# Renewable Fuel Standard Program (RFS2) Regulatory Impact Analysis

United States
Environmental Protection
Agency

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Assessment and Standards Division
Office of Transportation and Air Quality
U.S. Environmental Protection Agency

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# Statement of Need

The original Renewable Fuel Standard (RFS) program was adopted by EPA to implement the provisions of the Energy Policy Act of 2005 (EPAct), which added section 211(o) to the Clean Air Act (CAA). With the passage of the Energy Independence and Security Act of 2007 (EISA), Congress made several important revisions to the renewable fuel requirements. This rule revises the RFS program regulations to implement these EISA provisions.

# Overview

The displacement of gasoline and diesel with renewable fuels has a wide range of environmental and economic impacts. This Regulatory Impact Analysis (RIA) utilizes case study approaches to assess the impacts of an increase in production, distribution, and use of the renewable fuels sufficient to meet the RFS2 volumes established by Congress in the Energy Independence and Security Act of 2007 (EISA). This reflects our updated assessment compared to the draft RIA conducted in support of the Notice of Proposed Rulemaking (NPRM). Because the standards were mandated by Congress in EISA, the impacts we are assessing are not being used to justify or support the decisions for the RFS2 volume standards, but rather to provide an assessment of the projected impacts of these standards when fully implemented. This information can then be used in future public policy decisions. As explained below, the estimates contained in this RIA should not be interpreted as the impact of the RFS2 standards themselves because market forces may lead to increased production of renewable fuels even in the absence of the RFS2 standards. Rather, the impacts estimated in this RIA must be understood to refer to the consequences of an expansion of renewable fuel use, whether caused by the RFS2 program or by market forces.

The analytical approach taken by EPA in this RIA is to predict what the world would be like, in terms of a range of economic and environmental factors, if renewable fuel use increases to the level required by the RFS2 standards. We then compare this to two reference cases without the RFS2 progam. The primary reference case is a projection made prior to EISA by the US Energy Information Administration (EIA) in their 2007 Annual Energy Outlook (AEO2007) of renewable fuel volumes that would have been expected in 2022 (13.56 billion gallons). We then combined this with AEO2009 energy consumption and cost estimates. While AEO2007 is not as up-to-date as AEO2009, we could not use later projections by EIA for renewable fuel use because they already include the impact of the RFS2 standards as required by EISA as well as fuel economy improvements under CAFE as required in EISA. Upon completion of our fuel cost analyses as described in Chapter 4, however, it became apparent that by 2022, we are projecting that renewable fuel production costs will decline and crude oil prices rise to the point that renewable fuels are less expensive than gasoline and diesel fuel, even in the absence of any tax subsidies. One of the primary drivers for this is the fact that AEO2009 projects $116 per barrel of crude oil in 2022 (instead of the $53 per barrel projection in AEO2007). This implies that market forces will lead to a greater increase in renewable fuel volumes than was projected in AEO2007, even in the absence of the RFS2 standards.

However, it is difficult to estimate the extent to which these market forces, in the absence of the RFS2 standards, would indeed spur investments to increase renewable fuel production and usage. Given the magnitude of the capital investment needed for the RFS2 renewable fuel volumes, the risk associated with these investments due to the fact that for the bulk of the volume we are relying on new cellulosic biofuel technology, and the uncertainty in future crude oil prices, market forces alone may result in a level of investment insufficient to achieve the renewable fuel volumes mandated by RFS2. EPA believes that cellulosic renewable fuels are least likely to achieve the RFS2 mandates due to market forces alone. While current DOE and USDA programs are helping to stimulate the market for cellulosic renewable fuels, investment in this segment of the fuels market is still very limited. The limitations of market forces are reflected in the projections of AEO2009, which despite projecting large increases in oil prices still projects that renewable fuel volumes will be less than those required by RFS2.

Given the difficulty in projecting renewable fuel volumes in the absence of the RFS2 standards, EPA chose to rely on the projections in AEO2007 as its primary reference case. EPA believes that the actual renewable fuel volumes achieved in the absence of the RFS2 standards would fall somewhere between its reference case projections and the volumes mandated by RFS2. The impacts estimated in this RIA therefore cannot be interpreted as the impact of the RFS2 program itself. Rather, they are an estimate of the impact of an increase in use of renewable fuels, whether caused by RFS2 or by market forces.

Another important limitation of this analysis is that it does not consider certain offsetting effects. In particular, for our emissions (GHG and non-GHG) and air quality analyses we have assumed that the production of renewable fuels to satisfy the RFS2 results in an energy equivalent decrease in production of petroleum-derived fuels. This is despite the fact that our other analyses predict that increased renewable fuel use will reduce worldwide crude oil prices, which in turn could lead to an increase in the quantity of crude oil demanded. Thus, there may be offsetting effects that are not completely captured by our analysis. For example, an increase in world demand for crude oil resulting from depressed prices caused by the increased use of renewable fuels in the U.S could partially offset some of the decrease in GHG emissions we have projected. At the same time, there may be other indirect impacts as well that might go in the opposite direction, since crude oil is used for more than just the gasoline and diesel fuel being displaced by renewable fuels.

The table below provides the results of many of the analyses contained throughout this RIA. Only shown are the results for the RFS2 volume control case relative to the AEO2007 reference case, and only the results for 2022 when the program is fully phased in.

## Impact Summary of the Renewable Fuel Volumes Required by RFS2 in 2022 Relative to the AEO2007 Reference Case (2007 Dollars)

| **Category** | **Impact in 2022** | **Chapter Discussed** |
|---|---|---|
| **Emissions and Air Quality** | | |
| GHG Emissions | -138 million metric tons | 2.7 |
| Non-GHG Emissions (criteria and toxic pollutants) | -1 to +10% depending on the pollutant | 3.2 |
| Nationwide Ozone | +0.12 ppb population-weighted seasonal max 8hr average | 5.4 |
| Nationwide $PM_{2.5}$ | +0.002 $\mu g/m^3$ population-weighted annual average $PM_{2.5}$ | 5.4 |
| Nationwide Ethanol | +0.409 $\mu g/m^3$ population-weighted annual average | 3.4 |
| Other Nationwide Air Toxics | -0.0001 to -0.023 $\mu g/m^3$ population-weighted annual average depending on the pollutant | 3.4 |
| $PM_{2.5}$-related Premature Mortality | 33 to 85 additional cases of adult mortality (estimates vary by study) | 5.4 |
| Ozone-related Premature Mortality | 36 to 160 additional cases of adult mortality (estimates vary by study) | 5.4 |
| | | |
| **Other Environmental Impacts** | | |
| Loadings to the Mississippi River from the Upper Mississippi River Basin | Nitrogen: +1.43 billion lbs. (1.2%)<br>Phosphorus: +132 million lbs. (0.7%) | 6.4 |
| | | |
| **Fuel Costs** | | |
| Gasoline Costs | -2.4¢/gal | 4.4 |
| Diesel Costs | -12.1 ¢/gal | 4.4 |
| Overall Fuel Cost | -$11.8 Billion | 4.4 |
| Gasoline and Diesel Consumption | - 13.6 Bgal | 4.4 |
| | | |
| **Capital Costs** | | |
| Total Capital Costs Thru 2022 | $90.5 Billion | 4.4 |
| | | |
| **Food Costs** | | |
| Corn | +8.2% | 5.1 |
| Soybeans | +10.3% | 5.1 |
| Food | +$10 per capita | 5.1 |
| | | |
| **Economic Impacts** | | |

| | | |
|---|---|---|
| Energy Security | +$2.6 Billion | 5.2 |
| Monetized Health Impacts | -$0.63 to -$2.2 Billion | 5.4 |
| Monetized GHG Impacts (SCC)[a] | +$0.6 to $12.2 Billion (estimates vary by SCC assumption) | 5.3 |
| Oil Imports | -$41.5 Billion | 5.2 |
| Farm Gate Food | +$3.6 Billion | 5.1 |
| Farm Income | +$13 Billion (+36%) | 5.1 |
| Corn Exports | -$57 Million (-8%) | 5.1 |
| Soybean Exports | -$453 Million (-14%) | 5.1 |
| | | |
| **Total Benefits in 2022[b]** | +$13 to $26 Billion (estimates vary by SCC assumption) | 5.5 |
| | | |

[a] The models used to estimate SCC values have not been exercised in a systematic manner that would allow researchers to assess the probability of different values. Therefore, the interim SCC values should not be considered to form a range or distribution of possible or likely values. See Section 5.3 for a complete summary of the interim SCC values.

[b] Sum of Overall Fuel Costs, Energy Security, Monetized Health Impacts, and GHG Impacts (SCC) in 2022. This measure does not include the costs of the investments needed to increase renewable fuel production. Those capital costs through 2022 total to $90.5 billion.

The document is organized as follows:

Chapter 1: Renewable Fuel Production and Consumption

This chapter describes the various feedstocks and renewable fuel types that could potentially be used to meet the renewable fuel volumes required by EISA. The availability and challenges of harvesting, storing, and transporting these feedstocks are discussed, as well as the different renewable fuel production technologies, industry plans, and potential growth projections for future facilities. A discussion of renewable fuel distribution and consumption is included. Chapter 1.2 defines the reference and RFS2 control cases that were used throughout the rest of this Regulatory Impact Analysis to assess the impacts of the increased renewable fuel volumes needed to reach the RFS2 mandated volumes.

Chapter 2: Lifecycle GHG Analysis

This chapter describes the methodology used to determine the lifecycle greenhouse gas (GHG) emissions of the renewable fuels required by EISA, and to determine which fuels qualify for the four GHG reduction thresholds established in EISA. Future inclusion of other feedstocks and fuel is discussed, as well as the overall GHG benefits of the RFS program. It also contains our assessment of the GHG emission reductions projected to result from the increased use of renewable fuels.

Chapter 3: Impacts on Non-GHG Pollutants

This chapter discusses the expected impacts of increased renewable fuel volumes on emissions of hydrocarbons (HC), oxides of nitrogen (NOx), carbon monoxide (CO), particulate matter (PM10 and PM2.5), sulfur oxides (SOx), ammonia (NH3), ethanol, and air toxic emissions of benzene, 1,3-butadiene, acetaldehyde, formaldehyde, acrolein, and naphthalene. Emissions from vehicles and off-road equipment, as well as emissions from the entire fuel production and distribution chain are considered. .  This chapter also presents the projected impacts of increased renewable fuel volumes on ambient concentrations of $PM_{2.5}$, ozone and air toxic pollutants, and describes the health and environmental effects associated with these pollutants.

Chapter 4:  Impacts on Cost of Renewable Fuels, Gasoline, and Diesel

The impact of increasing the use of renewable fuels on the production and distribution costs of transportation fuels are discussed.  Renewable fuel production and distribution costs are presented along with their impact on gasoline and diesel fuel costs.  Per-gallon and nationwide costs are presented.

Chapter 5:  Economic Impacts

This chapter summarizes the impacts of increased renewable fuel use on the U.S. and international agricultural sector, U.S. petroleum imports, and the consequences of reduced oil imports on U.S. energy security.  It also examines the greenhouse gas benefits and the co-pollutant health and environmental impacts from the wider use of renewable fuels in the U.S. needed to meet the RFS2 mandated volumes.

Chapter 6:  Impacts on Water

This chapter discusses the impacts of increased renewable fuel volumes on water quality and quantity.  Changes in the Upper Mississippi River Basin watershed were modeled.

Chapter 7:  Final Regulatory Flexibility Analysis

The Final Regulatory Flexibility Analysis (FRFA) evaluates the impacts of the RFS2 standards on potential small entities.  In developing the FRFA, we conducted outreach and held meetings with representatives from the various small entities that could be affected by the rulemaking.  Small business recommendations and final rule provisions are discussed.

Appendix

EPA conducted a comprehensive analysis of the NOx, PM, HC, and CO emission impacts of biodiesel blends based on heavy-duty, in-use diesel chassis and engine exhaust emissions data.

# List of Acronyms and Abbreviations

| | |
|---|---|
| ACE | American Coalition for Ethanol |
| ACS | American Cancer Society |
| ADM | Archer Daniels Midland |
| AEO | Annual Energy Outlook (an EIA publication) |
| AHC | Aromatic hydrocarbons |
| ARMS | Agricultural Resource Management Survey |
| ASTM | American Society of Testing and Materials |
| B0, B5, B20, etc | Percent of biodiesel, e.g., B5= 5% biodiesel, 95% diesel |
| bbl | Barrel |
| BEA | Bureau of Economic Analysis |
| Bgal, bgal, bilgal, bg | Billions of gallons |
| BGY | Billions of gallons per year |
| BPCD | Barrels Per calendar day |
| BPSD | Barrels per stream day |
| bpd, bbls/day | Barrels Per Day |
| Brix | A measurement of the sugar content of a solution at a given temperature |
| BTL | Biomass-to-liquid |
| BTU | British Thermal Unit |
| BU | Bushel |
| Bu/acre | Bushels per acre |
| BZ | Benzene |
| C | Carbon |
| C&D | Construction and Demolition |
| CA | California |
| CAA | Clean Air Act |
| CAIR | Clean Air Interstate Rule |
| CARB | California Air Resources Board |
| CaRFG3 | California Phase 3 RFG |
| CBG | Cleaner Burning Gasoline |
| CBI | Caribbean Basin Initiative |
| CB05 | Carbon Bond 05 |
| CD | Census Division |
| CFEIS | EPA's Certification and Fuel Economy Information System |
| CFR | Code of Federal Regulations |
| c/gal | Cents per gallon |
| CG | Conventional Gasoline |
| $CH_3CHO$ | Acetaldehyde |
| $CH_3C(O)OO\cdot$ | Acetyl peroxy radical |
| $CH_3C(O)OONO_2$ | Peroxyacetyl nitrate |
| CHF | Congestive heart failure |
| CHP | Combined Heat and Power Technology |
| CIMT | Carotid intima-media thickness |
| CMAQ | Community Multi-scale Air Quality model |
| CO | Carbon Monoxide |
| CO2 | Carbon Dioxide |
| COHb | Carboxyhemoglobin |
| Co-op | Cooperative |
| CRC | Coordinating Research Council |
| CRGNSA | Columbia River Gorge National Scenic Area |

| | |
|---|---|
| CRP | Conservation Reserve Program |
| CTL | Coal-to-liquid |
| DDGS | Distillers’ Dried Grains with Solubles |
| DGS | Distillers’ Grains with Solubles |
| DHHS | Department of Health and Human Services |
| DOE | Department of Energy |
| DRIA | Draft Regulatory Impact Analysis |
| dt | Dry ton |
| E&C | Engineering and Construction |
| E0 | Gasoline Blend which Does Not Contain Ethanol |
| E10 | Gasoline Blend containing a nominal 10 percent ethanol by volume |
| E85 | Gasoline Blend containing 85 percent ethanol by volume |
| E200 | Percent of Fuel Evaporated at 200 Degrees F (ASTM D 86) |
| E300 | Percent of Fuel Evaporated at 300 Degrees F (ASTM D 86) |
| EIA | Energy Information Administration (part of the U.S. Department of Energy) |
| EISA | Energy Independence and Security Act |
| Energy Act | Energy Policy Act of 2005 (also the Act) |
| EPA | Environmental Protection Agency |
| EPAct | Energy Policy Act of 2005 (also ‘the Energy Act’ or ‘the Act’) |
| ETBE | Ethyl Tertiary Butyl Ether |
| ETOH | Ethanol |
| EU | European Union |
| ex CA | Excluding California |
| F, °F | Fahrenheit |
| F-T | Fischer-Tropsch |
| FAME | Fatty acid methyl ester |
| FAPRI | Farm and Agricultural Policy Research Institute |
| FASOM | Forestry and Agriculture Sector Optimization Model |
| FBP | Feed Boiling Point (also Final Boiling Point) |
| FCC | Fluidized Catalytic Cracker |
| FCCU | Fluidized Catalytic Cracking Unit |
| FHWA | Federal Highway Administration |
| FOEB | Fuel Oil Equivalent Barrel |
| FR | Federal Register |
| FRM | Final Rulemaking |
| FRTP | Fixed Reduction Trigger Point |
| FFV | Flexible Fuel Vehicle |
| FTP | Federal test procedure |
| g/Btu | Grams per Btu |
| g/day | Grams per day |
| Gal, gal | Gallon |
| GDP | Gross Domestic Product |
| GEOS | Goddard Earth Observing System |
| GHG | Greenhouse Gases |
| GPA | Geographic Phase-in Area |
| GREET | Greenhouse Gas, Regulated Emissions, and Energy Use in Transportation model |
| GWP | Global warming potentials |
| ha | Hectare |
| $H_2O$ | Water |
| HC | Hydrocarbon(s) |
| HCO | Heavy Cycle Oil (a refinery stream) |
| HCHO | Formaldehyde |
| HDN | Naphtha Hydrotreater (also Hydro-Denitrogenation Unit) |

| | |
|---|---|
| HEI | Health Effects Institute |
| $HNO_3$ | Nitric acid |
| HSR | Heavy Straight Run (a refinery stream) |
| HVGO | Heavy Vacuum Gas Oil (a refinery stream) |
| IARC | International Agency for Research on Carcinogens |
| IBP | Initial Boiling Point |
| IRFA | Initial Regulatory Flexibility Analysis |
| k | Thousand |
| kbbl | Thousand barrels |
| kg | kilogram |
| kwh | Kilowatt Hour |
| L, l | Liter |
| Lb, lb | Pound |
| LCC | Land Capability Classification |
| LCO | Light Cycle Oil (a refinery stream) |
| LEV | Low emission vehicle |
| LLE | Liquid-Liquid Extraction |
| LNS | Light Naphtha Splitter |
| LP | Linear Programming (a type of refinery model) |
| LSR | Light Straight Run (a refinery stream) |
| $m^2$ | Square meter |
| MCIP | Meteorology-Chemistry Interface Processor |
| $mg/m^3$ | Milligrams per cubic meter |
| MGY, MMgy | Million Gallons per Year |
| mm | Millimeter |
| MM | Million |
| MMBTU | Million British Thermal Units |
| MMbbls/cd | Millions of barrels per calendar day |
| MMGal/yr | Millions of gallons per year |
| MOBILE (5, 6, 6.2) | EPA’s Motor Vehicle Emission Inventory Model (versions) |
| MON | Motor Octane Number |
| MOVES | Motor Vehicle Emissions Simulator |
| MOVES2006 | EPA’s Next Generation Highway Vehicle Emission Model |
| MSAT | Mobile Source Air Toxics |
| MSAT1 | 2001 Mobile Source Air Toxics Rule |
| MSAT2 | 2006 Proposed Mobile Source Air Toxics Rule |
| MSW | Municipal Solid Waste |
| Mt | Metric ton |
| MTBE | Methyl Tertiary-Butyl Ether |
| N | Nitrogen |
| NAAQS | National Ambient Air Quality Standards |
| NAICS | North American Industrial Classification System |
| NASS | National Agricultural Statistics Service |
| NATA | National Air Toxic Assessment |
| NBB | National Biodiesel Board |
| NCGA | National Corn Growers Association |
| NCI | National Cancer Institute |
| NCLAN | National Crop Loss Assessment Network |
| NCSU | North Carolina State University |
| NGL | Natural gas plant liquids |
| NH3 | Ammonia |
| NIOSH | National Institute of Occupational Safety and Health |
| NMHC | Non-Methane Hydrocarbons |

| | |
|---|---|
| NMIM | National Mobile Inventory Model (EPA software tool) |
| NMOG | Non-methane organic gases |
| NONROAD | EPA's Non-road Engine Emission Model |
| NONROAD2005 | EPA's Non-road Engine Emission Model Released in 2005 |
| NO | Nitric oxide |
| $NO_2$ | Nitrogen dioxide |
| $NO_x$ | Oxides of nitrogen |
| NPRM | Notice of Proposed Rulemaking |
| NRC | National Research Council |
| NRCS | Natural Resource Conservation Service |
| NREL | National Renewable Energy Laboratory |
| $O_3$ | Ozone |
| OA | Organic aerosol |
| OC | Organic carbon |
| ·OH | Hydroxyl radical |
| OM | Organic mass |
| OMB | Office of Management and Budget |
| OMHCE | Organic Material Hydrocarbon Equivalent |
| ORD | Office of Research and Development |
| ORNL | Oak Ridge National Laboratory |
| OTAQ | Office of Transportation and Air Quality |
| Oxy-fuel, oxyfuel | Winter oxygenated fuel program |
| PADD | Petroleum Administration for Defense District |
| PAHs | Polycyclic aromatic hydrocarbons |
| PAN | Peroxyacetyl nitrate |
| PM | Particulate Matter |
| $PM_{10}$ | Coarse Particle |
| $PM_{2.5}$ | Fine Particle |
| PM AQCD | Particulate Matter Air Quality Criteria Document |
| PMA | Petroleum Marketing Annual (an EIA publication) |
| POM | Polycyclic Organic Matter |
| PONA | Paraffin, Olefin, Naphthene, Aromatic |
| ppb | Parts per billion |
| ppm | Parts Per million |
| PPN | Peroxypropionyl nitrate |
| PRTP | Percentage Reduction Trigger Point |
| PSI | Pounds per Square Inch |
| QBtu | Quadrillion btu |
| Quadrillion | $10^{15}$ |
| (R+M)/2 | Octane calculation (RON+MON)/2 |
| R&D | Research and Development |
| RBOB | Reformulated Blendstock for Oxygenate Blending |
| rd | Renewable diesel |
| RFA | Regulatory Flexibility Act |
| RFG | Reformulated Gasoline |
| RFS | Renewable Fuels Standard |
| RFS1 | Renewable Fuels Standard Program promulgated in 2007. |
| RFS2 | Renewable Fuels Standard Changes |
| RIA | Regulatory Impact Analysis |
| RIMS | Regional Input-Output Modeling System |
| RIN | Renewable Identification Number |
| RON | Research octane number |
| RPMG | Renewable Products Marketing Group |

| | |
|---|---|
| RSM | Response Surface Model |
| RVP | Reid Vapor Pressure |
| S | Sulfur |
| SBA | Small Business Administration |
| SBAR Panel, or ‘the Panel’ | Small Business Advocacy Review Panel |
| SBREFA | Small Business Regulatory Enforcement Fairness Act (of 1996) |
| scf | Standard cubic feet |
| SER | Small Entity Representative |
| SI | Spark Ignition |
| SOA | Secondary Organic Aerosol |
| SOC | Secondary organic carbon |
| SOC | Soil organic carbon |
| SOx | Oxides of Sulfur |
| SULEV | Super ultra low emission vehicle |
| SVOC | Semi-volatile organic compound |
| T50 | Temperature at which 50% (by volume) of fuel evaporates (ASTM D 86) |
| T90 | Temperature at which 90% (by volume) of fuel evaporates (ASTM D 86) |
| TAME | Tertiary Amyl Methyl Ether |
| Ton | 2000 lbs |
| Tonne | Metric tonne (equivalent to 1.1 tons); also metric ton |
| TRQ | Tariff rate quotas |
| ULEV | Ultra low emission vehicle |
| U.S.C. | United States Code |
| USDA | U.S. Department of Agriculture |
| VGO | Vacuum Gas Oil (a refinery stream) |
| VMT | Vehicle Miles Traveled |
| VOC | Volatile Organic Compound |
| vol% | Percent by volume, volume percent |
| WDGS | Wet Distillers Grain w/ Solubles |
| wt% | Percent by weight, weight percent |
| yr, y | Year |

# Chapter 1: Renewable Fuel Production and Consumption

## 1.1 Biofuel Feedstock Availability

Currently, the main feedstocks used for renewable fuel production in the U.S. are corn for ethanol and soy for biodiesel. As technologies improve, we expect more emphasis on using cellulosic feedstocks such as agricultural residues, forestry residues, etc. However, limitations may occur due to concerns over sustainable removal rates for initial cellulosic feedstocks. Thus, dedicated energy crops which are touted as requiring low fertilizer and energy inputs as well as having the ability of being grown on marginal lands may also enter the market. The following sections discuss the current and potential availability of biofuel feedstocks and the potential challenges that must be overcome in order for enough feedstock to be collected and converted to biofuel to meet the EISA requirement of 36 billion gallons of renewable fuel by 2022.

