_x emissions are the result of coal combustion in ethanol plants. Use of other fuel options generally results in over-80% reductions in urban SO_x emissions, except for RFG used in SIDI engines, where a moderate 20% reduction results from SIDI’s improved fuel economy.

Figure 6.64 presents changes in SO_x emissions for SI and SIDI HEVs. For total SO_x emissions, GC HEVs with the U.S. electric generation mix produce higher emissions than GI HEVs because of high SO_x emissions from coal-fired electric power plants. On the other hand, all the fuel and vehicle options achieve over-80% reductions in urban SO_x emissions, except for RFG, which achieves moderate reductions of 40–60%.

Figure 6.65 shows SO_x emission changes for CIDI vehicles and CIDI HEVs. GC HEVs have higher total SO_x emissions than GI HEVs or CIDI vehicles. Urban SO_x emissions from RFD-fueled CIDI vehicles are a little higher than those from baseline GVs. For urban SO_x emissions, use of DME achieves the largest reduction because DME does not contain sulfur. On the other hand, FT50 and BD20, which contain RFD, account for some SO_x emissions.

As Figure 6.66 shows, EVs and FCVs reduce urban SO_x emissions by over 90%. Total SO_x emissions are increased by EVs with the U.S. and Northeast U.S. electric generation mix because of SO_x emissions from coal and oil-fired electric power plants. Total SO_x emissions are increased by corn-based ethanol in FCVs because of SO_x emissions associated with coal combustion in ethanol plants.