### 1.1.1 Starch/Sugar Feedstocks

The following sections describe starch and sugar feedstocks that can be used to produce ethanol. Currently, the majority of ethanol that is produced in the U.S. is from corn. Recently, there have been plans to convert sugarcane grown in the U.S. into ethanol as well as the introduction of relatively new crop varieties for biofuel conversion. We also describe feedstocks used in the production of ethanol outside the U.S.

#### 1.1.1.1 Domestic Corn and Other Grain Ethanol

Today's ethanol is primarily corn-based ethanol, which accounts for the majority of the over 10 billion gallons of domestic fuel ethanol estimated to be produced by the end of 2009. According to multiple sources, as much as 18 billion gallons of corn ethanol could be produced by the 2016-18 timeframe, see Table 1.1-1.[1] For the final rule, we modeled 15 billion gallons of corn ethanol to meet the EISA standards. We used the Forestry and Agriculture Sector Optimization Model (FASOM) and the Farm and Agricultural Policy Research Institute (FAPRI-CARD) model to assess the impact of increased renewable fuel volume from business-as-usual on crop acreage, crop allocation to fuel vs. other uses, costs, etc. See Section 1.2 for more discussion on the renewable fuel volumes assumed for our analyses and Chapter 5 of the RIA for more details on the agricultural modeling. Important modeling parameters considered include crop yields and ethanol yield per bushel of feedstock as these factors impact the amount of feedstock necessary per gallon of biofuel produced. Table 1.1-1 also shows a summary of the parameters used and the results from our analyses.

**Table 1.1-1. Corn Ethanol Production Forecast Parameters and Corresponding Years**

| Source (cited in text above) | Fuel Volumes/Year (billion gallons) | Acres Planted (millions) | Yield (bu/acre) | Corn Allocation to Ethanol | Ethanol Conversion (gal/bu)[b] |
|---|---|---|---|---|---|
| USDA Baseline | 14/2018 | 90 | 175 | 35% | 2.76 |
| USDA Study | 15/2016 | 92 | 170 | 37% | 2.8 |
| NCGA Analysis[c] | 12.8-17.8/2016 | 76-78[a] | 178-193 | 33-40% | 2.9-3.0 |
| EPA FRM Analysis (Base Yield Case) | 15/2022 | 92/81[a] | 185 | 41% | 2.85 |
| EPA FRM Analysis (Higher Yield Case) | 15/2022 | 77/71[a] | 233 | 36% | 2.85 |

[a] Acres harvested

[b] We assume all figures above include denaturant, but most references do not specify; Differences also occur depending on whether dry or wet mills are assumed, wet mills have slightly lower yields

[c] National Corn Growers Association

Corn is mainly grown in 12 states within the United States: Illinois, Indiana, Iowa, Kansas, Kentucky, Michigan, Minnesota, Missouri, Nebraska, Ohio, South Dakota, and Wisconsin.[2] See Table 1.1-2.

**Table 1.1-2.**
**U.S. Corn for Grain Area Harvested by State in 2008 and Forecasted November 1, 2009**

| State | Total Harvested 2008 (1000 Acres) | 2009 Forecast (1000 Acres) |
|---|---|---|
| Illinois | 11,900 | 11,800 |
| Indiana | 5,460 | 5,440 |
| Iowa | 12,800 | 13,350 |
| Kansas | 3,630 | 3,870 |
| Kentucky | 1,120 | 1,130 |
| Michigan | 2,140 | 1,990 |
| Minnesota | 7,200 | 7,100 |
| Missouri | 2,650 | 2,900 |
| Nebraska | 8,550 | 8,900 |
| Ohio | 3,120 | 3,120 |
| South Dakota | 4,400 | 4,600 |
| Wisconsin | 2,880 | 2,900 |
| Other States | 12,790 | 12,194 |
| **Total** | **78,640** | **79,294** |

Corn yield per acre has been increasing over the past three decades.[A,3] See Figure 1.1-1**.** In our economic modeling assessment under the base yield case, the national average corn yield is approximately 185 bu/acre in 2022, with specific yields calculated at the regional level. The national average depends on crop production in each region in a given year (see Chapter 5 of this RIA). These yield increases over time are consistent with the United States Department of Agriculture (USDA) projections.[4] As further described in Chapter 5, we also investigated a

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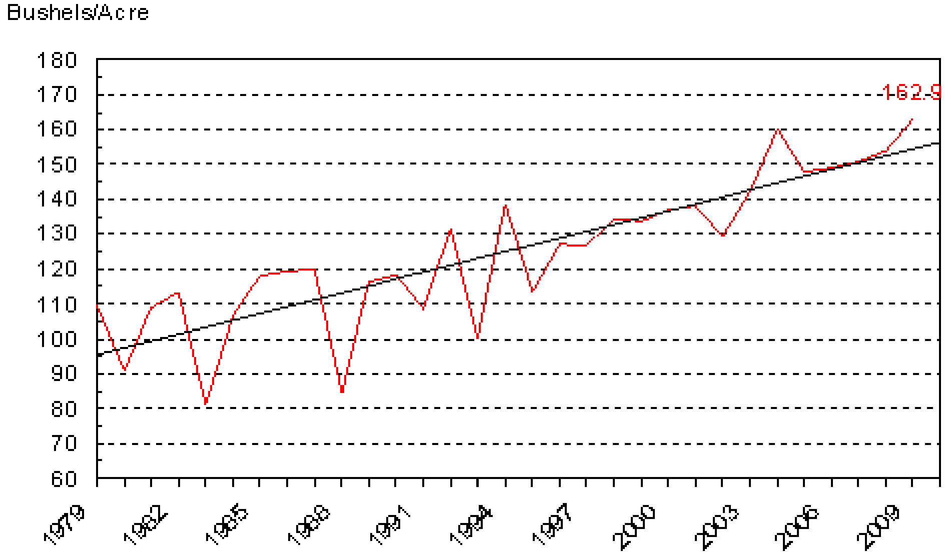
[A] Calculated from 1977-2007.

higher corn yield scenario of 233 bu/acre in 2022, developed in consultation with our colleagues at USDA as well as industry groups e.g. Monsanto and Pioneer.

**Figure 1.1-1. U.S. Corn Yields (1978-2009)**



USDA-NASS
11-10-09

The percent of U.S. corn produced allocated to ethanol has increased in recent years. In 2007, the percent of U.S. corn used for ethanol was around 23 percent and in 2008 the percent had increased to 30 percent. As of December 2009, the majority of corn is still being used as animal feed (42 percent), with smaller portions going to ethanol (33 percent), exports (16 percent), and human food and seed (9 percent).[5] For the final rule, the FASOM projects that approximately 41 percent of corn would need to be allocated to the ethanol industry by 2022 under the base corn yield assumption and 36 percent of corn under the higher corn yield assumptions to produce 15 billion gallons of corn ethanol.

The amount of corn allocated to fuel vs. other uses has caused much controversy over the production and use of corn-based ethanol in the past few years. There is concern that the use of corn for fuel could potentially divert corn needed to feed people. On the other hand, it is entirely possible that other countries (e.g. Argentina or Brazil) could increase their production of corn to match the increase in demand for food *and* fuel, thus meeting both needs. In addition, higher crop yields in all countries could decrease the amount of land necessary for a fixed amount of renewable fuel produced. We rely on our modeling results to help inform us of the potential impacts of an increased growth in renewable fuels (see Chapter 5 for more detail).

Over the last 15 years, ethanol industry optimization of cooking, mashing, and fermentation conditions has increased the amount of ethanol produced from a bushel of corn. According to USDA reports, by about 2010 we can expect all plants on-line to yield an average of 2.76 gallons per bushel.[6,7] In addition, based on discussions with USDA, we believe it is reasonable to expect an increase in corn kernel starch content of 2-4 percent over the next decade through advances in plant breeding and new corn varieties. Combining these figures, we project industry average denatured ethanol yields to reach 2.85 gallons per bushel by 2022 for dry mills and 2.63 gallons per bushel for wet mills. See Section 1.4 of this RIA for more information on corn ethanol biofuel production technologies, e.g. dry mill vs. wet mill.

Other grains that can be processed into ethanol include grain sorghum (milo), wheat, and barley. The production of ethanol from these grains generally involves the same processes as the production from corn, and can be used together in the same plant.

#### 1.1.1.2 Imported Sugar Ethanol

After corn, sugar crops (i.e. sugar beets and sugarcane) are the world's next largest feedstock sources for ethanol.[8,9] Sugar beets are mainly grown in France, Germany, and in the U.S., with the majority of the feedstock typically used to produce sugar for food and feed. Compared to sugar beets, sugarcane is produced in much higher volume and has been able to support a growing sugar and ethanol market. Due to a higher availability of sugarcane feedstock for ethanol production, we expect that imported ethanol to the U.S. will likely come from sugarcane.

World production of sugarcane is approximately 1.4 billion metric tons (MT) and is concentrated mainly in tropical regions, particularly in Latin America, Africa, and South and Southeast Asia. Roughly 100 countries produce sugarcane today.[10] Brazil is currently the world's largest producer of sugarcane (569 million MT in the 2008/9 harvest season) and offers the greatest potential for growth, due primarily to the availability of suitable lands for expanding sugarcane cultivation.[11] In Brazil, just 20% of the arable land is cultivated, totaling 156 million acres. The following Table 1.1-3., describes the land available/used in 2007. As there are 494 million acres of pastureland and a considerable area of unused arable land (190 million acres), it is believed that there could be a large expansion in sugarcane.[12]

**Table 1.1-3. Brazil Land Areas in 2007.[13]**

| Million Acres | |
|---|---|
| Brazil (Total Area) | 2100 |
| Total Preserved Areas and Other Uses* | 1260 |
| Total Arable Area | 840 |
| Cultivated Land (All Crops) | 156 |
| Soybeans | 51 |
| Corn | 35 |
| Oranges | 2 |
| Sugar Cane | 19 |
| Sugar Area | 11 |
| Ethanol Area | 8 |
| Pastureland | 494 |
| Available land (ag, livestock) | 190 |

***Areas include Amazon Rain Forest, protected areas, conservation and reforestation areas, cities and towns, roads, lakes, and rivers.**

The statistics above, however, do not indicate whether the land available requires any additional usage of water or has the proper soil and climate conditions for sugarcane. According to one study, there is at least 148 million acres of additional land available with proper soil and climate conditions for sugarcane without utilizing environmentally protected land (i.e. Amazon and native reserves) and without the use of irrigation.[14] This translates to approximately 90 billion gallons of ethanol potential (using a yield of approximately 600 gal/acre which is a conservative estimate based on existing technology). Although it is not probable that all this land will be converted to sugarcane ethanol, the estimate puts into prospective the large potential for sugarcane ethanol to be produced in Brazil.

Another study commissioned by the Brazilian Government produced an analysis in which Brazil's arable land was evaluated for its suitability for cane. The benefit of this study is that it provides more detail on the land quality and yield assumptions used in its estimates than the study and statistics shown above.[15] The study eliminated areas protected by environmental regulations and those with a slope greater than 12% (those not suitable for mechanized farming). The following Table 1.1-4 shows an estimate of the available land that could be used for sugarcane expansion. The potential fuel volume from these acres is dependent on whether or not irrigation takes place. Overall, with greater irrigation, more acres are available that fall in the higher potential yield categories than without irrigation. As can be seen, there are potentially large areas of land available for sugarcane expansion in Brazil.

**Table 1.1-4.**
**Potential Volumes Utilizing Available Land for Sugarcane Expansion**[B,16,17]

| Potential | Ethanol Yield (gal/acre) | Potential Area (million acres) | | Potential Ethanol Volume (billion gallons) | |
|---|---|---|---|---|---|
| | | w/o irrigation | w/ irrigation | w/o irrigation | w/ irrigation |
| High | 659 | 20 | 94 | 13 | 62 |
| Good | 592 | 281 | 242 | 166 | 143 |
| Average | 524 | 369 | 414 | 193 | 217 |
| Inadequate | 0 | 224 | 143 | 0 | 0 |
| Total | | 894 | 894 | 373 | 422 |

The actual potential for ethanol from sugarcane will, however, be further limited by the amount of sugarcane diverted towards food and other uses. Taking into account demands for food and feed, the Oak Ridge National Laboratory (ORNL) *Biofuel Feedstock Assessment for Selected Countries* report suggests that perhaps more than 30 billion gallons of ethanol-equivalent fuel could be produced from available sugarcane supply by 2017. Brazil is estimated to produce approximately 2/3 of the potential supply. The majority of this supply would likely be consumed within the country, with the leftover potentially available for export to the U.S. and other countries. Recent government and industry estimates indicate that approximately 3.8-4.2 bgal of ethanol could be available for export from Brazil by 2022 (with close to 17 billion gallons being produced and 13 billion gallons consumed domestically). See Section 1.5.2.1 of

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[B] Adapted from CGEE, ABDI, Unicamp, and NIPE, Scaling Up the Ethanol Program in Brazil. Assumed a conversion factor of 20 gallons of ethanol per tonne of sugarcane feedstock to compute gal/acre. A "high" potential refers to ethanol yields that are higher than current industry averages, while "good" refers to good quality land and productivity that is about equal to the current average. Explanations for "Average" and "Inadequate" were not provided.

this RIA for further details on Brazilian ethanol production and consumption. Thus, there appears to be a large enough potential for Brazil to increase production of sugarcane to meet its internal demands as well as export to the United States and other countries.

Countries other than Brazil generally lack the land resources, appropriate soils, and climate for large expansion of sugarcane production.[18] India and China are the second and third largest producers, however, most of the cultivatable land area is already in use and government policies discourage reallocation of arable land for biofuel production. Although Argentina and Columbia have significant underutilized lands available, these resources generally do not have suitable soil and climate characteristics for sugarcane production. Due to these factors, Brazil is the most likely country able to produce substantial volumes of sugarcane for biofuel production in the future.

### 1.1.1.3 Domestic Sugar Ethanol

Currently, there are no U.S. plants producing ethanol from sugar feedstocks.[19] Brazil and several other countries are producing ethanol from sugarcane, sugarbeets, and molasses, showing that it is economically feasible to convert these feedstocks into ethanol (see Section 1.1.1.2). However, the economics of producing ethanol from sugar feedstocks in these countries is not directly comparable to the economics of producing ethanol from sugar feedstocks in the U.S. Over the longer term, the profitability of producing ethanol from sugarcane, sugarbeets, and molasses depends on the prices of these crops, the costs of conversion, and the price of gasoline.

Sugarcane in the U.S. is grown mainly in Florida and Louisiana, with smaller amounts from Hawaii and Texas. See Table 1.1-5. Sugarbeets, on the other hand, are grown in more northern states, with the majority of production in Minnesota, Michigan, and Idaho as shown in Table 1.1-6. As noted, these feedstocks are not currently used for commercial production of ethanol, however, this may change in the near future.

**Table 1.1-5.**
**Sugarcane Area Harvested (for sugar only, not seed) by State in 2008 and 2009**

| State | Total Harvested 2008 (1000 Acres) | Total Harvested 2009 (1000 Acres) |
|---|---|---|
| Florida | 384 | 372 |
| Hawaii | 20 | 20 |
| Louisiana | 380 | 375 |
| Texas | 37 | 39 |
| **Total** | **821** | **806** |

**Table 1.1-6.**
**Sugarbeet Area Harvested by State in 2008 and 2009**

| State | Total Harvested 2008 (1000 Acres) | Total Harvested 2009 (1000 Acres) |
|---|---|---|
| Idaho | 116 | 163 |
| Michigan | 136 | 136 |
| Minnesota | 399 | 455 |
| Other States | 354 | 397 |
| **Total** | **1005** | **1151** |

Recent news indicates that there are plans in the U.S. to produce ethanol from sugar feedstocks. For instance, sugarcane has been grown in California's Imperial Valley specifically for the purpose of making ethanol and using the cane's biomass to generate electricity to power the ethanol distillery as well as export excess electricity to the electric grid.[20] There are at least two projects being developed at this time that could result in several hundred million gallons of ethanol produced. One company is California Ethanol and Power which is currently in the development stage and plans to build a facility that produces 60 million gallon per year of sugarcane ethanol and 50 megawatts of electricity.[21] The company plans to break ground by early 2010 and be operational by 2011. The sugarcane is being grown on marginal and existing cropland that is unsuitable for food crops and will replace forage crops like alfalfa, Bermuda grass, Klein grass, etc. Harvesting is expected to be fully mechanized. Another company is Pacific West Energy LLC which plans to produce 12-15 million gallons per year of ethanol on the island of Kauai in Hawaii, perhaps as early as 2010. Hawaii is well suited for sugarcane ethanol production due to several factors, including lower costs for feedstock compared to those in the continental U.S., high prices for electricity and liquid fuels, and state production incentives.[22] Thus, there is potential for these projects and perhaps others to help contribute to the EISA biofuels mandate.

There is also potential for the use of new crops with certain traits similar to traditional sugar and corn feedstocks. For example, a new crop referred to as Sugarcorn is a hybrid cross between sugarcane and corn.[23] The plant contains genes from Midwestern corn, tropical maize and sugarcane, resulting in a variety that doesn't flower to produce grain but instead produces sugar in its stalks. Researchers are currently working to increase sugar yields, increase the plant's hardiness and develop ways to prevent the plant from being pollinated by nearby crops of traditional corn. Potential benefits include reduced water and fertilizer consumption during the growth of the plant.

Another crop receiving greater attention is sweet sorghum. Sweet sorghum refers to varieties of sorghum with high concentration of soluble sugars in the sap.[24] They are used for the production of syrup, alcoholic beverages, crystal sugar, etc. The interest in bioenergy production from sweet sorghum comes from the easy accessibility of readily fermentable sugars combined with very high yields for biomass. Yield varies with location and variety and ranges from 8-49 tons/acre. After extraction of the juice, the bagasse can also be used as cellulosic feedstock or other purposes. Groups interested in building facilities in the U.S. that can process sorghum juice include the Tampa Bay Area Ethanol Consortium in Florida and the Texas BioEnergy Marketing Associates in Texas.

### 1.1.2 Cellulosic Biofuel Feedstocks

Various cellulosic feedstocks can potentially be used to produce cellulosic biofuel. These include agricultural residues, forest residues, urban waste, and dedicated energy crops. We describe each type in the following sections.

#### 1.1.2.1 Agricultural Residues

The harvesting of agricultural residues could provide a large source of readily available feedstock for cellulosic biofuels. We estimated the amount of crop residue could potentially be produced, and of that, how much could be removed or harvested to determine the total amount that could be available to produce biofuel in 2022. The amount of residue that can be harvested is limited by how much residue must be left on the field to maintain soil health and by the mechanical efficiency of the harvesting operation. We discuss harvesting limitations due to maintaining soil health below, while mechanical efficiencies, storage, and transport issues are discussed in Section 1.3 of this RIA. Feedstock costs are discussed in Section 4.1.1.2 of the RIA.

*Sustainable Removal*

In terms of soil health, residues perform many positive functions for agricultural soils. Recent studies and reviews have attempted to address these issues. Existing research can be used to some extent to guide practices or make estimates, especially for corn stover harvest in the Corn Belt, which has been studied more extensively than other residues except, perhaps, wheat.

In a review by five USDA Agricultural Research Service (ARS) scientists, Wilhelm et al. acknowledged the complexity of interactions between soil type, climate, and management when considering crop residue effects on soil. They recommended that removal rates be based on regional yield, climatic conditions and cultural practices, with no specific rates given.[25] Using the Revised Universal Soil Loss Equation (RUSLE) technology and the Wind Erosion Equation (WEQ), Nelson predicted safe residue removal rates for minimizing soil loss in the Eastern and Midwestern U.S. These predictions varied widely over time and location as a result of the complex interactions discussed by Wilhelm et al.[26,27] In another recent review, sponsored by the U.S. Department of Energy (DOE), Mann et al. concluded that before specific recommendations could be made, more information was needed on the long term effects of residue harvest, including: 1) water quality; 2) soil biota; 3) transformations of different forms of soil organic carbon (SOC); and 4) subsoil SOC dynamics.[28] Current USDA Natural Resource Conservation Service (NRCS) practice standards for residue management do not recommend specific residue quantities and point to the use of the RUSLE2 model for guidance.[29] Despite broad recognition of the need for specific guidelines for residue removal, none yet exist.

With the upsurge in biofuels and the obvious prospects of removing significant quantities of residue, many questions remain regarding the long-term effects on soils from residue removal.

Residues have not yet been removed at the contemplated rates over a period sufficiently long for the effects to be clearly determined. Another difficulty is that while the effects of removing a residue may appear to one observer to have affected the soil in a certain manner, it may not be completely clear that the observed effects were fully related to the residue removal or, were in fact related to a change or to combinations of changes in other variables that were simply missed. A second observer may view the same results in an honest, but different manner. There are many variables and many different interactions among them that assigning effects is very difficult at best. There simply are no real-world data available for determining long-term effects. Nevertheless, we can describe some of the interactions that take place and how they can potentially affect soil health.

Soil erosion is an extremely important national issue. Most, if not all, agricultural cropland in the United States experiences some degree of soil erosion each year due to rainfall (water) and/or wind forces. Rainfall erosion (sheet and rill) occurs when rain directly strikes the soil, dislodging particles in the top layer.[C] When soil becomes saturated, particles are transported down the slope of the field. Soil erosion due to wind occurs in much the same manner as rainfall with wind forces dislodging soil particles and carrying them along and above the field surface (creep and saltation) or suspending them above the field.[D] While eroded soil does not disappear, the erosion process moves soil particles to other locations in the field (either downslope or downwind) where they can be transferred into waterways or onto non-croplands.

The amount of soil erosion that agricultural cropland experiences is a function of many factors: field operations (field preparation, tillage, etc.) in preparation for the next crop, timing of field operations, present throughout the year, soil type, field characteristics such as field slope, and the amount of residue (cover) left on the field from harvest until the next crop planting. Crop rotation cover provided by agricultural crop residues, both fallen and standing, helps to minimize rainfall and wind energy as it strikes or blows across the ground as well as helping to keep soil particles from being transported after they have been dislodged. Climatic conditions such as rainfall, wind, temperature, etc. must be accounted for. Studies predict that up to 30% of surface residue can be removed from some no-till systems without increased erosion or runoff.

The NRCS has established tolerable soil loss limits (T values) for all soil types in all counties throughout the United States. The tolerable soil loss values denote the maximum rate of soil erosion that can occur for a particular soil type that does not lead to prolonged soil deterioration and/or loss of productivity. Tolerable soil loss limits take into account the rate of topsoil formation, role of topsoil formation, loss of nutrients, erosion rate at which gully erosion would commence, and potential erosion-control factors that farmers would be able to implement. However, T values are not a function of the type of crop grown.

Another important aspect associated with soil conservation involves soil tilth. Soil tilth is defined as the physical condition of the soil as related to its ease of tillage, fitness as a seed bed, impedance to seedling emergence and root penetration, and all other physical conditions that

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[C] rill: A small intermittent watercourse with steep sides, usually only a few inches deep; www.hancockcoingov.org/surveyor/drainage_glossary_of_terms.asp.

[D] saltation: the movement of sand-sized particles by a skipping and bouncing action in the direction the wind is blowing influence crop development. Tilth depends upon soil granulation and its stability (soil workability) as well as organic matter content, moisture content, porosity, water retention, degree of aeration, rate of water infiltration, drainage, and capillary-water capacity, all of which are affected by crop residue removal. Preliminary values of required tilth have been estimated by the NRCS.

Various tillage operations are associated with management of agricultural crop residues and planting preparation throughout the year. Type and number of tillage operations employed for any particular crop from the time of harvest until the next planting have a tremendous effect on the amount of soil lost to erosion during the year, and hence, the amount of residue that can possibly be removed for energy purposes. It must be noted that even though crop residues may be used for energy purposes, the farmer is, first and foremost, in the business of producing grain. Therefore, he will be concerned with using those tillage operations that will provide him with the highest possible yield at the next harvest, and not necessarily those that tend to maximize erosion control on his lands.[30]

All agricultural cropland upon which nearly any crop is grown within a particular county can exhibit a wide variation in soil erodibility, field slope and length, climate conditions, and management practices. Within any one particular county there can be many different soil types (50 or more) used to grow agricultural crops. In addition, and possibly more importantly, not all soil types within a county may be suitable for agricultural crop production. Some soils possess characteristics that make them highly susceptible to erosion that may not be able to sustain certain cropping practices. Production of conventional agricultural crops on these lands may severely and/or permanently reduce the soil's ability to provide sustained, economical production. For this reason, the NRCS implemented a land capability classification (LCC) that ranges from I (one) to VIII (eight) that is applied to all soils within a county.

With added nitrogen fertilizers, residues can increase soil organic matter (SOM). However, roots appear to be the largest contributor to new SOM, making residues less important for carbon accrual. Residue removal leading to higher erosion and runoff rates would greatly decrease SOM and nutrients. Residue harvest may also require increased fertilizer inputs to make up for nutrients removed in the plant material. When returned to the land, crop residue also replenishes soil organic carbon (SOC) that typically has already been reduced 30 to 50% of precultivation levels through crop production activities. Soil organic carbon retains and recycles nutrients, improves soil structure, enhances water exchange characteristics and aeration, and sustains microbial life within the soil. It's been reported that crop yield and the value of environmental services (C and N sequestration) were greater for soils with greater SOC. Limited research has shown that removing stover reduces grain and stover yield of subsequent crops and further lowers soil organic matter levels.[31]

Residue removal can result in detrimental changes in many biological soil quality indicators including soil carbon, microbial activity, fungal biomass and earthworm populations, indicating reduced soil function. Some disease-producing organisms are enhanced by residue removal, others by residue retention, depending on crop and region. Residue cover can also reduce evaporation from the soil surface, thereby conserving moisture and increasing the number of days a crop can survive in drought conditions. Improved soil physical properties related to crop residues, such as reduced bulk density, e.g., the soil is looser and lighter, and greater aggregate stability, also lead to better water infiltration and retention.

In colder climates, residues are linked to reduced yields due to lower soil temperatures resulting in poor germination. Stubble mulching, as opposed to residue chopping, can help overcome this problem. Even though residue-associated yield reductions have been found on poorly drained, fine-textured soils, these soils often have low erosion risk and residues might safely be removed.

Despite the many important benefits of crop residues, research shows their effects can vary. For instance, some reports showed lower yields in systems with high crop residues due to increased disease or poor germination; others reported higher yields when soil moisture is limiting. Other studies suggest that residues do not contribute significantly to soil carbon. Many studies found that additional N fertilizer is needed when residues are left on soils to avoid N uptake (immobilization) from soil or allow for soil carbon accrual. For appropriate residue removal recommendations, the conditions leading to these varied effects of residues must be elucidated.

Soil health as related to residue removal is an extremely complex issue for which, as yet, there are no specific guidelines for residue removal. Wrong decisions, carried out over extended periods could have far reaching deleterious effects. Sustainable residue removal rates for biofuel production vary by system, according to such factors as management and cropping practice, crop yield, climate, topography, soil type and existing soil quality. Keeping in mind that gravimetric rates are not the same as percent soil cover (% mass is not the same as % coverage), appropriate conversion is necessary and varies by crop and region. While areas with low slopes and high yields may support residue harvest, in many areas the residue amounts required to maintain soil quality could be even higher than current practices. What is meant by ‘high’ and ‘low’ slopes has yet to be absolutely determined, which determination also depends on soil type and other cropping practices. Removal rates will need to be reduced as climates become warmer or more humid, for lower C:N residue or lower yielding crops, as soil disturbance (e.g. tillage) increases, or as soils become coarser textured, compared to the conditions in which most studies occurred (in the U.S. Midwest Corn Belt for no-till corn).[32] The most important aspect of this is that any or all of the interacting variables that determine how much residue can be removed, can, and usually do, change from year-to-year, across both wide regions of the country as well as across single counties and farms. A change in one variable nearly always changes how all the variables interact.

Given all the issues we’ve discussed regarding residue removal and soil health, rather than try to predict, county-by-county how much residue will be available, we assumed in our FASOM modeling that the available amount will be somewhere between 0% and 50%, at least until the issues we have discussed are settled. We based the amount removable based on the tillage practice: 0% removed for conventional tillage, 35% removed for conservational tillage, and 50% removed for no-till for corn stover.[33] Removal rates for wheat straw were based on the Billion Ton study.[34] We believe that given the uncertainties in removal rates, our assumptions are reasonable.

*Agricultural Residue Summary*

Corn and wheat are currently receiving the most attention across the industry due to their concentrated production areas and because they generate the majority of total residue produced. This also means they will more likely be able to support commercial scale production. In aggregate, the other residues provide fairly significant quantities of material, but because they are spread out, e.g., less densely planted both in the field and in a county or state, they are less likely able to support commercial operations.

We analyzed various reports on the availability of agricultural residues. These are summarized in Table 1.1-7. The agricultural residue estimates in Table 1.1-7 are based on historical/recent data, and thus, could be considered conservative in comparison to the future (2022) which would typically have higher crop yields or increases in acres harvested.

**Table 1.1-7. Estimated Agricultural Residue Feedstock Availability (per year)**[35,36,37,38,39]

| Source | Total Available | Total Removable Sustainably | Crops Analyzed |
|---|---|---|---|
| USDA | >500 million tons | not specified | Eight leading U.S. Crops, e.g. corn, wheat, soy, oats, barley, rice (did not specify other two) |
| NREL | 495 million tons | 173 million tons | Corn, wheat, soybeans, cotton, sorghum, barley, oats, rice, rye, canola, beans, peas, peanuts, potatoes, safflower, sunflower, sugarcane, and flaxseed |
| Gallagher | not specified | 156 million tons | Corn, wheat, sorghum, barley, oats, rice |
| Walsh | not specified | 144 million tons at $40/dry ton, ~150 million tons at >$40/dry ton for corn; 7 million tons at $40/dry ton, ~10-11 million tons at >$40/dry ton for wheat | Corn and wheat |
| Graham | 216 million tons | 65 million tons at 30% removal rate and current conditions; 112 million tons at 50% removal rate using no-till conditions | Corn |

Based on our FASOM modeling for the final rule, corn stover was the most economical agricultural residue projected to be used to produce ethanol in order to meet the 16 Bgal EISA cellulosic biofuel requirement. We estimate that by 2022 about 400 million wet tons of corn stover could be produced, see Table 1.1-8. Approximately 53 million dry tons of corn stover would be needed to produce the 4.9 billion gallons of cellulosic biofuel estimated to be used by our agricultural modeling in 2022.[E] Smaller amounts will be required from sugarcane bagasse, wheat residue, as well as sweet sorghum pulp (bagasse) to produce another 0.8 billion gallons of cellulosic biofuel.[F] Thus, the residue collected to meet EISA would be a small fraction of the total residue produced nationwide – though potentially higher fractions in some local areas. See Section 1.8.1.3 for more details on the use of agricultural residues for our cellulosic plant siting analysis developed for the air quality modeling.

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[E] Assuming conversion yield of 92.3 gal/dry ton as updated by NREL yields. Adjusted for moisture content, see FASOM documentation (Beach, 2010) for more details.

[F] Bagasse is technically a by-product of the sugarcane process and not an agricultural residue, we include it here for simplification. Sweet sorghum pulp is also a by-product of sweet sorghum processing.

# Table 1.1-8.
# FASOM Estimated Total Agricultural Residue Feedstock Possible in 2022 (million wet tons)[G]

| State/Region | Barley | Corn | Oats | Rice | Sorghum | Wheat | Total |
|---|---|---|---|---|---|---|---|
| Alabama | 0.0 | 1.2 | 0.0 | 0.0 | 0.1 | 0.6 | **1.9** |
| Arizona | 0.1 | 0.1 | 0.0 | 0.0 | 0.0 | 0.4 | **0.6** |
| Arkansas | 0.0 | 1.3 | 0.0 | 8.1 | 0.4 | 0.9 | **10.8** |
| California | 0.5 | 0.9 | 0.0 | 2.0 | 0.1 | 2.9 | **6.6** |
| Colorado | 0.5 | 6.3 | 0.1 | 0.0 | 0.7 | 9.9 | **17.4** |
| Connecticut | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | **0.0** |
| Delaware | 0.1 | 0.6 | 0.0 | 0.0 | 0.0 | 0.2 | **0.9** |
| Florida | 0.0 | 0.2 | 0.0 | 0.0 | 0.0 | 0.1 | **0.3** |
| Georgia | 0.0 | 5.5 | 0.1 | 0.0 | 0.2 | 1.5 | **7.2** |
| Idaho | 2.9 | 0.4 | 0.0 | 0.0 | 0.0 | 4.4 | **7.7** |
| Illinois | 0.0 | 65.3 | 0.1 | 0.0 | 0.3 | 3.6 | **69.2** |
| Indiana | 0.0 | 33.0 | 0.0 | 0.0 | 0.0 | 1.7 | **34.8** |
| Iowa | 0.0 | 79.1 | 0.3 | 0.0 | 0.2 | 0.1 | **79.7** |
| Kansas | 0.0 | 12.4 | 0.2 | 0.0 | 9.9 | 29.3 | **51.8** |
| Kentucky | 0.1 | 7.8 | 0.0 | 0.0 | 0.1 | 2.8 | **10.9** |
| Louisiana | 0.0 | 0.3 | 0.0 | 2.2 | 0.1 | 0.5 | **3.1** |
| Maine | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | **0.1** |
| Maryland | 0.2 | 1.7 | 0.0 | 0.0 | 0.0 | 1.0 | **2.9** |
| Massachusetts | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | **0.0** |
| Michigan | 0.0 | 9.2 | 0.1 | 0.0 | 0.0 | 3.7 | **13.1** |
| Minnesota | 0.3 | 39.7 | 0.3 | 0.0 | 0.0 | 4.2 | **44.6** |
| Mississippi | 0.0 | 1.2 | 0.0 | 1.1 | 0.3 | 1.1 | **3.8** |
| Missouri | 0.0 | 14.7 | 0.0 | 0.4 | 0.7 | 3.7 | **19.5** |
| Montana | 3.0 | 0.0 | 0.8 | 0.0 | 0.0 | 6.6 | **10.4** |
| Nebraska | 0.0 | 53.2 | 0.0 | 0.0 | 1.1 | 6.4 | **60.7** |
| Nevada | 0.1 | 0.0 | 0.0 | 0.0 | 0.0 | 0.2 | **0.3** |
| New Hampshire | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | **0.0** |
| New Jersey | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.1 | **0.1** |
| New Mexico | 0.0 | 0.6 | 0.0 | 0.0 | 0.7 | 1.6 | **2.9** |
| New York | 0.0 | 0.3 | 0.1 | 0.0 | 0.0 | 0.3 | **0.7** |
| North Carolina | 0.2 | 9.0 | 0.2 | 0.0 | 0.6 | 1.3 | **11.3** |
| North Dakota | 6.5 | 3.0 | 1.1 | 0.0 | 0.0 | 16.1 | **26.7** |
| Ohio | 0.0 | 15.1 | 1.1 | 0.0 | 0.0 | 3.9 | **20.0** |
| Oklahoma | 0.2 | 0.7 | 0.1 | 0.0 | 1.4 | 17.1 | **19.5** |
| Oregon | 1.3 | 0.1 | 0.4 | 0.0 | 0.0 | 0.3 | **2.1** |
| Pennsylvania | 0.0 | 0.1 | 0.0 | 0.0 | 0.0 | 0.9 | **1.1** |
| Rhode Island | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | **0.0** |
| South Carolina | 0.0 | 1.2 | 0.0 | 0.0 | 0.0 | 0.4 | **1.7** |
| South Dakota | 0.8 | 15.2 | 1.3 | 0.0 | 0.9 | 9.9 | **28.1** |
| Tennessee | 0.0 | 2.7 | 0.0 | 0.0 | 0.1 | 1.4 | **4.2** |
| Texas | 0.1 | 7.5 | 0.8 | 1.2 | 9.6 | 13.6 | **32.7** |
| Utah | 0.4 | 0.1 | 0.0 | 0.0 | 0.0 | 1.7 | **2.2** |
| Vermont | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | **0.0** |
| Virginia | 0.3 | 2.5 | 0.0 | 0.0 | 0.0 | 2.0 | **4.8** |
| Washington | 1.5 | 0.6 | 0.1 | 0.0 | 0.0 | 7.5 | **9.8** |
| West Virginia | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | **0.0** |
| Wisconsin | 0.1 | 12.9 | 0.4 | 0.0 | 0.0 | 1.2 | **14.7** |
| Wyoming | 0.5 | 0.2 | 0.1 | 0.0 | 0.0 | 0.6 | **1.4** |
| **Total** | **20** | **406** | **8** | **15** | **27** | **166** | **642** |

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[G] Assumes straw to grain ratio for barley and wheat (1.5:1) and for corn, oats, rice, and sorghum (1:1); Also assumes 0.024 ton/bu for barley and oats, 0.028 ton/bu for corn, 0.05 ton/cwt for rice and sorghum, and 0.03 ton/bu for wheat. For more details on assumptions please refer to the following: Beach, Robert; McCarl, Bruce, *U.S. Agricultural and Forestry Impacts of the Energy Independence and Security Act: FASOM Results and Model Description*, RTI International, January, 2010.

### 1.1.2.2 Dedicated Energy Crops

Crops developed and grown specifically as a renewable source of cellulosic material for biofuel production are not yet commercial, but have significant potential. Currently, crops such as corn that are grown and harvested for energy uses in the United States are also used for agricultural purposes and serve many important uses other than biofuel production. This competition could be reduced by the use of non-agricultural feedstocks for cellulosic biofuel production. Urban wastes and forest and agriculture residues could likely be the first feedstocks used in cellulosic biofuel production due to lower feedstock costs and availability; However, there are many uncertainties over land availability and sustainable removal rates for residues.

Many of the energy crops investigated are perennial species grown from roots or rhizomes that remain in the ground after harvesting the above-ground biomass. While most agricultural crops are annual species, perennials are considered beneficial in many ways. Dedicated perennial energy crops have the potential to grow on marginal lands, produce high yields, and may have low input needs. Once a perennial crop is established costs are reduced, as the need for tillage is lowered. The root system that remains in the soil can also facilitate the acquisition of nutrients thus decreasing the need for large fertilizer inputs. In southern climates, perennials have the potential for higher yield per acre of land than annual crops. This is due to the fact that perennial plants develop more quickly in the spring and the canopy of foliage can sustain for longer in the fall. This makes it possible for the plants to be more photosynthetically active and have a more efficient energy conversion system. Perennial energy crops also increase soil productivity, sequester carbon, and provide refuge for wildlife.

The following sections describe several of the most commonly discussed dedicated energy crops (switchgrass, miscanthus, and hybrid poplars) as well as some less familiarly known crops and the potential marginal lands on which they can be grown. While not all of these energy crops were specifically modeled in our agricultural models, switchgrass (which is often used as the main "model" energy crop), was projected to be a likely and significant feedstock for the production of renewable fuel to meet EISA.[H,40] For the final rule, FASOM projected that 7.9 ethanol-equivalent billion gallons out of the 16 billion gallon cellulosic biofuel required would come from switchgrass. See Chapter 5 for more details on the agricultural modeling.

*Switchgrass*

The energy crop that has received the most attention is switchgrass. Switchgrass is a perennial warm season grass that is native to the United States. It typically reaches heights of 3-5 feet, but can grow to more than 10 feet in some southern regions. It has a deep root system that extends many feet below the earth. It may be the ideal energy crop mainly because it can tolerate many soil types and climates from drought conditions to floods. It is also resistant to many pests and diseases. The photosynthetic pathway of switchgrass (and other perennials) allows it to produce high biomass yields with low amounts of chemical input. In the spring, switchgrass develops a photosynthetic canopy of biomass more quickly, and it also persists

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[H] Assuming 16 Bgal cellulosic biofuel total, 2.3 Bgal from Urban Waste; 13.7 Bgal of cellulosic biofuel for ag residues, forestry biomass, and/or energy crops would be needed.

longer in the fall than annual plants, allowing for a high net conversion of solar energy per year.[41]

Highly variable yields have been estimated at 1-12 dry tons/acre per year depending on soil, location, and variety. A yield of 4-5.5 dry tons/acre is a reasonable average today.[42] In a long term study sponsored by the DOE, average yield after 10 years of growth was 4.8-7.6 tons/acre for switchgrass when harvested annually.[I,43] Biannual harvests were also done experimentally to try and achieve the maximum yields possible but the harvests showed little difference in total yield. Biannual harvests resulted in approximately 70% of the yield for the first cut and 30% for the second.[44]

Water and nitrogen availability are the main resources that limit production of warm-weather grasses such as switchgrass. Nitrogen accessibility for these plants depends on many factors. Harvesting frequency, soil content, and removal rates all affect the nitrogen available to the plant. In a study by S.B. McLaughlin, initial nitrogen fertilization rates were 40-120 kg/ha (36-107 lbs/acre); however they discovered that a reduction to only 20 kg/ha (17.8 lbs/acre) of nitrogen was sufficient to produce similar yields in single cut systems in the mid-Atlantic region.[45] Reduced nitrogen amounts were similar in other regions of the country.