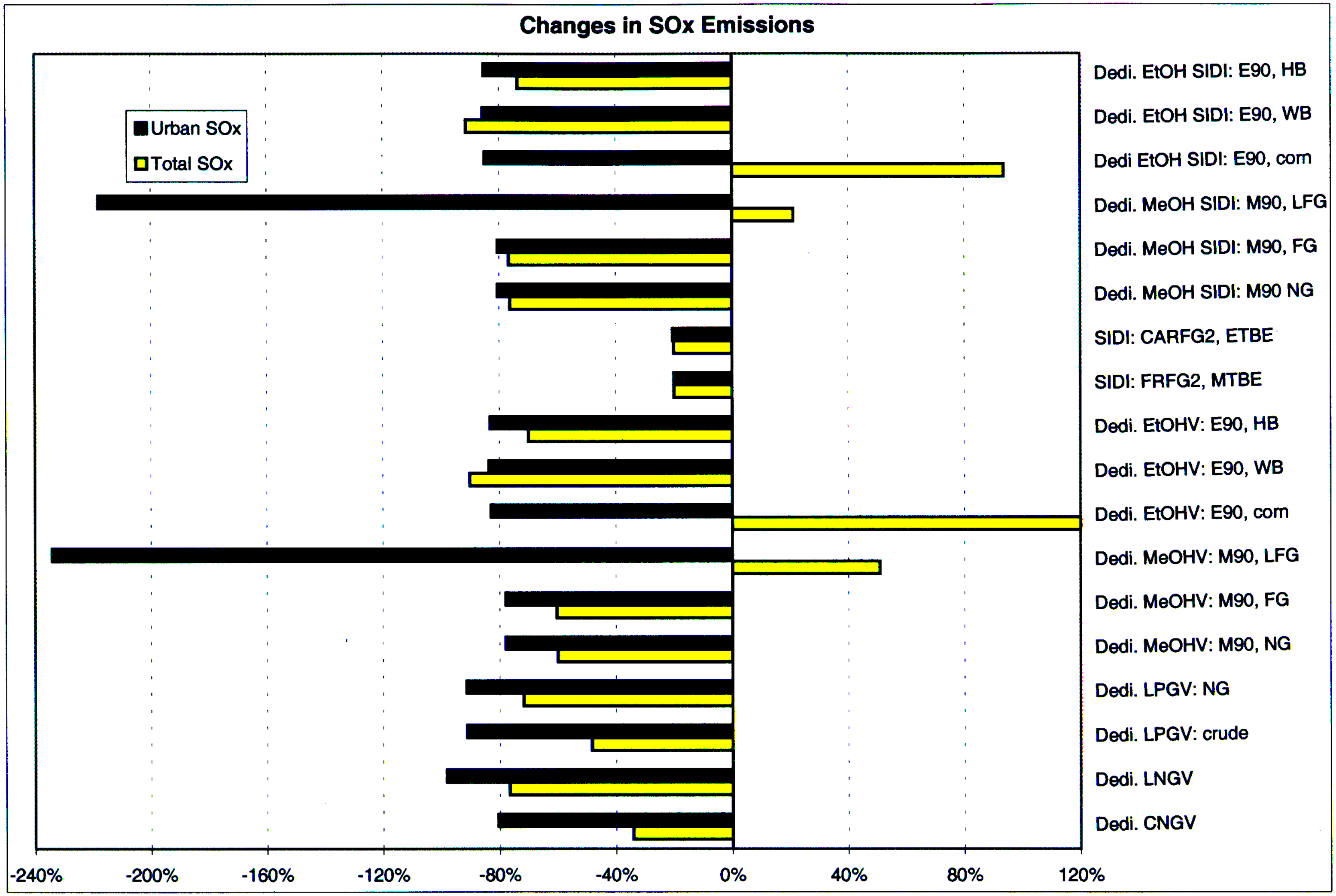

Figure 6.63 Changes in Fuel-Cycle Total and Urban SO_x Emissions Relative to GVs Fueled with RFG: Long-Term SI and SIDI Vehicles