### *Miscanthus*

Miscanthus is a tall perennial grass that has been evaluated as a potential energy crop most extensively in Europe where it is already being grown for biofuel purposes. The genus is primarily tropic or sub-tropic in origin but there is a wide climactic range at the species level.[46] This characteristic makes it more suitable for establishment over the ranging climates of North America. Giant miscanthus (*Miscanthus x gigantus*) is a hybrid variety that can grow 12-14 feet tall. It is a cold-tolerant warm season grass and has similar characteristics to switchgrass with high yields and low amounts of input.[47] In the Midwest, the growing season of Miscanthus is April to October. The plant grows large green foliage that maximizes in approximately late August. As the temperature falls the foliage fades and drops off leaving the stem. The stem is the commercially important part of the plant and resembles bamboo. Stems can reach nine feet in length, ½ to ¾ in diameter, and are harvested in the winter after drying occurs.[48]

Establishment of a crop takes approximately 2 years, with maximum yields reached in the third year depending on soil fertility. In established crops 5-10 shoots per square foot can be developed. Yields in various studies from the University of Illinois were 9-16 tons/acre in various regions in Illinois. The southern regions of the state with poor soil quality also saw high yields illustrating that miscanthus is suitable for growth and high achievable yields on marginal land.[49] Yields in Europe ranged widely, with irrigated crops reaching 12 tons/acre and un-irrigated yields of 4-10 tons/acre in the fall. According to trials conducted in Europe, the quality of miscanthus biomass for conversion to biofuel improves by delaying harvesting until after the winter months and the plant has time to dry sufficiently. However, this reduced yields by 30 percent.[50] In comparison to switchgrass, research out of Illinois also concluded that miscanthus can yield more biomass for conversion to biofuel because of its even higher photosynthetic efficiency and longer growing season.[51] In terms of input, miscanthus uses nitrogen extremely

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[I] Switchgrass variety used in this study was Alamo. Other varieties could result in different yields.

efficiently and therefore does not need to be fertilized for high yields to be achieved. There is also no need for pesticides; however, herbicides have been used to control weed populations.[52]

Challenges in growing and producing miscanthus crop include high establishment costs, problems in winter survival during the first year, and potentially high water needs. European cost estimates are similar to other perennial plants at approximately $64 per dry ton; however they estimate that a growing cycle of 10-12 years is required to recover the start-up costs of $267 per planted acre.[53] The bulk of the high initial cost comes from planting and harvesting machinery. Establishment of a stronger market for growing these energy crops, as well as increased knowledge of propagation of the species, will inevitably lower overhead costs.[54]

### *Hybrid Poplar*

The poplar tree is another option being investigated for use as a dedicated energy crop. Woody perennial plants have some of the same characteristics of the perennial grasses that make them suitable for possible use as an energy crop. They retain significant amounts of root biomass below ground, require little tillage, grow fast large canopies, and require less fertilization than their agricultural counterparts.

Technological advances in harvesting and genetics may help produce species that will be more suitable for use as an energy crop. Genetic information has helped to understand the characteristics the poplar tree. The complex genetic information obtained from the genome of this plant will make possible the engineering of faster growing trees with more biomass available for harvest.[55]

### *Other Potential Feedstocks*

Several other perennial plants have the possibility to be used as dedicated energy crops. As previously described, the characteristics of perennial species make some optimal for use in this capacity. Because these plants have not been grown in agricultural sectors, they have not been extensively researched and fully optimized. Corn is a crop that has been scientifically studied for decades because of its continued importance in the market. Dedicated energy crops must see this type of investment to bring about further knowledge of basic biology which will lead to advances in breeding and eventual domestication of the species that have promise. The DOE along with university researchers have identified several other plants as potential energy crops. These include additional types of grasses such as reed canary grass, high biomass forage sorghum, and energy cane. Yields for forage sorghum are high and vary from 10-20 dry tons per acre depending on the genotype used.[56] High tonnage energy cane perhaps offers the greatest potential for much of East Texas and the U.S. Gulf Coast, as commercially grown varieties can produce up to 40 dry tons per acre under optimal conditions.[57] Hybrid willow, silver maple, black locust, sweetgum, and eucalyptus are other perennial woody plants that are possibilities.[58]

Significantly accelerated testing and selection for populations will be necessary in establishing these plants. Breeding for desired traits and adaptability across a wide array of environments in multiple physiologic and geographic regions will be necessary. No single species of dedicated energy plant will be optimal for all areas of the country, especially considering the amount of biofuels needed.  Temperature, rainfall, and soil composition are highly variable across the continental United States; therefore, using a diverse group of plant species optimal for each growing region is a likely strategy.  With current information and characteristics of each plant, the DOE has estimated where the possible growing areas could occur (see Figure 1.1-2). [59]

**Figure 1.1-2.**
**Possible Geographic Distribution of Dedicated Energy Crops**

*Marginal Land Assessment*

One of the benefits of perennial species is their suitability for growth on marginal lands. A study by Elliot Campbell of Stanford University assessed abandoned land availability and the potential for this land to be used for energy crops. [60]  Because of the increased demand for biomass energy, using abandoned crop or pasture lands to grow some of these crops could be a better alternative than converting forested areas or using agriculture lands.  This study estimated the amount of global abandoned land available, the amount of biomass that could be grown on these lands, and the corresponding use of that biomass for energy purposes.

Historical land use data, satellite imagery, and a global ecosystem model were used for the estimates.  The study considered “abandoned land” as land that was previously used for pasture or crops but has since been abandoned and not converted to urban or forested areas. Historical land use data was obtained from the History Database of the Global Environment 3.0 (HYDE) which consisted of gridded maps which show the fraction of crop and pasture land within each grid cell for decades between 1700 and 2000.  The Center for Sustainability and the Global Environment (SAGE) land use database was used to check and supplement the HYDE database.  They used a MODIS satellite map to exclude areas that have transitioned into forest or urban areas.  Two different mathematical approaches were then used to estimate a conservative and a high estimate of total land available.  Biomass production was estimated using the Carnegie-Ames-Stanford Approach ecosystem model which takes into account climate data, soil texture, land cover and the normalized difference vegetation index (NDVI), but does not take into account fertilizer use or irrigation, which could increase yields.

The low and high estimates for global abandoned land, excluding forested and urban areas are 951 and 1166 million acres. The authors found that these lands could produce between 1.6 and 2.1 billion tons of biomass respectively. In the United States an average of approximately 146 million acres of abandoned land was estimated. Assuming natural growth on these lands, approximately 321 million tons/year of biomass could be produced. At just 80 gallons of ethanol per ton of biomass, there could be the potential to produce approximately 26 billion gallons from a grass crop such as switchgrass. It is pointed out that there will be significant differences between crop types and management styles which will effect growth and yields. Although perennial grasses can be grown on these lands, yields may be lower than they would be on more suitable agricultural lands.

On a state-by-state basis, the areas with the highest amount of available abandoned lands are in the West. Texas has the largest amount of abandoned land estimated at 10.37 million acres. Wyoming, Utah, Oregon, New Mexico, Nevada, Colorado and California each contribute over 5 million abandoned acres to the total. Midwestern states including Iowa, Wisconsin, Illinois, and Ohio have approximately 3-4 million acres of abandoned land each (see Table 1.1-9). These lands may be more conducive to crop production than the more arid parts of the West. However, the condition and quality of these lands is unknown at this time. It would be difficult to estimate the specific types of energy crops that could be grown on these lands. Also, in the DOE assessment previously referenced, most of the Western states are not implicated as areas of possible biomass growth (above Figure 1.1-2).

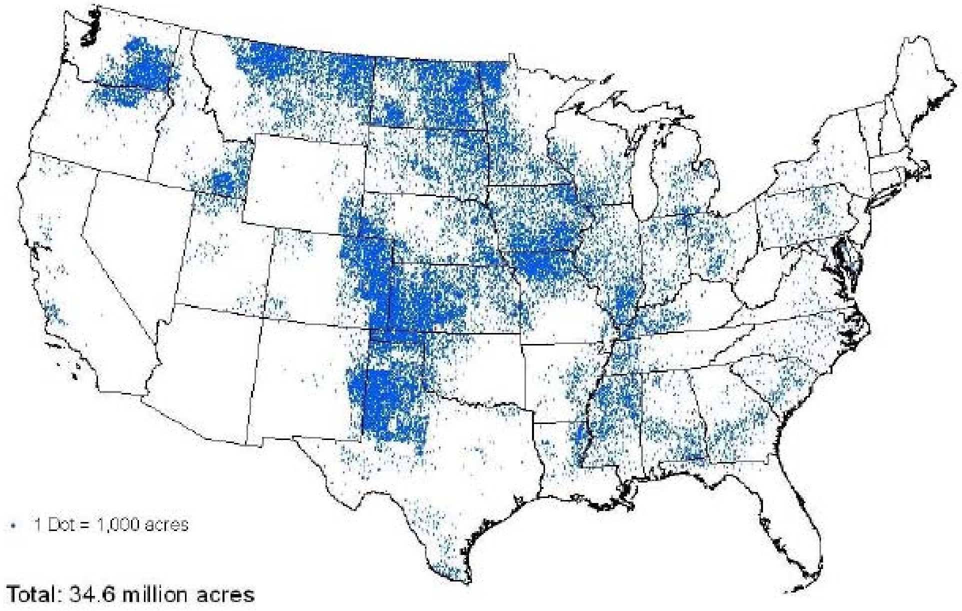
## Table 1.1-9. Abandoned Agriculture Land and Potential Production by State[61]

| State | Area (Million ha) | Area (Million acres) | Production (MM tons biomass/yr) | Ethanol Production Rate (gallons/tons) |
|---|---|---|---|---|
| Alabama | 1.4 | 3.46 | 13.2 | 3.82 |
| Alaska | 0.3 | 0.74 | 0.4 | 0.54 |
| Arizona | 1.9 | 4.69 | 2.4 | 0.51 |
| Arkansas | 1.1 | 2.72 | 11.1 | 4.09 |
| California | 3.6 | 8.89 | 13.2 | 1.48 |
| Colorado | 2.7 | 6.67 | 8.1 | 1.21 |
| Connecticut | 0.1 | 0.25 | 0.6 | 2.43 |
| Delaware | 0.1 | 0.25 | 0.5 | 2.02 |
| District of Columbia | 0 | 0 | 0 | 0 |
| Florida | 0.5 | 1.24 | 2.7 | 2.19 |
| Georgia | 1.6 | 3.95 | 15.2 | 3.85 |
| Idaho | 1.4 | 3.46 | 4.7 | 1.36 |
| Illinois | 1.6 | 3.95 | 11.4 | 2.88 |
| Indiana | 1.2 | 2.96 | 8.5 | 2.87 |
| Iowa | 1.6 | 3.95 | 12.7 | 3.21 |
| Kansas | 0.3 | 0.74 | 1.8 | 2.43 |
| Kentucky | 0.8 | 1.98 | 6.7 | 3.39 |
| Louisiana | 0.9 | 2.22 | 7.8 | 3.51 |
| Maine | 0.1 | 0.25 | 0.8 | 3.24 |
| Maryland | 0.4 | 0.99 | 2.7 | 2.73 |
| Massachusetts | 0.2 | 0.49 | 1.1 | 2.23 |
| Michigan | 1.5 | 3.71 | 9 | 2.43 |
| Minnesota | 1.6 | 3.95 | 10.7 | 2.71 |
| Mississippi | 1 | 2.47 | 9.1 | 3.68 |
| Missouri | 1.5 | 3.71 | 14.1 | 3.81 |
| Montana | 1.7 | 4.2 | 6.8 | 1.62 |
| Nebraska | 0.4 | 0.99 | 2.2 | 2.23 |
| Nevada | 2.1 | 5.19 | 3 | 0.58 |
| New Hampshire | 0 | 0 | 0.3 | 0 |
| New Jersey | 0.2 | 0.49 | 1.9 | 3.85 |
| New Mexico | 3 | 7.41 | 5.4 | 0.73 |
| New York | 1.7 | 4.2 | 10.2 | 2.43 |
| North Carolina | 0.7 | 1.73 | 6.2 | 3.59 |
| North Dakota | 1 | 2.47 | 4.4 | 1.78 |
| Ohio | 1.4 | 3.46 | 8.9 | 2.57 |
| Oklahoma | 1.1 | 2.72 | 8.8 | 3.24 |
| Oregon | 2.2 | 5.43 | 8.2 | 1.51 |
| Pennsylvania | 1 | 2.47 | 8.2 | 3.32 |
| Rhode Island | 0 | 0 | 0.2 | 0 |
| South Carolina | 0.8 | 1.98 | 7.3 | 3.69 |
| South Dakota | 0.3 | 0.74 | 2 | 2.7 |
| Tennessee | 1.1 | 2.72 | 10.3 | 3.79 |
| Texas | 4.2 | 10.37 | 25.3 | 2.44 |
| Utah | 2.6 | 6.42 | 4.7 | 0.73 |
| Vermont | 0.1 | 0.25 | 1 | 4.05 |
| Virginia | 0.7 | 1.73 | 6.7 | 3.88 |
| Washington | 0.9 | 2.22 | 4 | 1.8 |
| West Virginia | 0.1 | 0.25 | 0.5 | 2.02 |
| Wisconsin | 1.4 | 3.46 | 9.9 | 2.86 |
| Wyoming | 2.8 | 6.92 | 6.1 | 0.88 |
|  |  |  |  |  |
| Totals | 58.9 | 145.5 | 321 |  |
|  |  |  |  |  |
| Total Ethanol Volume[a] |  |  |  | **25.68 Bgal Ethanol/yr** |

a. Assuming a conservative 80 gal/ton conversion rate

The estimates of abandoned agricultural land do not include land enrolled in the Conservation Reserve Program (CRP), which could be an additional source of land available for energy crops. Land in this program is farmland that is converted to trees, grass, and areas for wildlife cover, but is considered crop land by the models in the abandoned land study. Environmental benefits of this land include the creation of wildlife habitat, increasing soil productivity, reducing soil erosion and improving ground and surface water quality.[62] As of November 2009, there were 31.2 million acres under the CRP contract which is down 2.6 million acres from the prior year.[63] Approximately 28 million CRP acres are growing with native or introduced grasses, suggesting that there is a significant amount of switchgrass already in the environment. Figure 1.1-3 shows the land allocation in the United States in 2008.[64] Recently, the 2008 Farm Bill capped the number of acres in the CRP at 32 million acres for 2010-2012. Following historical trends, it is possible that some of these acres will go into crop production. While some of this land may go for biofuel production, the benefits of producing energy crops will have to be weighed against the benefits of having the land in the CRP.

**Figure 1.1-3. 2008 CRP Enrollment**



### 1.1.2.3 Wood Residues

There is a substantial amount of forestland here in the U.S. It is estimated that 749 million acres, or one-third, of the U.S. land area is forested. Of this forested land, two-thirds (504 million acres) is considered timberland which contains more than 20 $ft^3$ of woody material per acre – the other one-third of the forest land contains less than 20 $ft^3$ of woody material per acre. Most of this forested land, 58 percent, is privately owned, another 29 percent of the forest land is publicly owned, and 13 percent is owned by the forest industry. A higher percentage of the land is privately owned in the East, and a higher percentage of the land is publicly owned in the West.

Of the 749 million acres of forestland, 77 are reserved as parks or wilderness and would likely be considered off limits for harvesting for biomass. Also, 168 million acres of timberland is considered not suitable for harvesting for biomass because of poor soil, lack of moisture, high elevation, or rockiness.[65]

The U.S. forestry industry harvests a portion of this forest land to produce its products, and in the process of doing so, it generates woody residues that can be recovered for the purpose of producing cellulosic biofuels. Major sources of solid waste wood generated in the U.S. include forestry residues, primary and secondary mill residues, and urban wood residues. All this material is being produced through the everyday practices of the forestry industry providing its primary wood products to the various industries it supplies. In addition, forests which are not currently harvested for wood could be thinned. This thinning of the forests would not just be to provide biomass, but as part of a strategy which may be beneficial for the forests, or to avoid external costs such as forest fires. Each of these categories is further described below:

*Forestry residues*

In-forest operations generally include four major sources of materials: logging residues, other removals, fuelwood, and fuel treatment wood.[66] In the process of removing, or logging, the larger woody portion of the trees (5 inch diameter and greater), the logging industry creates logging residues. Logging residues typically include tops of harvested trees and unwanted trees cut or knocked down and left on site, including dead and cull trees. Other removals are growing stock and other sources cut and burned or otherwise destroyed in the process of converting forest land to non-forest uses, such as for making way for new housing or industrial developments. They also include growing stock removed in forestry cultural operations. Forest residues are also available from fuelwood, which is harvested wood used in the residential and industrial sectors for energy. Thus, forest residues are already being created or harvested today.

*Primary and secondary mill residues*

Harvested wood from forests is converted into consumer products at wood processing mills. Primary mills convert roundwood products (i.e., tree trunks and logs) into other wood products, including sawmills that produce lumber, pulp mills, veneer mills, etc. Secondary mills use the products from primary mills to produce other products such as millwork, containers and pallets, buildings and mobile homes, furniture, flooring and paper and paper products. While primary and secondary mills are typically separate facilities, both primary wood processing and secondary conversion to finished consumer products can occur in the same facility.[67] Both primary and secondary mills produce residue and woody waste material. For example, the residue generated by primary mills includes bark, slabs and edgings, sawdust and peeler cares. This waste material could be used as feedstock to produce biofuels.

*Urban wood residues*

The two principal sources of urban wood residues are municipal solid waste (MSW) and construction and demolition (C&D) debris. Municipal solid waste contains solid wood from both wastewood and yard trimmings. Yard trimmings include herbaceous material and woody trimmings. Construction waste is made of contemporary building materials with little contamination. Sources include new residential construction, new nonresidential building construction and repair and remodeling of existing buildings. Demolition waste, on the other hand, is a heterogeneous mixture of material from demolishing buildings and structures and is difficult to remove uncontaminated portions. The potential contribution of urban wood residues to the production of biofuels is discussed in the Section 1.1.2.4 of this RIA.

*The Thinning of Forests*

While the above categories are associated with existing forest harvesting or other removal activities, the thinning of forests would largely be a new activity. Many U.S. forests have become overgrown and very dense with forest material, and a portion of this overgrown forest will die, dry out and decay. This decaying forest material can provide a source of fuel for forest fires that are expensive to fight or contain. Over the previous 10 years forest fires have consumed 49 million acres and cost the U.S. taxpayer $8.2 billion.[68] This cost does not include the additional cost due to the loss of human life, the loss of personal property and the impact on the environment. Thinning forests involves the removal of excess forest material from the forests that could help to prevent some of these forest fires, or at least help to reduce their impact. Also, thinning these forests to prevent them from becoming overly dense could potentially help them to remain healthier. There are many thinning operations today, but the material is burned or left to decompose instead. The removed excess woody material from overgrown forests could provide a source of biomass for producing biofuels.

*Accessibility of Wood Residues*

Despite the availability of woody residues for producing cellulosic biofuels, there are several obstacles for woody residues that are not present when utilizing feedstocks such as agricultural residues. For instance, forestlands will likely be managed less intensively than agricultural lands because forests provide multiple-use benefits (e.g., wildlife habitat, recreation, and ecological and environmental services).[69] This in effect makes it more difficult to take steps to increase the productivity of forest areas. Also, there are factors or site conditions that can affect tree growth, including poor soils, lack of moisture, high elevation, and rockiness. The limits caused by some of these factors would likely not be overcome, resulting in lower productivity than what could be theoretically possible. Also, a couple of these factors, the high elevation and rockiness, results in areas of forestland which is inaccessible by forestry equipment. Forestry residues are also demanded for other purposes other than for production of a transportation fuel (e.g. for process fuel). These reasons would make it more challenging to collect and use woody residues in large quantities compared to agricultural residues.

On the other hand, there may be some benefits to the use of woody residues. One example is the removal of excess forestry biomass to reduce the risk of fires and/or to improve forest health. In addition, resources such as primary and secondary mill residues and urban wood residues are already collected at the processing facility and it seems probable that some cellulosic facilities could be co-located to mills and/or landfills to increase the likelihood of having close and steady feedstocks readily available. Some states may also be endowed with larger wood resources than agricultural residues.

In making estimates of potential forest residue availability, certain assumptions about accessibility and recoverability are typically made. For example, some studies assume that residue collection is completed at the same time as harvesting, meaning that all residues are regarded as one hundred percent accessible.[70] This might become possible due to integrated harvesting systems which could harvest forest biomass in a single pass operation such that residual forest residue for producing biofuels could be produced along with conventional forest products.[71] Other estimates for accessibility have been lower, with about sixty percent of North American temperate forest considered accessible (not reserved or high-elevation and within 15 miles of major transportation infrastructure).[72] In terms of recoverability, some studies have assumed sixty-five percent of logging residues and fifty percent of other removal residues as being recoverable while others report an average potential recovery of sixty percent and as much as sixty-five percent when utilizing newer technology.[73] Refer to Section 1.3 for more discussion on the harvesting and transport of wood residues.

*Sustainable Removal*

While there has been some discussion of sustainable removal practices for crop residues, there has been less review on the topic for woody residues. As forest residues have been traditionally left in the forest to decompose, there remains much to be learned about the harvesting of forest residues in a sustainable way that still leaves sufficient nutrients to maintain the forest and to replenish the soil. This is reiterated in reports on woody residue removal which emphasize the need for more detailed studies on the range of ecological effects, from wildlife to soils.

Currently, practices for how much forest residue should be maintained in the forest to maintain forest health vary substantially. For example, a district for one study on the removal of forestry residues required about 5 tons per acre be left whereas other districts had no such requirements.[74] In a different source, a summary of national forest land management plans from 1995 indicated about 60 percent of western national forest timberland base to be suitable for timber production operations.[75] This issue is not only applicable in the United States, but also in Europe, where the use of forest biomass for energy is also being considered. A Swedish study showed that the main incentive for forest owners not to sell forestry residues was concerns for soil fertility.[76] Therefore, although there have been suggested limitations to the amount of residue suitable for removal there has yet to be consensus over the optimal amount.

Some recent long-term soil productivity studies are beginning to provide some useful data post-harvesting. One study, which assessed the soil condition 5 years after harvest of the woody biomass, showed that for most of the sites there was not a significant impact on soil carbon and nitrogen and compaction, while at one site there was a significant reduction of soil carbon and nitrogen. Another study which tracked the soil quality 10 years after harvesting the forest biomass came to some interesting conclusions.[77] Complete removal of the surface organic matter did lead to declines in the concentration of soil carbon, however, this effect was attributed to the loss of the forest floor. Soil compaction did reduce productivity in clay soils, but increased the productivity in sandy soils, and was not a factor if an understory was present.[78] Thus, these two studies suggest that forestry operations, if they are designed for the soil type and the area that the operations are taking place, may be designable to protect the sustainability of forests. However, additional studies and data review is likely necessary to fully understand these impacts.

Yet another issue regarding sustainable removal is the affect of forest residue extraction on biodiversity. The removal of forest residue may affect biodiversity because lower amounts of wood in the forest imply fewer habitats for species using wood for breeding. Species may also be threatened because certain insects colonize in wood that may be burned for energy purposes. Several forestry management methods, such as lower planting densities, aggressive thinnings, prescribed burning, and longer rotations have been suggested as ways to maintain biodiversity in actively managed forests.[79] Quantitative predictions about how much habitat loss various species can tolerate are almost impossible to make. Instead, one study recommended making qualitative predictions on which types of habitats or wood types are most threatened. For instance, this study examined Sweden’s forest fuel extractions and concluded that coniferous wood can be harvested to a rather large extent, whereas deciduous tree species should be retained to a larger degree.[80] Another study in the southern Appalachians suggests that selective harvesting to maintain a forest with regions of many different ages and structural classes is key to maintaining biodiversity.[81] As different regions will certainly have species specific to their own regions, more research is necessary to determine appropriate recommendations on maintaining biodiversity.

Another issue that has been considered is the occurrence of soil disturbance due to the use of forest residue collection equipment. Studies have shown that the growth of woody plants and yields of harvestable plant products are decreased by soil compaction from residue collection equipment, because of the combined effects of high soil strength, decreased infiltration of water and poor soil aeration.[82] In another study, the use of a residue bundling machine caused some measurable amounts of soil disturbance and an increase in “soil exposed” area at some locations.[83] Thus, it is important to limit the severity of soil disturbances with minimal passes and relatively low ground pressure.

### *Energy Content of Forest Residue and Biofuel*

Woody material obtained by the harvesting or thinning of forest is somewhat more energy dense compared to other forms of biomass. On its Biomass Program webpage, the Department of Energy lists the higher heating values (lower heating values were not available) for many different types of biomass for dry samples.[84] These values for woody biomass are summarized in Table 1.1-10.

**Table 1.1-10. Energy Content of Forest Material**

| **Tree name** | **Higher Heating Value (BTU/lb dry wood)** |
|---|---|
| Hybrid Popular | 8,384 - 8,491 |
| Black Locust | 8,409 - 8,582 |
| Eucalyptus | 8,384 - 8,432 |
| American Sycamore | 8,354 - 8,481 |
| Eastern Cottonwood | 8,431 |
| Monterey Pine | 8,422 |

Because woody material is energy dense, it can produce a large amount of renewable fuel per ton of feedstock. Based on recommendations from our cellulosic modeling efforts with the National Renewable Laboratory (NREL), we assumed 101.5 gallons of ethanol could be produced per ton for hardwood feedstocks in 2022. This is 10 percent more than the yield of 92.3 gallons of ethanol per ton used for agricultural residues and switchgrass. The reasoning for the higher yields for hardwoods is their potential for higher carbohydrate compositions and thus more sugars available for conversion to ethanol. These yields were used in our forest and agricultural modeling as described in Chapter 5. NREL also completed a more recent feedstock analysis indicating that yield differences may be smaller, i.e. closer to 95 gal/dry ton for hardwoods. This work will be beneficial as we continue to make improvements to our analyses in the future. For more information on feedstock considerations and their impacts on biorefining refer to the NREL report in the docket.[85]

### *Availability of Forest Residue*

The quantity of forest residue available to produce biofuels was estimated by two different studies. We summarize those two studies, and then summarize data which we received directly from the U.S. Forest Service. In addition, we were able to incorporate the forestry sector component in the FASOM model, as further described in Chapter 5. As these feedstocks are now allowed to compete with the various agricultural feedstocks and energy crops in the market, we believe it is a more robust analysis than our prior proposal method of analyzing the agriculture and forestry sectors separately. Therefore, our final rule is based on results taken from our forest and agricultural modeling in FASOM.

### *Billion Ton Study*

A landmark assessment of the potential biomass available from existing forest land in the U.S. was recently conducted by the USDA and the Department of Energy (DOE).[86] This landmark assessment was titled “Biomass as Feedstock for a Bioenergy and Bioproducts Industry: The Technical Feasibility of a Billion Ton Supply,” which is also known as the Billion Ton Study. We reviewed this study and are summarizing much of the information contained in that report here because it is very useful background about U.S. forest land and its potential contribution to biofuels production.

The total forest inventory is estimated to be about 20.2 billion dry tons. The report authors estimated that about 2.2 percent of the total forest inventory is harvested each year, which corresponds to 444 million dry tons. This removal rate is estimated to be less than the annual average forest growth, which suggests, at least on an aggregate basis, that this removal rate is sustainable. It is estimated that 78 percent of this removal was for roundwood products (sawlogs, pulpwood, veneer logs and fuel wood), 16 percent was logging residue and about 6 percent was classified as other removals. Thus, the Billion Ton study authors estimate that 67 million dry tons of logging residue could potentially be available for biofuel production, which is comprised of 49 million dry tons of primary logging residue, and 18 million dry tons of other removals. The Billion Ton study estimates that 65 percent of the total logging and other residue would be recovered for use. The two reasons cited for not collecting the other 35 percent is that some of the logging residue is comprised of small pieces, such as small branches and leaves, which would not be economically recoverable, and that it would be necessary to leave behind a portion of the logging residue to protect the sustainability of the forest as well as the wildlife which thrives in the forest. For these reasons, the Billion Ton Study authors estimated that 41 million dry tons of forest residue could be sustainably removed from the U.S. forests as byproduct from existing logging operations. Virtually all this removal is from privately owned land where the logging operations occur today.

Additional forest residue is available downstream of the logging operations at mills. In the process of making their products, primary wood processing mills create some wood residue. However, almost all of this waste wood is recovered or burned for process heat. For example, the bark from the logged wood is burned as fuel or converted into mulch. The Billion Ton authors estimated that just under 2 million dry tons per year of residue would be available from the primary wood processing mills as feedstock for producing biofuels.

The Billion Ton study estimated that additional wood waste could also be available from secondary wood processing mills, which refine crude wood into more refined products. The report authors could not find any data on how much residue is produced by these secondary wood processing mills, however, a study of these facilities did provide an estimate. Approximately 15.6 million dry tons per year were estimated to be available from the smaller of these secondary wood processing mills, however, the report estimated that only 40 percent, or 6 million dry tons per year, would be available for biofuels production.

Another industry which processes harvested wood is the pulp and paper mill industry. These companies process wood into fiber to make paper and cardboard. Most of the pulp and paper mills use the Kraft process or sulfate pulping process which converts half of the woody material into fiber, while the other half is a byproduct termed black liquor. The black liquor contains a substantial amount of biomass. The pulp and paper industry is already using all of this black liquor, plus purchasing and using some fossil fuels, to generate the electricity and heat that it needs for its plants. Therefore, the authors of the Billion Ton Study estimated that there would not be any residue available from the pulp and paper industry to produce biofuels.

The Billion Ton study estimated that another potential source of biomass from forests would be the selective thinning of forests to help reduce the risk of fire, or to facilitate the fighting of fires in the case that fires break out. Using a forest evaluation tool called the Fuel

Treatment Evaluator, the Forest Service estimated tree densities for forests all across the U.S. and identified forests which contain excess woody material. The forests which contain excess woody material are candidates for providing additional biomass for producing biofuels. The Forest Service estimated the total amount of excess woody material to be 8.4 billion dry tons.

The Forest Service next estimated the portion of this excess woody material that could be harvested for biofuels production. Despite the fact that this inventory exists today, the Billion Ton Study authors assumed that this excess woody inventory would be used over a 30 year period to reflect a sustainable removal rate. This assumption reduces the total yearly available amount of excess woody biomass to 280 million dry tons per year. Another limiting factor is that much of our nations forest is remote, thus, only 60 percent of this excess woody material was estimated to be removable for use. The next assumption made is that the best of this woody material, which is the woody material more than 5 inches in diameter and which comprises 70 percent of this material, would be used for feedstock for the logging industry. Thus, the remaining 30 percent would be residue that would serve as feedstock for the biofuels industry. Finally, the last assumption made is that of the excess woody material harvested, 15 percent would be lost between harvesting and use, thus the total amount of woody biomass was adjusted to be 15 percent lower. These assumptions result in 18 million dry tons of additional woody biomass that could be used to supply the biofuels industry annually, and 42 million dry tons that would supply the logging industry.

As shown below in Table 1.1-11, the Billion Ton Study estimates that a total of 67 million dry tons per year would be available from non-urban forests. It is important to note that not all of the forest biomass in the Billion Ton Study, specifically wood from national forests and perhaps much of the fuel wood, would be eligible to be used as a qualifying biofuel feedstock under the RFS2 program. Despite this limitation, the Billion Ton Study is an important source of information, especially when considering the maximum amount of sustainably removable forest biomass.

**Table 1.1-11.**
**Quantity of Forest Biomass Available for Producing Biofuels**

| | Quantity (million dry tons) |
|---|---|
| Logging Residue | 41 |
| Primary Mill Residue | 2 |
| Secondary Mill Residue | 6 |
| Forest Thinnings | 18 |
| Total | 67 |

The Billion Ton Study authors projected that forest harvesting and mill activity will increase in the future, thus increasing the amount of forest residues that would be available for producing biofuels. The authors estimated the future forest residue supply in the year 2050 and concluded that the logging residue is expected to increase from 41 million dry tons to 64 million dry tons. Also in 2050, the primary and secondary mill residue quantity is projected to increase from a total of 8 million dry tons per year to a total of 24 million dry tons per year. No estimate was provided for any increase, or decrease, in the amount of forest woody material that would be available from thinning forests. If the projected 39 million dry ton increases in forest residue comes to fruition, then the total amount of forest residue that would be available for producing biofuels in 2050 would be 106 million dry tons per year. We are primarily interested in compliance with the RFS2 biofuels standard in 2022, which is just over 1/3rd of the way between today and 2050. Thus, by interpolating the projected future forest residue in 2022 relative to current levels and those in 2050, the report supports the conclusion that 79 million dry tons of forest residue would be available in 2022.

*U.S. Cellulosic Biomass Study*

Another estimate for the amount of forest residue that could be used to produce biofuels was made by Marie Walsh in a report titled "US Cellulosic Biomass Supplies and Distribution".[87] This report also uses the Forest Service data base for its estimates, so its conclusions resemble those of the Billion Ton study. However, an important difference between this Cellulosic Biomass Study and the Billion Ton Study is that Marie Walsh estimated a cost curve for the amount of biomass available for her Cellulosic Biomass study for multiple future years.

In this report, Marie Walsh estimates that 63 million dry tons of logging residue is created in the lower 48 states. Of this total amount of logging residue, 65 percent is estimated to be accessible by roads, and not all the accessible logging residue is considered recoverable because some of it is too small to recover. This study also estimates the cost for recovering this available logging residue for future years for five year intervals through 2030. The amount of logging residue available at different price points and for different years is summarized in Table 1.1-12.

**Table 1.1-12.**
**Quantity of Logging Residue Available at Varying Prices**
**(million dry tons)**

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | $20/dt | $25/dt | $30/dt | $35/dt | $40/dt | $45/dt | $50/dt | $75/dt | $100/dt |
| 2007 | 0.06 | 1.84 | 6.22 | 10.89 | 24.02 | 31.29 | 31.29 | 36.19 | 38.50 |
| 2010 | 0.065 | 1.81 | 6.41 | 13.23 | 29.37 | 38.70 | 38.70 | 45.02 | 47.89 |
| 2015 | 0.065 | 1.95 | 6.80 | 13.62 | 29.99 | 39.35 | 39.35 | 45.71 | 48.60 |
| 2020 | 0.067 | 2.10 | 7.22 | 14.41 | 31.51 | 41.20 | 41.20 | 47.79 | 50.77 |
| 2025 | 0.067 | 2.17 | 7.46 | 14.81 | 32.32 | 42.19 | 42.19 | 48.90 | 51.95 |
| 2030 | 0.068 | 2.25 | 7.70 | 15.22 | 33.12 | 43.17 | 43.17 | 50.01 | 53.13 |

To qualify under RFS2, the biofuel producer would need to show that the forest residue is from a qualifying planted forest as specified under RFS2. This could limit the quantity of biomass available under RFS2 to lower levels that those shown in the table.

Marie Walsh also identified the quantity of woody material that would be available at specific prices from other removal supplies – trees removed to make way for the construction of buildings. Marie Walsh estimates that a total of approximately 24 million dry tons of forest residue falls within this category. She estimated that perhaps 50 percent of this material would be available for biofuel production. Marie Walsh added the other removal supplies to the logging residue and estimated their availability at different price points, increasing the available biomass by 25 percent. The combined total is summarized in Table 1.1-13.

**Table 1.1-13.**
**Quantity of Forest Residue and Other Removals Available at Varying Prices**
**(million dry tons)**

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | $20/dt | $25/dt | $30/dt | $35/dt | $40/dt | $45/dt | $50/dt | $75/dt | $100/dt |
| 2007 | 0.09 | 2.63 | 10.49 | 15.16 | 32.16 | 41.62 | 41.62 | 47.71 | 50.49 |
| 2010 | 0.09 | 2.63 | 10.76 | 17.59 | 38.08 | 49.17 | 49.17 | 56.68 | 60.03 |
| 2015 | 0.09 | 2.79 | 11.26 | 18.08 | 38.87 | 50.00 | 50.00 | 57.56 | 60.93 |
| 2020 | 0.09 | 2.96 | 11.80 | 19.00 | 40.58 | 52.04 | 52.04 | 59.84 | 63.31 |
| 2025 | 0.10 | 3.07 | 12.15 | 19.50 | 41.56 | 53.21 | 53.21 | 61.15 | 64.68 |
| 2030 | 0.10 | 3.17 | 12.51 | 30.02 | 42.55 | 54.39 | 54.39 | 62.47 | 66.07 |

To qualify under RFS2, the biofuel producer would need to show that the "other removal supplies" that it is interested in purchasing would qualify under RFS2. Some of this category could quality as MSW while another portion of it may qualify if the trees are being removed to prevent a wildfire from damaging the nearby buildings. However, the RFS2 definitions could limit the quantity of this category of biomass that could qualify under RFS2.

This report also estimates the amount of primary and secondary mill residues available for biofuels production. Like the Billion Ton study, Marie Walsh also concludes that only a very small amount of primary mill residue is estimated to be currently unused and available for producing biofuels. She concludes that out of the 88.7 million dry tons of primary mill residue which are generated, that only 1.3 million dry tons is not used for fuel, fiber or other sources as discussed above. However, she provides an additional assessment that, at the right price, the primary mill residue could be drawn away from these other users of the primary mill residue. The assumption is that for fiber uses, the primary mill residue could be drawn away from the current users at 35% of the product price. For other uses, including for fuel, it is assumed that at 65% of the market price of the raw wood value, the primary mill residue could be purchased away from the current users. Table 1.1-14 below estimates the price that specific estimated primary mill residue volumes could be available for producing biofuels.

**Table 1.1-14.**
**Quantity of Primary Mill Residue is Available at Varying Prices**
**(million dry tons)**

| | $20/dt | $25/dt | $30/dt | $35/dt | $40/dt | $45/dt | $50/dt | $75/dt | $100/dt |
|---|---|---|---|---|---|---|---|---|---|
| 2007 | 0.43 | 4.93 | 6.03 | 19.34 | 20.14 | 41.46 | 42.38 | 50.31 | 51.04 |
| 2010 | 0.55 | 5.70 | 7.29 | 21.91 | 22.80 | 46.03 | 47.37 | 56.29 | 57.33 |
| 2015 | 0.56 | 5.93 | 7.51 | 22.88 | 23.77 | 48.00 | 49.34 | 58.55 | 59.61 |
| 2020 | 0.58 | 6.16 | 7.74 | 23.85 | 24.73 | 49.97 | 51.31 | 60.82 | 61.88 |
| 2025 | 0.59 | 6.34 | 7.93 | 24.58 | 25.47 | 51.46 | 52.82 | 62.55 | 63.61 |
| 2030 | 0.60 | 6.52 | 8.12 | 25.31 | 26.20 | 52.96 | 54.31 | 64.28 | 65.35 |

The author also attempted to estimate the amount of secondary mill residue that could be available for producing biofuels. She observed that data is scant on the amount of secondary mill residue. She referenced a study (Rooney, 1998) that estimated that only a very small volume of secondary mill residue would be available for producing biofuels. Of 12.5 million dry tons of secondary mill residue which is generated, only 1.2 million dry tons is available for producing biofuels. Unlike the analysis conducted for primary mill residue, the author did not attempt to estimate the extent that biofuels producers could bid the secondary mill residue away from the current users.

Marie Walsh also assumes that three very difficult-to-quantify sources of forest material could be available as biomass for producing biofuels. One of these potential sources is the forest material that could be available through the thinning of overgrown forests to help reduce the fire risk within these forests. Marie Walsh referenced one study which estimated that 100 to 200 million acres of overgrown forest could be harvested. No estimate, however, was provided for the amount of this forest material that could be available from forest thinning.

Another potential source of forest material for biofuel production that the study discussed is a portion of the estimated 35.4 million tons of fuel wood used to heat homes and to provide heat for industries. The author cited a report which estimated that fuel wood use decreased from 1986 to 2000, but began to increase again and is expected to increase through 2050. This presumably means that if the demand for fuel wood is lower than previously, that some of that fuel wood could be available for producing biofuels. However, in this report, Marie Walsh did not make any firm estimate for this.

The Marie Walsh report also discussed that forest pulpwood supply is exceeding demand in the Southeast. The demand of forest pulpwood decreased from 131 to 121 million tons per year from 1993 to 2003, and this demand is expected to further decrease through 2020, and some have projected that this decrease in demand will continue beyond 2020. During the period between 1993 and 2003, pulpwood acreage and management intensity have increased, which suggests that the Southeast is and will continue to be over supplied. This oversupply of forest pulpwood could potentially provide additional biomass to the biofuels industry, although she did not provide any firm estimate for this nor an estimate of how much might qualify under RFS2.

It is important to note that not all of the forest biomass in the US Cellulosic Biomass Study would be eligible to be used as a biofuel feedstock under the RFS2 program. Despite this limitation, like the Billion Ton Study, this study is an important source of information, especially when considering the maximum amount of sustainably removable forest biomass.

While both of these studies provide quality assessments for the total amount of forest residue available for producing biomass, they both have an important limitation as well. The limitation is that these reports did not assess whether the forest residue in any particular area, along with other potential biomass, is of sufficient density to adequately supply a potential cellulosic biofuel plant. This feedstock density assessment must also consider the feedstock availability requirements made by cellulosic plant investors or banks, which may choose to require that a certain excess amount of feedstock be available to justify the use of that biomass in a cellulosic ethanol plant. Without considering these limitations, these studies may overestimate the quantity of biomass that would be truly usable and also the ultimate amount of biofuel that could be produced. Some of these issues were addressed in our cellulosic plant siting analysis in Section 1.8. Also, a study by the Western Governor's Association, which was designed to account for local biomass density, assessed the quantity of forest and other biomass that could be used for producing biofuels.[88] Because this study was only conducted for the Western United States instead of the entire country, we did not summarize it here. However, the study is being expanded nationwide and once completed it will provide nationwide results based on this very robust, bottom-up approach.

*U.S. Forest Service Data*

To assess forest residue supply within the feedstock density and supply constraints, we obtained county-by-county forest residue data from the U.S. Forest Service.[89] The information was provided by the subcategories of logging residue, primary mill residue, timberland thinnings, and other removals. The information also included urban forest residue, however, because that material is included with the other MSW, we did not consider it here (discussed later in Section 1.1.2.4). Like the studies discussed above, the national forest lands are omitted from consideration, and the urban forest residue is not considered here, but in the section discussing MSW. Most, if not all, of this material, therefore, would be eligible to be used as a feedstock for the production of biofuels under the RFS2 program, with the possible exception of some of the unused mill residues. The information was also provided at different price points. The quantities of forest residues are summarized by source type in Tables 1.1-15, 1.1-16 and 1.1-17. To avoid presenting a large amount of data, we aggregated the county data by state, and we are presenting the data at specific price points: $30/dry ton, $45/dry ton and $70/dry ton.