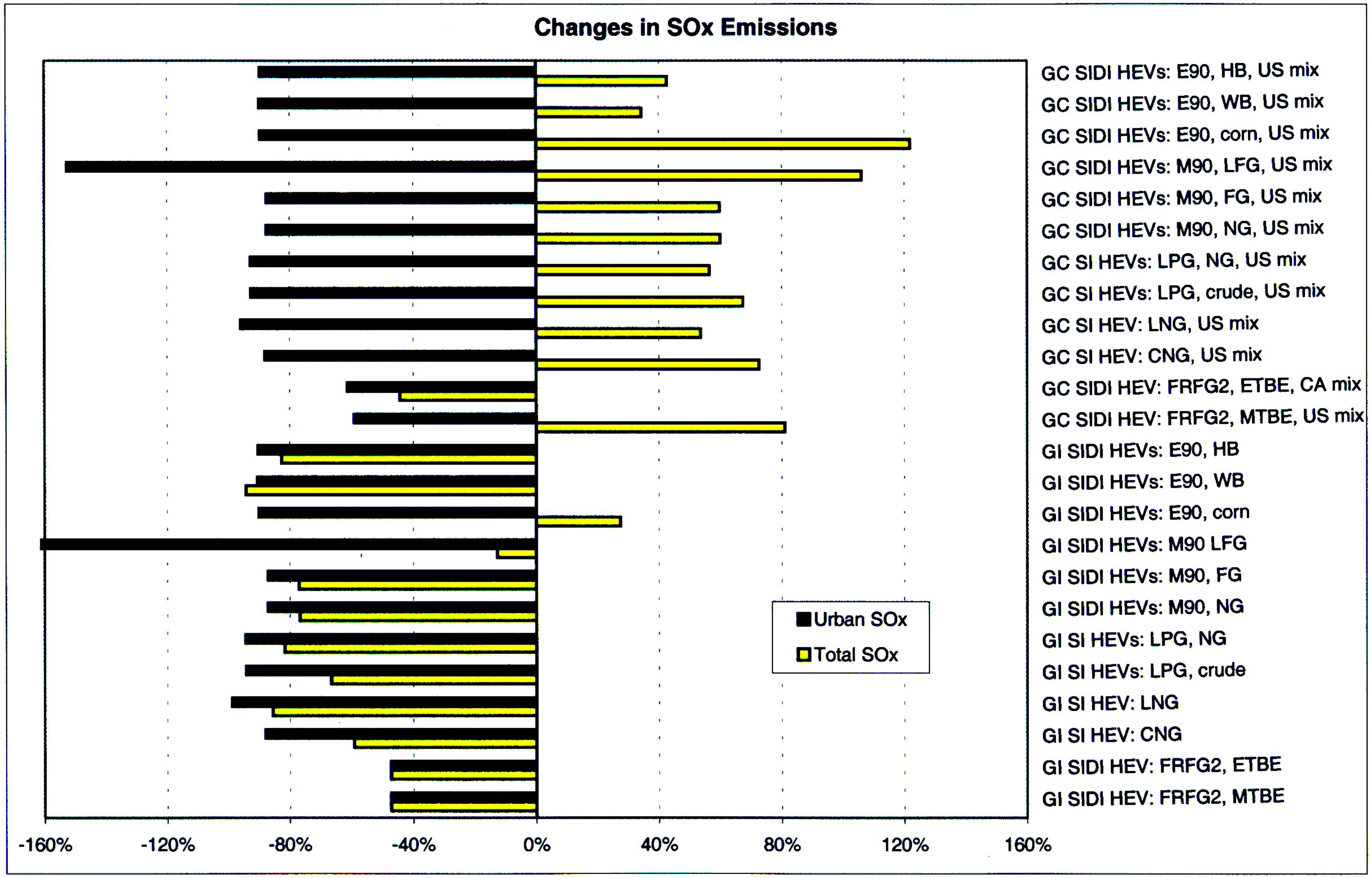

Figure 6.64 Changes in Fuel-Cycle Total and Urban SO_x Emissions Relative to GVs Fueled with RFG: Long-Term SI and SIDI HEVs