### Table 1.1-15.
### Volume of Forest Residue Available for Producing Biofuel
### Biomass Available at $30/ton

| | Logging Residue | Other Removals | Timerland Thinnings | Unused Mill Residue | Total Quantity |
|---|---|---|---|---|---|
| Alabama | 1,202,541 | 253,620 | 433,519 | 7,117 | 1,896,798 |
| Arizona | 8,849 | 22,436 | 33,085 | 1,351 | 65,721 |
| Arkansas | 851,772 | 385,492 | 369,083 | 12,889 | 1,619,236 |
| California | 334,870 | 0 | 871,351 | 65,088 | 1,271,309 |
| Colorado | 9,203 | 7 | 0 | 2,302 | 11,511 |
| Connecticut | 4,195 | 15,339 | 10,465 | 3,949 | 33,949 |
| Delaware | 15,051 | 12,109 | 4,918 | 0 | 32,077 |
| Florida | 535,215 | 257,704 | 240,947 | 2,202 | 1,036,067 |
| Georgia | 1,556,954 | 496,631 | 553,627 | 45,138 | 2,652,350 |
| Idaho | 126,573 | 0 | 41,548 | 6,006 | 174,126 |
| Illinois | 139,101 | 117,589 | 115,431 | 18,523 | 390,644 |
| Indiana | 281,242 | 52,087 | 198,112 | 10,627 | 542,068 |
| Iowa | 56,049 | 27,580 | 48,991 | 159 | 132,780 |
| Kansas | 7,329 | 44,202 | 9,676 | 8,720 | 69,928 |
| Kentucky | 513,989 | 332,179 | 344,948 | 55,196 | 1,246,311 |
| Louisiana | 1,317,139 | 440,293 | 300,924 | 30,075 | 2,088,431 |
| Maine | 1,206,438 | 470 | 80,314 | 42,483 | 1,329,705 |
| Maryland | 90,722 | 415 | 40,994 | 17,067 | 149,197 |
| Massachusetts | 35,461 | 31,043 | 13,801 | 0 | 80,305 |
| Michigan | 379,463 | 122,476 | 327,640 | 13,763 | 843,343 |
| Minnesota | 348,807 | 331,492 | 132,712 | 26,878 | 839,889 |
| Mississippi | 1,548,534 | 355,071 | 425,344 | 95,138 | 2,424,088 |
| Missouri | 387,434 | 265,146 | 342,077 | 79,787 | 1,074,443 |
| Montana | 131,335 | 0 | 66,592 | 9,136 | 207,063 |
| Nebraska | 10,572 | 9,386 | 11,707 | 4,971 | 36,637 |
| Nevada | 15 | 53 | 0 | 0 | 67 |
| New Hampshire | 157,321 | 174 | 47,802 | 7,019 | 212,316 |
| New Jersey | 2,959 | 39 | 2,288 | 1,437 | 6,723 |
| New Mexico | 11,929 | 1,279 | 25,898 | 4,902 | 44,008 |
| New York | 367,003 | 54,671 | 163,336 | 27,390 | 612,400 |
| North Carolina | 1,013,165 | 629,632 | 560,814 | 12,811 | 2,216,422 |
| North Dakota | 1,453 | 7,601 | 3,822 | 265 | 13,141 |
| Ohio | 185,398 | 9,053 | 83,676 | 22,600 | 300,726 |
| Oklahoma | 173,869 | 98,794 | 53,043 | 495 | 326,200 |
| Oregon | 760,276 | 31 | 527,702 | 16,316 | 1,304,326 |
| Pennsylvania | 543,663 | 699 | 224,978 | 170,972 | 940,312 |
| Rhode Island | 884 | 22,860 | 2,800 | 389 | 26,934 |
| South Carolina | 714,551 | 348,289 | 301,850 | 1,051 | 1,365,741 |
| South Dakota | 6,972 | 14,436 | 2,993 | 2,294 | 26,695 |
| Tennessee | 316,706 | 244,920 | 423,906 | 187,583 | 1,173,115 |
| Texas | 616,777 | 218,464 | 185,718 | 3,021 | 1,023,979 |
| Utah | 2,973 | 7 | 9,909 | 4,437 | 17,325 |
| Vermont | 104,876 | 18,652 | 48,395 | 0 | 171,923 |
| Virginia | 741,673 | 406,800 | 436,870 | 39,366 | 1,624,709 |
| Washington | 641,144 | 22 | 925,479 | 21,446 | 1,588,091 |
| West Virginia | 488,356 | 24,714 | 161,653 | 118,779 | 793,502 |
| Wisconsin | 568,800 | 491,132 | 260,293 | 60,410 | 1,380,636 |
| Wyoming | 11,343 | 0 | 14,050 | 34,014 | 59,407 |
| Total | 18,530,943 | 6,165,088 | 9,485,083 | 1,295,560 | 35,476,674 |

## Table 1.1-16.
## Tons of Forest Residue Available for Producing Biofuel
### Biomass Available at $45/ton

| | Logging Residue | Other Removals | Timerland Thinnings | Unused Mill Residue | Total Quantity |
|---|---|---|---|---|---|
| Alabama | 1,202,541 | 253,620 | 506,045 | 7,117 | 1,969,324 |
| Arizona | 13,566 | 21,210 | 34,967 | 1,351 | 71,094 |
| Arkansas | 851,772 | 385,492 | 429,414 | 12,889 | 1,679,567 |
| California | 583,478 | 0 | 949,468 | 65,088 | 1,598,034 |
| Colorado | 10,056 | 11 | 30,619 | 2,302 | 42,988 |
| Connecticut | 4,301 | 16,095 | 10,465 | 3,949 | 34,810 |
| Delaware | 17,932 | 14,145 | 6,700 | 0 | 38,777 |
| Florida | 535,215 | 257,704 | 266,597 | 2,202 | 1,061,718 |
| Georgia | 1,556,954 | 496,631 | 644,295 | 45,138 | 2,743,018 |
| Idaho | 216,303 | 0 | 52,594 | 6,006 | 274,902 |
| Illinois | 139,153 | 117,589 | 115,431 | 18,523 | 390,696 |
| Indiana | 281,464 | 52,087 | 221,845 | 10,627 | 566,023 |
| Iowa | 56,050 | 27,607 | 49,551 | 159 | 133,367 |
| Kansas | 7,329 | 44,202 | 9,676 | 8,720 | 69,928 |
| Kentucky | 513,989 | 332,179 | 407,371 | 55,196 | 1,308,735 |
| Louisiana | 1,317,139 | 440,293 | 330,512 | 30,075 | 2,118,019 |
| Maine | 1,280,511 | 495 | 102,442 | 42,483 | 1,425,931 |
| Maryland | 94,579 | 421 | 40,994 | 17,067 | 153,060 |
| Massachusetts | 39,127 | 33,191 | 13,801 | 0 | 86,119 |
| Michigan | 391,732 | 128,600 | 410,302 | 13,763 | 944,398 |
| Minnesota | 358,518 | 341,894 | 159,990 | 26,878 | 887,280 |
| Mississippi | 1,548,534 | 355,071 | 467,935 | 95,138 | 2,466,679 |
| Missouri | 387,434 | 265,146 | 466,082 | 79,787 | 1,198,448 |
| Montana | 215,597 | 0 | 70,775 | 9,136 | 295,507 |
| Nebraska | 10,710 | 9,434 | 11,707 | 4,971 | 36,822 |
| Nevada | 22 | 71 | 0 | 0 | 93 |
| New Hampshire | 165,519 | 197 | 57,566 | 7,019 | 230,301 |
| New Jersey | 3,184 | 40 | 2,423 | 1,437 | 7,084 |
| New Mexico | 17,239 | 1,287 | 26,862 | 4,902 | 50,291 |
| New York | 384,457 | 56,552 | 189,696 | 27,390 | 658,094 |
| North Carolina | 1,013,165 | 629,632 | 668,420 | 12,811 | 2,324,028 |
| North Dakota | 1,454 | 7,601 | 3,822 | 265 | 13,142 |
| Ohio | 186,022 | 9,069 | 88,572 | 22,600 | 306,263 |
| Oklahoma | 173,869 | 98,794 | 62,700 | 495 | 335,858 |
| Oregon | 1,341,835 | 34 | 574,948 | 16,316 | 1,933,133 |
| Pennsylvania | 1,341,835 | 34 | 574,948 | 170,972 | 2,087,789 |
| Rhode Island | 957 | 25,039 | 2,800 | 389 | 29,185 |
| South Carolina | 714,551 | 348,289 | 352,018 | 1,051 | 1,415,909 |
| South Dakota | 11,872 | 15,581 | 3,253 | 2,294 | 32,999 |
| Tennessee | 316,706 | 244,920 | 507,698 | 187,583 | 1,256,906 |
| Texas | 616,777 | 218,464 | 219,187 | 3,021 | 1,057,448 |
| Utah | 3,758 | 0 | 10,786 | 4,437 | 18,980 |
| Vermont | 108,542 | 19,182 | 53,836 | 0 | 181,560 |
| Virginia | 741,673 | 406,800 | 524,372 | 39,366 | 1,712,212 |
| Washington | 1,067,587 | 23 | 981,839 | 21,446 | 2,070,895 |
| West Virginia | 488,356 | 24,714 | 241,184 | 118,779 | 873,033 |
| Wisconsin | 576,938 | 499,302 | 327,027 | 60,410 | 1,463,677 |
| Wyoming | 18,163 | 0 | 18,202 | 34,014 | 70,380 |
| Total | 20,928,463 | 6,198,742 | 11,301,737 | 1,295,560 | 39,724,502 |

## Table 1.1-17.
## Tons of Forest Residue Available for Producing Biofuels
## Biomass available at $70/ton

| | Logging Residue | Other Removals | Timerland Thinnings | Unused Mill Residue | Total Quantity |
|---|---|---|---|---|---|
| Alabama | 1,202,541 | 253,620 | 581,654 | 7,117 | 2,044,933 |
| Arizona | 13,566 | 24,510 | 38,678 | 1,351 | 78,105 |
| Arkansas | 851,772 | 385,492 | 492,094 | 12,889 | 1,742,247 |
| California | 583,478 | 0 | 1,000,615 | 65,088 | 1,649,181 |
| Colorado | 10,056 | 11 | 30,619 | 2,302 | 42,988 |
| Connecticut | 4,301 | 16,095 | 10,465 | 3,949 | 34,810 |
| Delaware | 17,932 | 14,145 | 6,700 | 0 | 38,777 |
| Florida | 535,215 | 257,704 | 332,353 | 2,202 | 1,127,474 |
| Georgia | 1,556,954 | 496,631 | 776,911 | 45,138 | 2,875,634 |
| Idaho | 216,303 | 0 | 61,926 | 6,006 | 284,235 |
| Illinois | 139,153 | 117,589 | 115,431 | 18,523 | 390,696 |
| Indiana | 281,464 | 52,087 | 221,845 | 10,627 | 566,023 |
| Iowa | 56,050 | 27,607 | 49,551 | 159 | 133,367 |
| Kansas | 7,329 | 44,202 | 9,676 | 8,720 | 69,928 |
| Kentucky | 513,989 | 332,179 | 463,904 | 55,196 | 1,365,268 |
| Louisiana | 1,317,139 | 440,293 | 375,052 | 30,075 | 2,162,559 |
| Maine | 1,280,511 | 495 | 166,117 | 42,483 | 1,489,605 |
| Maryland | 94,579 | 421 | 40,994 | 17,067 | 153,060 |
| Massachusetts | 39,127 | 33,191 | 13,801 | 0 | 86,119 |
| Michigan | 391,732 | 128,600 | 533,107 | 13,763 | 1,067,203 |
| Minnesota | 358,518 | 341,894 | 200,599 | 26,878 | 927,889 |
| Mississippi | 1,548,534 | 355,071 | 516,598 | 95,138 | 2,515,342 |
| Missouri | 387,434 | 265,146 | 643,929 | 79,787 | 1,376,295 |
| Montana | 215,597 | 0 | 83,023 | 9,136 | 307,755 |
| Nebraska | 10,710 | 9,434 | 11,707 | 4,971 | 36,822 |
| Nevada | 22 | 71 | 0 | 0 | 93 |
| New Hampshire | 165,519 | 197 | 58,098 | 7,019 | 230,833 |
| New Jersey | 3,184 | 40 | 2,423 | 1,437 | 7,084 |
| New Mexico | 17,239 | 1,287 | 32,187 | 4,902 | 55,616 |
| New York | 384,457 | 56,552 | 192,851 | 27,390 | 661,249 |
| North Carolina | 1,013,165 | 629,632 | 800,455 | 12,811 | 2,456,063 |
| North Dakota | 1,454 | 7,601 | 3,822 | 265 | 13,142 |
| Ohio | 186,022 | 9,069 | 88,572 | 22,600 | 306,263 |
| Oklahoma | 173,869 | 98,794 | 81,634 | 495 | 354,792 |
| Oregon | 1,251,094 | 34 | 566,594 | 16,316 | 1,834,037 |
| Pennsylvania | 546,418 | 707 | 340,497 | 170,972 | 1,058,594 |
| Rhode Island | 957 | 25,039 | 2,800 | 389 | 29,185 |
| South Carolina | 714,551 | 348,289 | 395,555 | 1,051 | 1,459,446 |
| South Dakota | 11,872 | 15,581 | 4,129 | 2,294 | 33,875 |
| Tennessee | 316,706 | 244,920 | 516,550 | 187,583 | 1,265,759 |
| Texas | 616,777 | 218,464 | 253,670 | 3,021 | 1,091,931 |
| Utah | 3,758 | 7 | 14,717 | 4,437 | 22,918 |
| Vermont | 108,542 | 19,182 | 71,105 | 0 | 198,829 |
| Virginia | 741,673 | 406,800 | 630,366 | 39,366 | 1,818,206 |
| Washington | 1,067,587 | 23 | 1,029,985 | 21,446 | 2,119,041 |
| West Virginia | 488,356 | 24,714 | 287,639 | 118,779 | 919,489 |
| Wisconsin | 576,938 | 499,302 | 420,775 | 60,410 | 1,557,425 |
| Wyoming | 18,163 | 0 | 21,598 | 34,014 | 73,775 |
| Total | 20,042,304 | 6,202,722 | 12,593,373 | 1,295,560 | 40,133,959 |

The U.S. Forest Service data reveals that there are large amounts of forest material in the Southeast, the far Northeast and the Northwest portions of the U.S. The data also shows that the price curve for this forest material is fairly flat over the range summarized here. This suggests that the forests which are already accessible by roads provide access to low cost forest material from the thinning of timberland. However, to access more and more of the timberland, the costs ramp up quickly. These numbers are also significantly different than those presented in the proposed rule. This is due to a misunderstanding in how the number should be interpreted. According to our contacts at the U.S. Forest Service whether logging residue or timberland thinnings would be available would depend on the type of logging operation being used. We cannot, therefore, assume that 100% of the logging residue and timberland thinnings would be available, as this would be double counting the potential for wood residues. Instead, we must assume that a certain percentage of logging operations would produce logging residue and that the rest would produce timberland thinnings. Based on suggestions from the U.S. Forest Service we have assumed that 50% of logging operations would produce logging residue and 50% would produce forestry thinnings. Additionally, the U.S. Forest Service data includes unused mill residue, which may not be qualifying biofuel feedstock under RFS2 depending on the source of the wood. While these changes result in a significant decrease in the amount of wood residue available from current forestry operations they have no impact on our analyses. This is due to the fact that the amount of wood residues used in cellulosic biofuel production, as projected by the FASOM model, is still far less than the total available wood residue.

It is also important to note that this data is based solely on current forestry operations. It represents the amount of wood residue that would be available today if these residues were recovered. The United States contains much forest land that is not currently in active production due to insufficient demand and low prices for forestry products. If demand for cellulosic feedstock sufficiently increased the demand for forestry products it is very possible that logging operations would expand to meet this need. In this sense, the data from the U.S. Forest service is not an evaluation of the maximum amount of forestry residue that could be sustainable removed, but rather a measure of how much residue could be recovered based on current logging operations. Logging operations are financed based on their higher value products (i.e., lumber), not based on demand for lower value products (i.e., residues), so it is unlikely investments would be made to harvest forest residues absent demand for lumber operations. Nevertheless, this data is valuable, as the value for cellulosic biomass would likely have to be significantly higher than we are projecting in order to drive logging operation expansion.

### *Forestry Sector Modeling in FASOM*

In addition to the agriculture sector, the FASOM model also contains a forestry component, which details forest acres across the U.S. as well as production of forestry products. Running the forestry and agriculture components of the model simultaneously shows the interaction between these two sectors as they compete for land, as well as the effect on products and prices in each respective sector. In total, FASOM includes a representation of seven major land use categories, including cropland, cropland pasture, forestland, forest pasture, rangeland, developed land, and acres enrolled in the Conservation Reserve Program (CRP). More information on these land categories can be found in Chapter 5.1.2.

Various products from the forestry sector in the FASOM model can be used to produce cellulosic renewable fuel. These products include hardwood and softwood milling, and logging residues. The FASOM model projected that 110 million gallons from forestry logging would be used to meet the cellulosic biofuel standard under EISA.

*Wood Summary*

We compared the quantity of potential biomass supplies projected to be available in 2022 by the two studies and the data that the Forest Service provided us in Table 1.1-18.

**Table 1.1-18.**
**Forest Biomass Availability in 2022 at Different Prices (million dry tons)**

| | **Price ($/ton)** | | |
|---|---|---|---|
| | **30** | **45** | **70** |
| Billion Ton Study | 79 | | |
| U.S. Cellulosic Biomass Study | 20 | 103 | 118 |
| Forest Service Data | 35 | 40 | 40 |

For the rule we were able to incorporate the forestry sector model in FASOM which projected 110 million gallons of forestry biomass would be used to meet the cellulosic biofuel standard. This would require close to 1 million dry tons per year of forestry biomass. As noted by the studies and data from the U.S. Forest Service, this amount is a small fraction of the large amount of forestry biomass potentially available. Although there is additional forestry biomass available for cellulosic renewable fuel production, other sources of cellulosic renewable fuel (switchgrass and corn residue, in particular) are relatively more profitable for producers of cellulosic renewable fuel feedstocks. For details on the economic impacts of the RFS2 program, including prices of cellulosic feedstocks as modeled in FASOM, see Chapter 5.

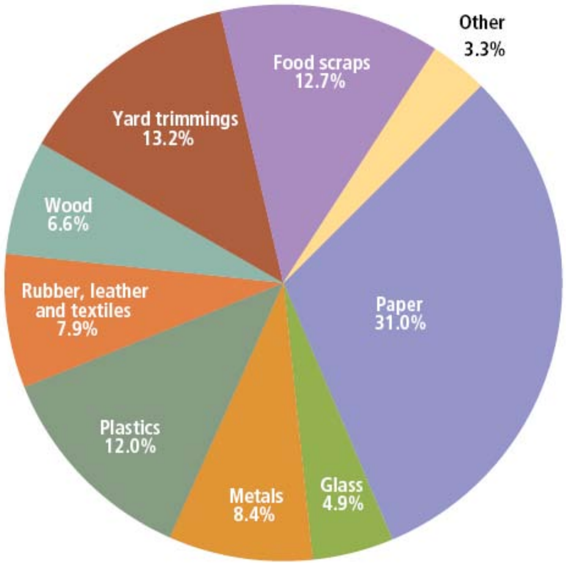
### 1.1.2.4 Urban wastes

Cellulosic feedstocks available at the lowest cost to the ethanol producer will likely be chosen first. This suggests that urban waste which is already being gathered today and typically incurs a fee for its disposal may be among the first to be used. Urban wastes are used today in a variety of ways. Most commonly, wastes are ground into mulch, dumped into land-fills, or incinerated. Estimating the amount of urban waste available for biofuel production involves understanding the types of materials that can be found in urban waste, potential competing uses of urban waste, and the challenges with separating a mixed feedstock.

*Municipal Solid Waste*

MSW consists of paper, glass, metals, plastics, wood, yard trimmings, food scraps, rubber, leather, textiles, etc. See Figure 1.1-4 for the percent composition of MSW generated (before recycling) in 2008.[90] Construction and demolition debris is not included in the estimate and is discussed separately below.

**Figure 1.1-4.**
**Total MSW Generation (by Material), 2008**
**250 Million Tons (Before Recycling).**



The portion of MSW that can qualify as renewable biomass under the program is already discussed in the preamble, Section II.B.4.d. The bulk of the biogenic portion of MSW that can be converted into biofuel is cellulosic material such as wood, yard trimmings, paper, and much of food wastes. Paper made up the majority of the total MSW generated in 2008, approximately 31 percent.

Although recycling/recovery rates are increasing over time, there appears to still be a large fraction of biogenic material that ends up unused and in land-fills. In order to project the portion of material that can potentially be used for biofuel purposes, we must understand how the composition of landfilled material changes over time. To do this, we first analyzed the trends from 2000-2007 for the percent composition of total MSW generated from paper/paperboard, wood, and yard trimmings over time as shown in Table 1.1-19 in order to project the percent composition of total MSW generated for the year 2022 for those categories (i.e. calculated to be 24.5% paper, 5.6% wood, and 12.8% yard trimmings and 15.1% food scraps).[91] In general, there appears to be a decrease in the percentage of total MSW generated from paper, slight increase for food scraps, and a relatively stable percent composition of wood and yard trimmings.

### Table 1.1-19. Percent Composition of Total MSW Generated (including recyclable material): Paper, Wood, and Yard Trimmings

| | 2000 | 2004 | 2005 | 2006 | 2007 | … | 2022 |
|---|---|---|---|---|---|---|---|
| Material | | | | | | | |
| Paper/paperboard | 36.7 | 34.6 | 33.9 | 33.6 | 32.7 | … | 24.5 |
| Wood | 5.5 | 5.6 | 5.6 | 5.5 | 5.6 | … | 5.6 |
| Yard Trimmings | 12.8 | 12.7 | 12.8 | 12.7 | 12.8 | … | 12.8 |
| Food Scraps | 11.2 | 11.8 | 12.1 | 12.2 | 12.5 | … | 15.1 |

We also analyzed the trends from 2000-2007 for the percent composition of total MSW discarded (i.e. after recycling has occurred) to project the percent compositions for the year 2022 (i.e. calculated to be 8% paper, 8% wood, 3% yard trimmings, and 21.5% food scraps), see Table 1.1-20 and Table 1.1-21. Comparing Table 1.1-19 and Table 1.1-20, we note that historically there is a lower percent of paper and yard trimmings that is discarded than generated for MSW. This makes sense because a large percentage of these materials are recycled. Other than recycling, some MSW material is also combusted for energy use. This material we assume would be unavailable for biofuel use, and therefore report in Table 1.1-21 the percent composition of total MSW discarded after accounting for both recycling and combustion for energy use.

### Table 1.1-20. Percent Composition of Total MSW Discarded (not including recycled material): Paper, Wood, and Yard Trimmings

| | 2000 | 2004 | 2005 | 2006 | 2007 |
|---|---|---|---|---|---|
| Material | | | | | |
| Paper/paperboard | 29.6 | 26.6 | 25.1 | 24.1 | 22.3 |
| Wood | 7.0 | 7.3 | 7.5 | 7.4 | 7.6 |
| Yard Trimmings | 8.7 | 7.0 | 7.1 | 7.2 | 6.9 |
| Food Scraps | 15.4 | 16.7 | 17.3 | 17.6 | 18.2 |

### Table 1.1-21. Percent Composition of Total MSW Discarded (not including recycled or combusted material): Paper, Wood, and Yard Trimmings

| | 2000 | 2004 | 2005 | 2006 | 2007 | … | 2022 |
|---|---|---|---|---|---|---|---|
| Material | | | | | | | |
| Paper/paperboard | 25.4 | 23.2 | 21.9 | 21.1 | 19.5 | … | 8.0 |
| Wood | 6.0 | 6.4 | 6.6 | 6.5 | 6.6 | … | 8.0 |
| Yard Trimmings | 7.5 | 6.1 | 6.2 | 6.3 | 6.0 | … | 3.0 |
| Food Scraps | 13.2 | 14.6 | 15.1 | 15.4 | 15.9 | | 21.5 |

The total amount of MSW generated (prior to recycling) is assumed to increase over time due to population growth. Biocycle magazine (2008) reports MSW estimates for each state in the U.S. based off of 2006 population data.[92] We used U.S. Census Bureau population projections by state to scale up or down the MSW estimates depending on whether the state populations increase or decrease by 2022. The total amount of MSW generated (prior to recycling) was estimated to be 415 million tons in 2022. As we are interested in the volume of MSW available for biofuel use, we focused only on waste estimated to be landfilled, which is a portion of the total MSW generated. We used estimates on the percentage of MSW landfilled by state from Biocycle in order to estimate the amount of MSW potentially available to biofuels (after recycling).

Knowing the total amount of MSW landfilled is only part of the picture. We also need to understand the types of cellulosic material likely to make up the MSW landfilled. For this, we were able to gather state composition data (i.e. percent wood vs. paper vs. other materials) of landfills for MSW *generated*, however, we were in fact interested in acquiring state composition data for the MSW *landfilled*.[93,94,95,96,97,98,99,100,101,102,103] Using the state composition data, we estimated the percent composition of MSW landfilled by state using a ratio of percent composition of national material generated (estimated in Table 1.1-19) and landfilled (estimated in Table 1.1-21) and state percent composition data for MSW generated (gathered from the multiple state reports). We then multiplied the volume of MSW (in tons) generated for each state in the year 2022 by the percent of MSW estimated to be landfilled (provided in Biocycle) and by the percent composition of MSW landfilled by state. Some states did not provide composition data, therefore, we estimated average percentages based on the states within a similar location in the U.S. where data was provided (e.g. if Utah data was unavailable, we assumed compositions would be similar to other rocky mountain states).

Furthermore, the amount of MSW potentially available is limited by assumptions on percent moisture and percent contamination. We assumed that paper, wood, yard trimmings, and food scraps have a 10%, 20%, 40%, and 70% moisture content, respectively.[104,105] We also assumed that wood is approximately 50% contaminated, due to objects such as nails, paint, chemicals, etc. typically associated with such feedstocks.[106] Paper and food wastes are assumed to be mostly uncontaminated, assuming 95% uncontaminated.[107] Yard trimmings are also assumed to be largely uncontaminated, assuming 75% uncontaminated. We account for contamination because it is likely to affect the quality of the wood waste and could potentially cause problems in the processing steps of cellulosic material to biofuel depending on the process utilized. Thus, for this analysis we conservatively assumed that the estimated contaminated portions would not be used for biofuel production. In addition, not all yard trimming can be assumed to be wood, 90% is assumed to be from wood.[108] We also estimated the amount of food waste that is cellulosic material to be 45%.[109] We estimate that 23.8 million dry tons could be available after accounting for these factors from paper, 0.9 million dry tons from yard trimmings, 5.3 million dry tons from wood, and 6.5 million dry tons from food waste.

### *Construction and Demolition (C&D) Debris*

C&D debris mostly comes from building demolition and renovation, and the rest comes from new construction. Roughly equal percentages of building-related waste are estimated to come from the residential and commercial building sectors. The composition of C&D materials varies significantly, depending on the type of project from which it is being generated. For example, materials from older buildings is likely to contain plaster and lead piping, while new construction materials may contain significant amounts of drywall, laminates, and plastics. For building materials, EPA estimates the overall percentage of debris in C&D materials falls within the following ranges:

**Table 1.1-22.**[110]
**Percentage Composition of C&D Debris**
**(by volume)**

| | |
|---|---|
| Concrete and mixed rubble | 40-50% |
| Wood | 20-30% |
| Drywall | 5-15% |
| Asphalt roofing | 1-10% |
| Metals | 1-5% |
| Bricks | 1-5% |
| Plastics | 1-5% |

In 1996, total C&D debris generated was estimated to be approximately 124 million metric tons.[111] As seen in Table 1.1-22 above, only a portion of this, however, would be made of woody material. We based our estimate of C&D wood in 2022 on the equation adopted from Wiltsee's analysis.[112] The equation estimated C&D wood based on population size. We estimated approximately 31 million tons could be available from this resource by 2022; however, we assumed that 50% of that could potentially be contaminated and a portion of the feedstock would likely already be recovered. Thus, we estimate that only 8 million dry tons would be available for biofuels.

*Urban waste summary*

After estimating the total amount of urban waste available as described in the sections above, we further estimated the potential locations that could utilize this material. This is described in more detail in Section 1.8.1.3, the cellulosic ethanol plant siting analysis. From this analysis we determined that of the 44.5 million dry tons of MSW and C&D wood waste available, approximately 26 million dry tons would be used to produce 2.3 ethanol-equivalent billion gallons of fuel.[J] We estimated urban wastes outside our agricultural modeling as the models do not focus on such feedstocks. The other portion of the 16 billion gallons of cellulosic biofuel standard (13.7 billion gallons) was split among the other feedstock types, namely agricultural residues, forestry biomass, and energy crops, depending on the economic competitiveness. Refer to Chapter 5 more details on the FASOM and FAPRI-CARD modeling.

### 1.1.2.5 Imported Cellulosic Feedstocks or Biofuels

Cellulosic biofuel could also be produced internationally. One example of internationally produced cellulosic biofuel is ethanol produced from bagasse from sugarcane processing in Brazil. Currently, Brazil burns bagasse to produce steam and generate bioelectricity. However, improving efficiencies over the coming decade as well as mechanization of sugarcane harvesting (no burning of biomass in fields) may allow an increasing portion of bagasse to be allocated to other uses, including cellulosic biofuel, as additional straw could potentially be collected and used to produce bioelectricity.

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[J] Assuming 90 gal/dry ton ethanol conversion yield for urban waste in 2022

In fact, a recent study was performed under the Memorandum of Understanding to advance collaboration in biofuels, signed by Brazil and the United States on March 2007.[113] The key objective of the work was to compare the techno-economic performance for thermochemical and biochemical conversion of sugarcane residues to ethanol. Studies such as this one help identify the anticipated costs and challenges with utilizing cellulosic feedstocks for biofuels.

Another study assessed the biomass feedstock potential for selected countries outside the United States and projected supply available for export or for biofuel production.[K,114] For the study's baseline projection in 2017, it was estimated that approximately 21 billion ethanol-equivalent gallons could be produced from cellulosic feedstocks at $36/dry tonne or less. The majority (~80%) projected is from bagasse, with the rest from forest products. Brazil was projected to have the most potential for cellulosic feedstock production from both bagasse and forest products. Other countries including India, China, and those belonging to the Caribbean Basin Initiative (CBI) also have some potential although much smaller feedstock supplies are projected as compared to Brazil.

### 1.1.2.6 Cellulosic Feedstock Summary

Table 1.1-23 summarizes our internal estimate of the types of cellulosic feedstocks projected to be used and their corresponding volume contribution to 16 billion gallons cellulosic biofuel by 2022 for the purposes of our impacts assessment. Refer to previous sections for more details on how the values in this summary table were derived. The majority of feedstock is projected to come from dedicated energy crops, with smaller volumes from agricultural residues, forestry biomass, and urban waste.

**Table 1.1-23.**
**Cellulosic Feedstocks Assumed To Meet EISA In 2022[L]**

| **Feedstock** | **Volume (Ethanol-equivalent Bgal)** |
|---|---|
| Agricultural Residues | 5.7 |
| Corn Stover | 4.9 |
| Sugarcane Bagasse | 0.6 |
| Wheat Residue | 0.1 |
| Sweet Sorghum Pulp | 0.1 |
| Forestry Biomass | 0.1 |
| Urban Waste | 2.3 |
| Dedicated Energy Crops (Switchgrass) | 7.9 |
| Total | 16.0 |

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[K] Countries evaluated include Argentina, Brazil, Canada, China, Colombia, India, Mexico, and CBI

[L] Volumes are represented here as ethanol-equivalent volumes, a mix of diesel and ethanol volumes.

### 1.1.3 Biodiesel & Renewable Diesel Feedstocks

In general, plant and animal oils are valuable commodities with many uses other than transportation fuel. Therefore we expect the primary limiting factor in the supply of both biodiesel and renewable diesel to be feedstock availability and price. Primary drivers for this are increasing worldwide demand for use as food as incomes rise in developing countries, as well as increased recognition that these materials have value based on their energy or hydrocarbon content as substitutes for petroleum. Expansion of biodiesel market volumes beyond the mandates is dependent on it being able to compete on a price basis with the petroleum diesel being displaced.

The primary feedstock for domestic biodiesel production in the U.S. has historically been soybean oil, with other plant and animal fats and recycled greases making up a varying portion of the biodiesel pool as commodity prices rise and fall. For example, following a rise in soy oil prices and then a decline in diesel prices, the share of biodiesel being produced from rendered or reclaimed fats or other cheap feedstocks increased steeply in 2008 and 2009. [115] Another feedstock we project to become a significant and economical alternative over the next decade is corn oil produced during ethanol production (see 1.1.3.2 below).

#### 1.1.3.1 Virgin Plant Oils

Agricultural commodity modeling we have done for this proposal (see Chapter 5 of this document) suggests that soybean oil production will stay relatively flat in the future, meaning supplies will be tight and prices supported at a high level as biofuel and food-related demand increases. Modeling scenarios conducted for the year 2022 with the EISA mandates indicates that domestic soy oil production would support about 660 million gallons of biodiesel production. This material is most likely to be processed by biodiesel plants (as opposed to renewable diesel hydrotreating processes) due to the large available capacity of these facilities and their proximity to soybean production. Compared to other feedstocks, virgin plant oils are most easily processed into biofuel via simple transesterification due to their homogeneity of composition and lack of contaminates.

#### 1.1.3.2 Corn Oil Extracted During Ethanol Production

A source of feedstock which could provide significant volume is oil extracted from corn or its fermentation co-products in the dry mill ethanol production process. Often called corn fractionation, dry separation, or corn oil extraction, these are a collection of processes used to get additional product streams of value from the corn. This idea is not new, as existing wet mill plants create several streams of product from their corn input, including oil. In a dry mill setting, the kernel can be separated into the bran, starch, and germ components ahead of fermentation, or alternatively, oil can be extracted from the distillers' grains after fermentation. Both have advantages and disadvantages related to plant capital cost and energy consumption, as well as yield of ethanol and the other coproducts. For more information on these technologies, see Section 1.4.1.3.

Extraction of oil from the thin stillage or distillers' grains with solubles (DGS) streams is a proven technology that can be retrofitted into existing plants relatively cheaply. Front-end separation (fractionation) requires more intensive capital investment than is required to extract oil from the DGS, and therefore is best designed into the plant at the time of construction. However, it yields a larger array of co-products, and generally also results in ethanol process energy savings since less unfermentable material is going through the process train. The corn oil produced from the fractionation process is food grade corn oil and therefore has a significantly higher market value than the inedible corn oil produced by the oil extraction process. For our analyses for the final rule we have chosen to focus only on the oil produced by extraction, as we believe the higher value of the food grade corn oil makes it highly unlikely it will be used in biodiesel production.

Information on the expected oil extraction rates, capital costs, and energy use of corn oil extraction systems is based on conversations with several technology providers. Depending on the configuration, this system can extract 25-75 percent of the oil from the fermentation co-products, producing an oil stream which can be used as feedstock by biodiesel facilities. Since it offers another stream of revenue from the corn flowing into ethanol plants, we assumed approximately 70 percent of projected total ethanol production will implement some type of corn oil extraction system by 2022, generating approximately 680 million gallons per year of corn oil biofuel feedstock.[116,M] We expect this material to be processed in biodiesel plants with pretreatment capabilities for handling feedstocks with significant free fatty acid (FFA) content. At this time it is uncertain whether there will be third party aggregators of this extracted oil, or whether individual ethanol plants will contract directly with nearby biodiesel facilities, which may ultimately impact where and how this feedstock is processed.

### 1.1.3.3 Yellow Grease and Other Rendered Fats

Rendered animal fats and reclaimed cooking oils and greases are another potentially significant source of biodiesel feedstock. The National Renderer's Association gives a quantity of approximately 11 billion lbs of fats and greases available annually for all uses, and suggests this will grow by 1% per year.[117] This figure is broken down into several categories, and includes "yellow grease" and "other grease" collected and processed by rendering companies each year. The NRA defines yellow grease as material primarily derived from restaurant grease or cooking oil (they do not define "other grease" but we can assume this is trap grease or other reclaimed material). Adding together the NRA's "yellow grease" and "other grease" categories, we arrive at 2.7 billion lbs per year (all figures there are for 2005).

Similarly, a 2004 report prepared for New York State Energy Research and Development Authority by LECG, LLC describes yellow grease as material produced by restaurants and food service.[118] (This report describes grease recovered from sewer traps as brown grease, and suggests it is too low in quality to be used for biodiesel production.) Based on USDA and US Census data, LECG shows production of yellow grease by restaurants to be on the order of 9 lbs per capita per year, equivalent to about 2.7 billion lbs/yr. Unfortunately, it's not clear whether this quantity would include or be in addition to the NRA figures, but given the similarity of

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[M] The projected fraction of plants doing corn oil extraction was based on a conversation with several technology providers and various people working in the ethanol industry.

numbers, it seems reasonable to suspect that the NRA total includes the same sources of grease as assessed by LECG.

Thus, the figures we use here assume that the NRA figures already include collection of a large portion of restaurant and trap grease by rendering companies; we have not included additional waste greases that other studies have suggested might be available based on per-capita use of cooking oils, wastewater treatment disposal, etc. Perhaps there is some additional waste grease not being collected or counted by the NRA that is, or could be, aggregated and direct to biofuel production, but there is unfortunately no good way for us to determine this.

Our projections would use approximately 22% of this material for biofuel use in 2022 (= 380 million gallons x 7.5 lb/gal / 13 million lbs). In a written statement by David Meeker of the NRA, he asserts that it could be feasible for as much as 30% of the 11 billion lbs to be directed to biofuel production on a long-term basis.[119] The feasibility of consumption of this volume of rendered material was also supported by comments from a large rendering company (Darling International).

Much of biodiesel production seems to rely on niches of feedstock availability and market outlets. We project that approximately 230 MMgal/yr of rendered or reclaimed fats will be processed by biodiesel plants possessing acid pretreatment capabilities to handle these high-free fatty acid feedstocks. We project another 150 MMgal/yr of this material will be used by renewable diesel facilities. It is possible that renewable diesel manufacturers will arrange direct contract or joint venture with animal processing or rendering operations, taking advantage of volumes or prices of feedstock that may not typically be available on the open market to smaller, unaffiliated biodiesel plants.

Some comments submitted to the docket by Endicott Biofuels, LLC, suggest there are additional sources of waste greases and oils sufficient to produce an additional 2 or more billion gallons' worth of biofuel (beyond what we account for above) if they could be collected and processed. We have chosen to ignore these volumes in this analysis, as their use will likely require further pre-treatment and additional processing steps beyond the capabilities most of the installed biodiesel production capacity. However, it is conceivable that these materials may begin to be used in significant quantities as dictated by regulatory or economic conditions.

### 1.1.3.4 Algae

Algae are single-celled algae species that grow quickly and can be cultivated to produce biomass for the downstream production of fuel based on the oil and residuals found in the biomass. Many of these algae species are targeted for their high lipid content, and thus are a promising feedstock for biofuel production. While some algae companies are focusing on the use of algae for biodiesel production, it is important to note that algae can alternatively be used for producing ethanol or crude oil for gasoline or diesel which could also help contribute to the advanced biofuel mandate.[N] Some of the potential benefits of using algae as a biofuel feedstock are that algae can be grown on marginal land, can require low water inputs, can recycle waste streams from other processes, does not compete with food production, and has high oil yield.

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[N] Algenol and Sapphire Energy, see http://www.algenolbiofuels.com/ and http://www.sapphireenergy.com/

Mass cultivation of microalgae has been ongoing since the 1950s for medical and pharmaceutical purposes. Since the 1980s, algae-to-biofuel research has been heavily funded by governments such as Japan, France, Germany and the United States. The research program in the US was especially large. The Aquatic Species Program, backed by the National Renewable Energy Laboratory, ran from 1978-1996 to look at the use of aquatic plants, specifically algae, as sources of energy. From about 1982 through the termination of the program, research concentrated on algae for biofuel production, specifically in open ponds.[120] Two branches to research large scale algaculture systems were funded: the "High Rate Pond" and the "Algae Raceway Production System" from 1980 to 1987. By 1988 several large (1,000 $m^2$) systems were designed and built at the "Outdoor Test Facility."[121] However, overall productivity of the ponds was lower than expected at around 10 grams algae / $m^2$ / day, due to cold temperatures and native species of algae taking over the ponds. After the program ended the total amount of algae research was relatively small because of lack of funding and growing interest in cellulosic ethanol.[122] In the 1990s Japan's NEDO-RITE Optical Fiber Bioreactor project obtained support from several private companies, laboratories, and academic institutions. However, the program was unsuccessful due to high costs for producing algae. Most recently, universities and start-up companies have been conducting pilot studies on the cultivation and processing of algae. With the high price of oil in 2008 and increased interest from airline providers to cut costs, fuel companies and start-ups have begun collaboration efforts to develop alternative biofuels from algae.

For analyses purposes, we assumed that 100 million gallons of algae-based biodiesel would be available by 2022 to help meet the biomass-based diesel standard. We believe this is reasonable given several announcements from the algae industry about their production plans which is further described in Section 1.5.4.3.[O]

A recent report released in October 2009 entitled "Cultivating Clean Energy: The Promise of Algae Biofuels" is a good resource for understanding the basic pathways for algae-based biofuels and summarizes some of the areas that can be improved to further commercialization of algae-based biofuels.[123] We discuss some of the information contained in the report, below.

In addition, we have consulted with the National Renewable Energy Laboratory (NREL) on developing several reasonable pathway scenarios for algae producing oils for biodiesel.[124] While there are many different technologies and fuel combinations being considered for algae-based biofuels, we believe the analyses completed by NREL for the FRM are representative of what is possible for the algae industry by 2022. As time permits, we hope to evaluate different configurations and their impact on production parameters. To provide further understanding, the modeling completed by NREL also included sensitivity analyses which evaluated various parameters and their affect on the costs of production (e.g. nutrients required, $CO_2$ delivered,

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[O] Sapphire Energy plans for 135 MMgal by 2018 and 1 Bgal by 2025; Petrosun plans for 30 MMgal/yr facility in Arizona; Solazyme plans for 100 MMgal by 2012/13; US Biofuels plans for 4 MMgal by 2010, 50 MMgal by full scale. Only several companies have thus far revealed production plans, and more are announced each day. It is important to realize that future projections are highly uncertain, and we have taken into account the best information we could acquire at the time.

etc.). The following sections also summarize some of the assumptions and results from the NREL modeling for algae; see the technical document for more details. Also, refer to Chapter 2 for a discussion of how we used the modeling of algae pathways from NREL for our lifecycle analyses. For more information on the costs of production for algae from biodiesel, refer to Chapter 4.