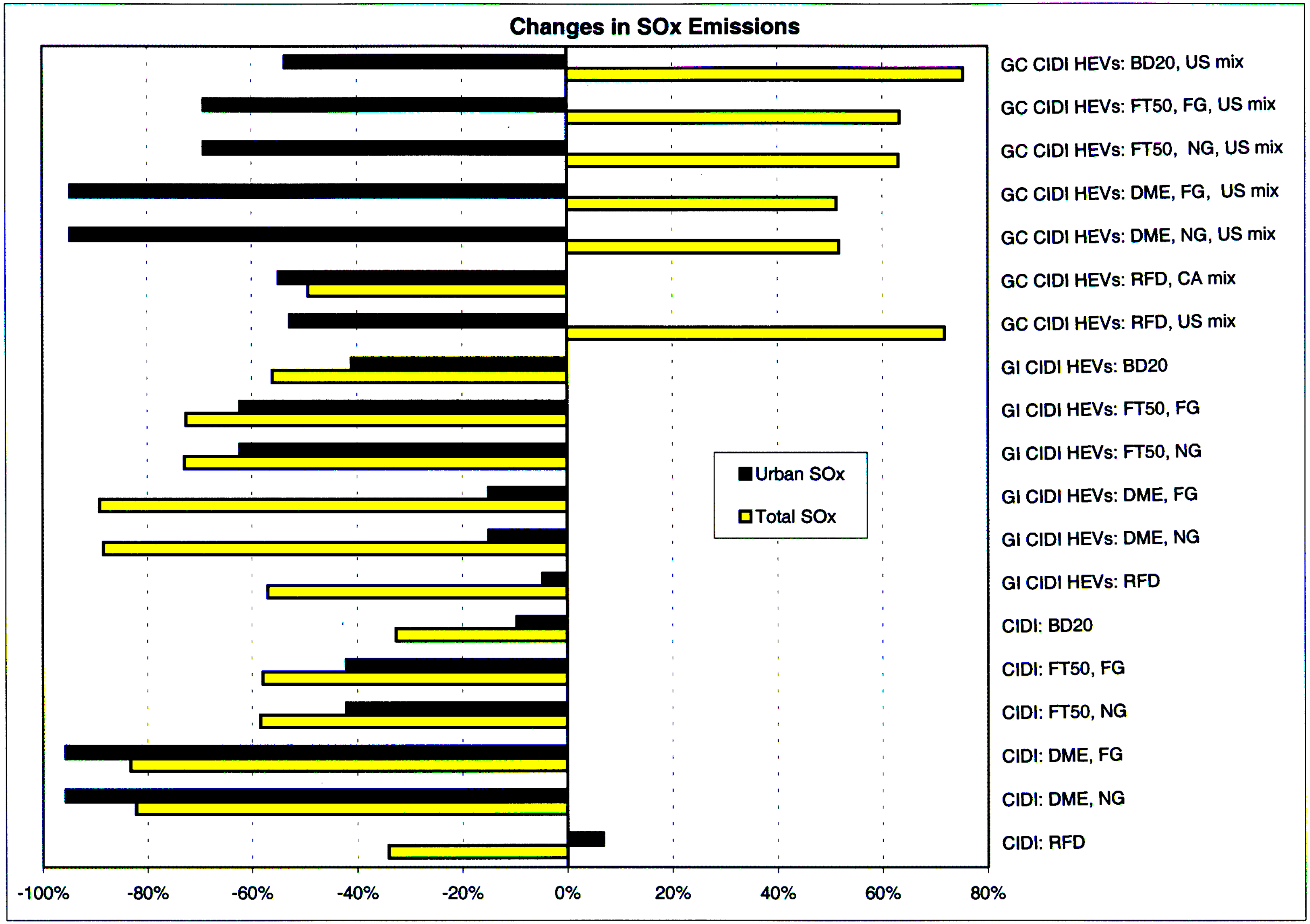

Figure 6.65 Changes in Fuel-Cycle Total and Urban SO$_x$ Emissions Relative to GVs Fueled with RFG: Long-Term CIDI Vehicles and CIDI HEVs

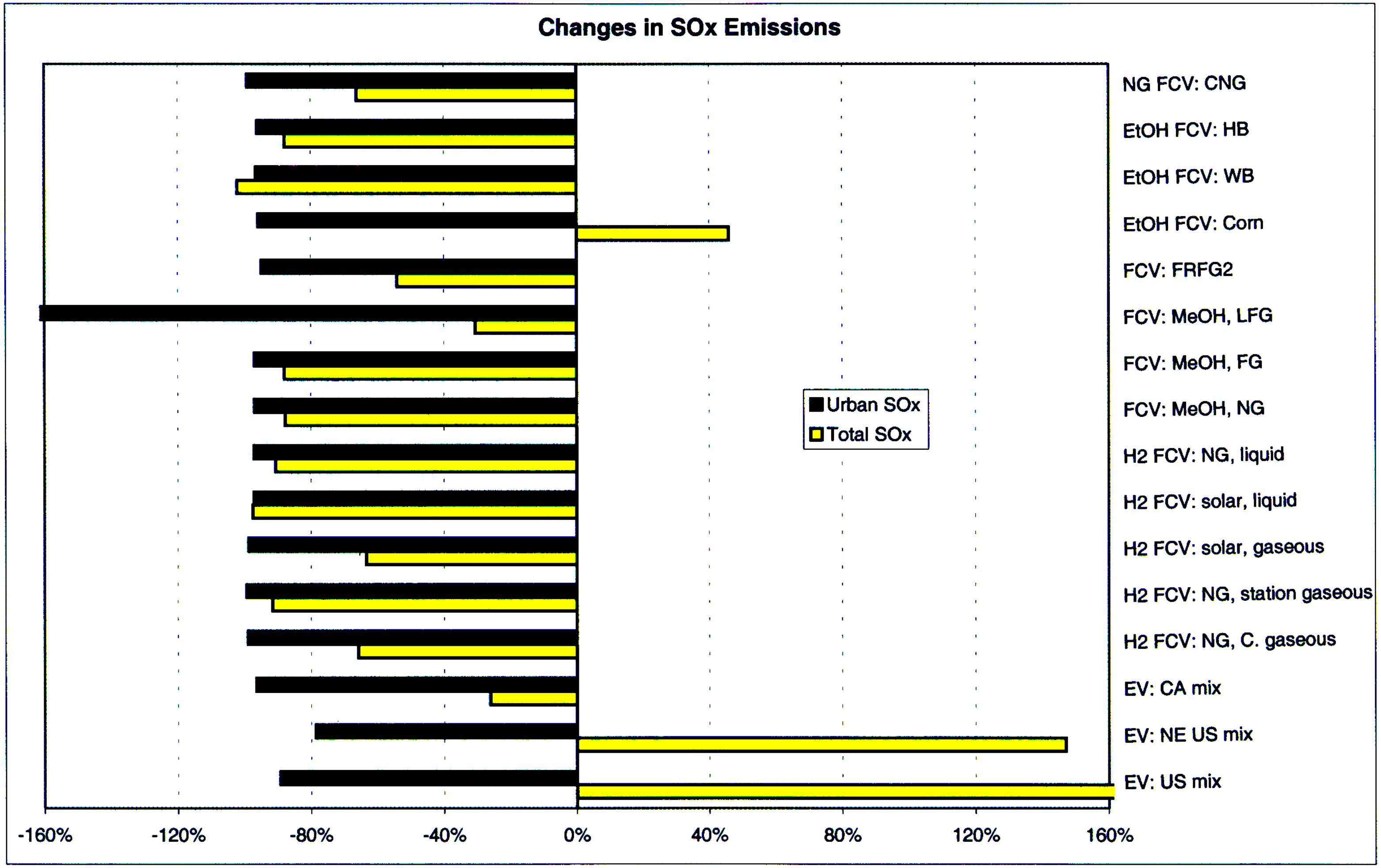

Figure 6.66 Changes in Fuel-Cycle Total and Urban SO_x Emissions Relative to GVs Fueled with RFG: Long-Term EVs and FCVs

6.5 Summary

Of the near- and long-term fuels and vehicle technologies evaluated in this study, the near-term technologies offer smaller energy and emission benefits than do the long-term technologies, especially with respect to energy use and GHG emissions. For emissions of criteria pollutants, the baseline GVs for the long-term technologies were assumed to meet the proposed federal Tier 2 vehicle emission standards. Although emission reductions by long-term alternative fuels and advanced technologies are relatively large in percentages, per-mile emission reductions achieved by long-term technologies are smaller than those achieved by near-term technologies.

Long-term technologies offer great energy and emission benefits, but most of them are not ready for commercial use. The market viability of these technologies will depend very much on the success of research and development efforts to overcome their technological hurdles. Evaluating the market readiness of these technologies is beyond the scope of this study.

Most of the technology options analyzed in this report have tradeoffs among energy use, emissions of GHGs, and emissions of criteria pollutants. That is, there is no single technology or technology/fuel combination — no “silver bullet” — that solves energy, GHG emissions, and urban pollution problems. One technology may have positive energy and GHG emission impacts but adverse urban air pollution impacts. Considering the tradeoffs and uncertainties in market viability of these technologies, it may be necessary to pursue multiple technology pathways to achieve energy, GHG emissions, and urban air pollution benefits for the transportation sector.

GREET is a fuel-cycle model based on conventional fuel-cycle analysis methodologies and approaches. The model addresses technological potentials of energy and emission impacts of given transportation fuels and technologies. As a new transportation technology is introduced into the marketplace, it could affect the use of existing technologies through some market mechanisms. That is, while energy and emission changes, as calculated in GREET, are based on mile-for-mile displacement between a new technology and the existing technology, the displacement in the real world may not be on a mile-for-mile ratio. Although the market effects of a few issues (such as land use changes from increased production of corn ethanol, coproducts of corn ethanol, and electricity credits of cellulosic ethanol) are addressed in GREET, the effects are generally beyond GREET’s modeling capability.

The results of our study represent our estimates of fuel-cycle energy and emission impacts of new technologies based on our own best judgments of technology advances over time. By nature, the evaluated technology options, especially the more speculative long-term technology options, are subject to uncertainties. These uncertainties will undoubtedly affect the outcomes of fuel-cycle assessments. For a given technology, we could have run the GREET model using different sets of assumptions to provide a range of estimates. However, because of the large number of technology options involved in this study and because our resources are limited, we were unable to conduct such a series of simulations using the GREET model. The results presented here provide a “snapshot” of potential technology effects based on our current understanding of technology advancements. As more information becomes available for new technologies, we will revise key assumptions in the GREET model regularly, and the results will change. Preferably, readers will study the assumptions used in this study, develop their own assumptions, and use those assumptions in the GREET model to generate their own results.

Section 7
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