### *Cultivation*

Algae require several inputs, including water, land, nutrients, and in most cases, light to sustain growth. The configuration of the algal system impacts the amount of these inputs needed. Microalgae, which can have a high mass percentage of triacylglycerols, or natural oils, can be cultivated typically using either of two methods.

One method that is currently in use, and was studied widely by the Aquatic Species Program, involves using large, open ponds to grow algae; generally considered the most efficient and low-cost option is the so- called "raceway" ponds, as their shape is similar to an oval racetrack. A paddle wheel is used to keep the water in motion around the pond. Other open pond systems include unstirred and circular ponds; however, these may have more limited use for large scale fuel production.

The other method of algae cultivation utilizes closed "photobioreactors" which can fall in two groups, flat plate and tubular. Flat plate PBRs are made up of a clear plastic containment system and tubular PBR's are clear tubes that carry a circulation of culture between degassing and harvesting. Tube PBRs are generally considered more feasible for large scale use since they are modular and can accommodate higher flows.[125] PBRs can also be placed indoor or outdoor. Indoor closed PBRs usually require artificial illumination. Outdoor closed PBRs use natural daylight and in some cases also artificial light. There are also variations on cultivation systems such as hybrid (combined open and closed) cultivation, heterotrophic cultivation (without light), and integrated biofixation systems.[P]

Due to higher cell densities, the use of photobioreactors typically has lower land use in comparison to open pond systems producing the same volume of fuel. While other oil crops may need large amounts of agricultural land in order to meet a sizable portion of US liquid fuel demand, algae may limit the amount of land needed due to its high productivity and do not require the displacement of agricultural crops. [126,127,128]

When cultivated in enclosed photobioreactors, evaporation of water is limited, and water extracted during the drying process can be mostly reclaimed.[129] Even in open raceway-style ponds where evaporation is not negligible, water requirements are still considerably lower than with conventional agricultural crops. It is estimated that, in order to produce enough algal biomass for 60 billion gallon biodiesel/year, 20-120 trillion gallons of water/year are needed. This is several orders of magnitude lower than the 4,000 trillion gallon/year used to irrigate the entire US corn crop.[130]

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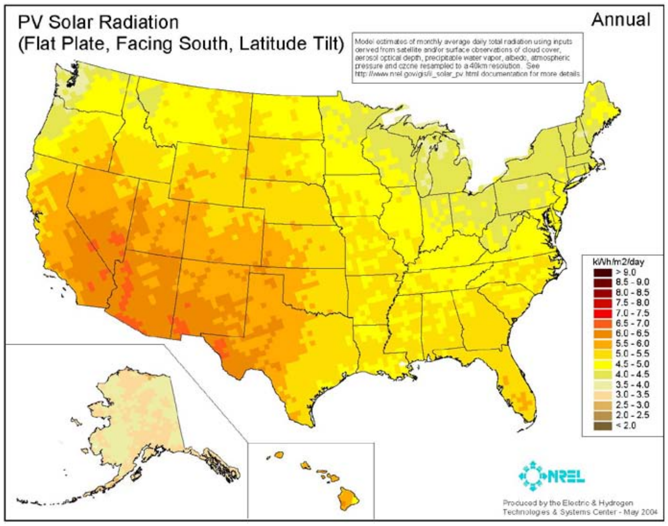
[P] For more information on these variations, refer to the recent report "Cultivating Clean Energy: The Promise of Algae Biofuels".

Algae can also thrive in brackish water, with salt concentrations up to twice that of seawater, which is often available in saline groundwater aquifers in the southwest.[131, 132] However, the salt, other minerals, and contaminants may pose a problem to the dewatering and extraction process, depending on the method used.

Aside from sunlight, land, and water, algae require two main physical inputs for growth: $CO_2$ and nutrients.[133] Nutrients can be obtained from conventional fertilizers, or from domestic or industrial waste sources, such as farm refuse and manure.[134] Co-locating algae farms with animal husbandry, in order to directly use the manure as a nutrient, would reduce transportation costs.[135] In addition, both of these inputs can be obtained from waste streams from other energy processes. They can be coupled with coal-burning power plants or even ethanol plants, and can effectively recycle between 50% and 90% of flue gasses, depending on the size of the algae farm.[136,137,138] The highly controlled environment of algae photobioreactors make them especially suitable to process and recycle $CO_2$ in flue gasses, as the gas can be bubbled or channeled into the water.[139]

The US southwest is perhaps one of the most promising locations for economic algae-for-biofuel cultivation, due to its high solar insolation (see Figure 1.1-5), availability of saltwater aquifers, and relatively low current land use.[140,141] Ideally, algae farms could be co-located with coal-burning power plants in order to recycle the carbon emissions. One study states that 1,700 power plants throughout the United States have enough surrounding land to support a commercial-scale algae system, however, only a limited number of these are in the southwest, due to lower population densities.[142]

**Figure 1.1-5.**
**PV Solar Radiation in the United States**



In terms of yields, certain species of algae can produce 80 percent of their body weight as oils, however, oil levels of 20-50 percent are more common.[143,144] Raceway systems are typically lower cost but have lower productivity compared to photobioreactors. The following Table 1.1-24 is based on the modeling of algae production from NREL and gives an idea of the yields that are reasonable under a base case (assumptions reasonable but still challenging in near future), aggressive case (assumes identification of a strain with near optimal growth rates and lipid content) and a max case (represents near theoretical maximum based on photosynthetic efficiencies).

**Table 1.1-24. Potential Algae Yield[Q] (gal/acre per year)**

| Base Case | | Aggressive Case | | Max Case | |
|---|---|---|---|---|---|
| op | PBR | op | PBR | op | PBR |
| 2108 | 5271 | 6748 | 16863 | 12151 | 30395 |

*Harvesting*

Harvesting is necessary to recover biomass from the cultivation system. Commonly used techniques include flocculation, dissolved air flotation (DAF), centrifugation, microfiltration, and decantation. Additional techniques include discrete sedimentation, membrane filtration, phototactic autoconcentration, tilapia-enhanced sedimentation, tube settling, and ultrasonic separation. Wet biomass may also be dewatered or dried. Dewatering decreases the moisture content by draining or mechanical means. Additional drying can follow using e.g. drum dryer, freeze dryer, spray dryer, rotary dryer, or by solar drying.

*Oil Extraction and Recovery*

Oil from algae can be extracted through chemical, mechanical, or electrical processes to separate the algal oil from the cell membrane. The TAGs (Triacylglycerides) are typically the main product which goes to biodiesel production. The remainder consists of carbohydrates, proteins, nutrients, and ash), usually referred to as algal residue.

The extraction step is commonly regarded as the most speculative in terms of large-scale feasibility.[145] Thus extraction is a critical area of research going forward to achieve practical algal lipid production. Some of the methods discussed are solvent extraction, supercritical fluid extraction, mechanical extraction, osmotic shock, and sonication.

The spent biomass (i.e. algal residue) can be used in anaerobic digestion and power generation via gas turbine which provides power to run the plant. The other method commonly discussed is its use as animal feed.

*Oil Conversion to Biofuel*

Algal oil can undergo transesterification to produce biodiesel or be hydroprocessed to renewable products (e.g. renewable diesel) depending on the slate of products desired. In some cases, the entire algae biomass is converted using thermochemical and biochemical methods such as pyrolysis, gasification, liquefaction, and fermentation to produce biofuels. See Figure 1.1-6 for the various pathways for the processing of algal biomass.

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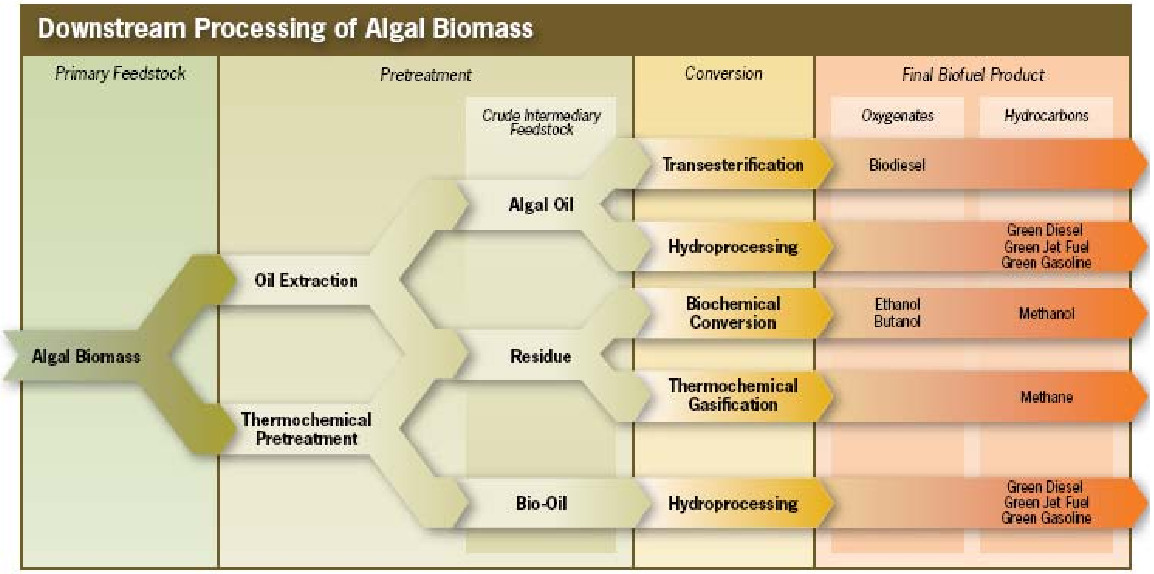
[Q] Only land required for pond/PBR, not including land necessary for processing equipment

**Figure 1.1-6. Pathways for Processing Algal Biomass**[146]



### 1.1.3.5 Other Potential Feedstocks

The following sections describe several oil crops that have also been discussed as potential biofuel feedstocks. While we have not projected the use of these crops in our current impact analyses, these may still be used to help meet the biomass-based diesel and total renewable fuel standards under EISA.

*Jatropha*

Jatropha is a genus of plants, consisting of both shrubs and trees, some of which hold promise as a feedstock for the production of biofuels. One species in particular, *Jatropha curcas*, yields seeds that contain between 25-45 percent lipids, which can be processed to produce biodiesel. The production potential of *J. curcas* has led to the popularity of the crop as a biofuel feedstock. In particular, some potential advantages include growth on marginal lands, tolerance to drought, low nutrient and labor inputs, and high oil yield.

*J. curcas* has been traditionally cultivated for living fences, to conserve soil moisture, reclaim soil, control erosion, and used locally in soap production, insecticide, and medicinal application.[147,148] Most recently, *J. curcas* has been investigated as an energy crop. *J. curcas* originated in Central America, mainly growing in arid and semi-arid conditions; now it is also found in the tropical regions of Africa, Asia, and North and South America.[149] Because of *J. curcas'* deep root system, it can grow in lands that have been previously heavily cultivated or otherwise have low levels of essential minerals and nutrients in the top levels of soil; this results in the recycling of nutrients from deeper soil levels.[150,151] In addition, because the plant is a perennial (living up to 50 years) the root system stays in place, which can significantly reduce erosion and even reverse desertification.[152,153]

As a wild plant which has not yet been domesticated, *J. curcas* has a large potential for improving many qualities, such as minimizing inputs, maximizing yields, and developing tolerance for various climates. For example, there is still little known on water use efficiency of *J. curcas* as a crop.[154] Even though *J. curcas* can survive moderate droughts by dropping its leaves, the effect of water starvation on seed yield and oil content in the seeds is mostly unknown. Water use efficiency of sister species *Jatropha pandurifolia* and *Jatropha gossypifolia* are reported as 3.68 and 2.52 mol $CO_2$/mol $H_2O$, respectively.[155] This is similar to that of other oil seed species like soybean, with a water use efficiency of 3.90 mol $CO_2$ /mol $H_2O$.[156] Thus, it is conceivable that water requirements of *J. curcas* will be similar to that of other oil seed species; although the plant may survive droughts, it may not produce efficiently or economically when it is water-deprived.[157] Obviously, further studies relating water use to crop production must be performed.

Because *J. curcas* has been observed growing on low quality soils with low nutrient amounts, it is often assumed that the plant would be able to grow as a commercial crop in these conditions. However, research indicates that *J. curcas* growth and production of seed is severely limited by soil fertility.[158,159] The long-term impact of monocultures of jatropha on soil health has also not been studied thoroughly. Some studies indicate that *J. curcas* may not be sustainable, unless specific steps are taken to ensure the plantations' long term health.[160,161]

The seed of *J. curcas*, as previously mentioned, has a lipid content of roughly 25-45 percent by weight.[162,163] Thus, assuming a seed oil content of 35 percent and an extraction efficiency of 75 percent, this would yield 404-2040 kg oil/ha or 439-2217 liter oil/ha.[164] This is somewhat higher than other oil producing crops like soybean, sesame, sunflower, rapeseed, and castor with a range of 375-1200 liter oil/ha.

Currently, *J. curcas* is present in 2 states (Florida and Hawaii) in the U.S.[165] Because of *J. curcas'* intolerance to frost, only small portions of the United States are typically considered for cultivation with current crop varieties. Areas with the most suitable climate conditions for cultivation can extend as far as 30° N in latitude; this would include the southern parts of Texas and Louisiana, and most of Florida.[166] Assuming no irrigation (as *J. curcas* is assumed to be a low-input crop), an absolute minimum of 500 mm of rainfall is required for substantial production, this occurs in the easternmost portions of Texas, and all of Louisiana and Florida.[167] The University of Florida has done some breeding and genetic manipulation of *J. curcas*, with the goal of increasing hardiness and tolerance to colder climates.[168] As research progresses and new varieties are identified, future locations for growth of *J. curcas* may be possible than currently suggested.

### *Canola*

Canola is a type of rapeseed that has been bred to produce edible oil with low levels of erucic acid and meal with low levels of toxins, allowing it to be used for livestock feed. It was developed in Canada, but is now grown in many places around the world including the United States. Currently about 1.2 million acres of canola is grown in the United States. Canola can be grown as either a spring or winter crop, with yields for winter canola being significantly higher than those for spring canola (1,500 pounds per acre vs. 3,500 pounds per acre).[169] The oil content of the canola seeds is approximately 40%. The oil produced from the canola seeds is low in saturated fat and high in omega-3 fatty acids, making it desirable for use as edible oil. These traits, combined with the higher price of canola oil result in very little canola oil being used in biodiesel production today. The high oil yields and potential for canola to be grown as a winter crop may result in an increase in canola oil production in the United States and a greater availability for its use as a biodiesel feedstock.

### *Camelina*

Camelina is an oilseed crop native to Northern Europe and Central Asia that has been grown in Europe for thousands of years for use as an edible oil as well as industrial purposes. It is primarily considered a weed in North America and is most common in the northern Midwest. Recently there has been interest in the potential use of the oil extracted from camelina seeds as a biodiesel feedstock. Camelina's suitability to northern climates, low moisture, and marginal soils allow it to be grown in areas that are unsuitable for other major oilseed crops such as soy beans, sunflower, and canola. Camelina also requires the use of few, if any, herbicides, as well as little to no tillage.[170] Camelina can also be used to break the continuous planting cycle of small grains, effectively reducing the disease, insect, and weed pressure in fields planted with wheat the following year.[171] Camelina seeds contain approximately 40% oil and have averaged yields of over 1100 kg/ha (~1000 pounds per acre) in long term trials in Rosemount, Minnesota, though future yields improvements through selective breeding are likely.[172] Camelina is currently being grown on approximately 50,000 acres of land the U.S., primarily in Montana, eastern Washington, and the Dakotas.[173]

### *Pennycress*

Pennycress is a winter annual weed currently established in every state except Hawaii, but especially prevalent in the Midwest and northwest. It has several qualities that make it a potential feedstock source for biodiesel production. Pennycress germinates in the fall and grows as a winter cover crop. Pennycress flowers and produces seeds in late April and May. These seeds can be harvested in early June, allowing the fields to be planted with soy beans. Pennycress seed yields have been as high as 2000 pounds per acre in wild stands and yield 36% oil when crushed.[174] In addition to the oil, the seeds of pennycress also contain the chemical sinigrin, which has potential uses as a bio-fumigant. The crushed pennycress seeds could be used as a weed killer for high value crops that would also provide value as a fertilizer. There are concerns, however, about the invasive nature of pennycress. Even though it does not compete directly with summer annual crops due to its growing season, there is some concern that, once established, pennycress would be very difficult to remove. It has also not been grown as a commercial crop, and little is yet known about planting and cultivation requirements.

Pennycress is currently being grown on several five to ten acre plots by BioFuels Manufacturers of Illinois. They plan to construct a 45 million gallon per year biodiesel plant in Peoria County that would use soy oil, animal fats, and vegetable oils as feedstock when it begins operation and plans to use pennycress oil as a significant feedstock source in the future.[175] While the initial attempts to grow pennycress were unsuccessful, more recent on farm trials have resulted in the successful establishment of pennycress.[176] Pennycress has a large potential as a secondary crop if its cultivation proves to be profitable.

### 1.1.3.6 Imported Biodiesel

The European Union is expected to continue as the largest consumer of biodiesel, with use projected to be almost 3 billion gallons per year by 2018.[177,178,179] Given the E.U.'s limited land suitable for oilseed crops, it is likely that a significant portion of this fuel will be either imported or made from imported feedstock.[180] During this timeframe, other significant producers of biodiesel or its feedstocks, such as Argentina, Brazil, Indonesia, and Malaysia, are expected to increase domestic use of biofuels due to mandates or simple economic advantage.[181]

Our primary control scenario projects U.S. use of biodiesel to rise to approximately 1.5 billion gallons by 2022. Given competition for imports by the E.U. and Asian markets where retail fuel prices are among the highest in the world, as well as the feasibility to produce this biofuel from domestically-sourced feedstocks (see discussion above), we do not expect imports to contribute to U.S. biodiesel for the foreseeable future. Thus, we are not assuming any imports of biodiesel for our analyses.

### 1.1.3.7 Biodiesel Feedstock Summary

Table 1.1-25 shows the volumes and uses of biodiesel and renewable diesel feedstocks as projected for the analyses in this rulemaking. Total volume here (1.67 billion gallons) fulfills the Biomass Based Diesel category requirements (1.0 billion gallons) and contributes to the Other Advanced Biofuel (0.67 billion gallons), as projected for our primary control case (see Section 1.2.2).

**Table 1.1-25.**
**Estimated 2022 Biodiesel & Renewable Diesel Volumes**
**Based on Feedstock Availability (million gallons of fuel)**

| Feedstock type | Base catalyzed biodiesel | Acid pretreatment biodiesel | Renewable diesel |
|---|---|---|---|
| Virgin vegetable oil | 660 | - | - |
| Corn oil from ethanol production | - | 680 | - |
| Rendered animal fats and greases | - | 230 | 150 |
| Algae oil or other advanced source | 100 | - | - |

## 1.2 RFS2 Biofuel Volumes

Our assessment of the renewable fuel volumes required to meet the Energy Independence and Security Act (EISA) necessitates establishing a primary set of fuel types and volumes on which to base our assessment of the impacts of the new standards. EISA contains four broad categories: cellulosic biofuel, biomass-based diesel, total advanced biofuel, and total renewable fuel. As these categories could be met with a wide variety of fuel choices, in order to assess the impacts of the rule, we projected a set of reasonable renewable fuel volumes based on our best estimate of likely fuels that could come to market.

The following subsections detail our rationale for projecting the amount and type of fuels needed to meet EISA. To assess the impacts of the increase in renewable fuel volume from business-as-usual (what is likely to have occurred without EISA), we have established reference and control cases. The reference cases are projections of renewable fuel volumes without the enactment of EISA and are described in further detail in Section 1.2.1. It is difficult to ascertain how much of the impact from the displacement of gasoline and diesel with renewable fuels might be due to the natural growth in renewable fuel use due to market forces as crude oil prices rise versus what might be forced by the RFS2 standards. Regardless, these assessments provide important information on the wider public policy considerations related to renewable fuel production and use, climate change, and national energy security. The control cases are projections of the volumes and types of renewable fuel that might be used to comply with the EISA volume mandates. For the NPRM we had focused on one primary control case whereas for the final rule we have expanded the analysis to include two additional sensitivity cases. We assume in each of the cases the same ethanol-equivalence basis as was used in the RFS1 rulemaking to meet the standard. Volumes listed in the tables for this section are in straight-gallons and allow for the reader to calculate ethanol-equivalent gallons if necessary (i.e. times 1.5 for biodiesel or 1.7 for cellulosic diesel and renewable diesel). Sections 1.2.2 and 1.2.3 aim to describe the control cases in greater detail as well as provide fuel volumes and types for years prior to 2022.

The main difference between the volumes used for the NPRM and the volumes used for the FRM is the inclusion of cellulosic diesel for the FRM. The NPRM made the simplifying assumption that the cellulosic biofuel standard would be met entirely with cellulosic ethanol. However, due to growing interest and recent developments in hydrocarbon-based or so-called “drop-in” renewable fuels as well as butanol, and marketplace challenges for consuming high volumes of ethanol, we have included projections of more non-ethanol renewables in our primary control case for the final rule.[R] In the future, this could include various forms of “green hydrocarbons” (i.e., cellulosic gasoline, diesel and jet) and higher alcohols, but for simplicity our analyses have modeled it all as cellulosic diesel fuel. We have also included some algae-derived biofuels in our FRM analyses given the large interest and potential for such fuels. We have continued to assume zero volume for renewable fuels or blendstocks such as biogas, jatropha, palm, imported cellulosic biofuel, and other alcohols or ethers in our control cases. Although we have not included these renewable fuels and blendstocks in our impact analyses, it is important to note that they can still be counted under our program if they meet the lifecycle thresholds and definitions for renewable biomass, and recent information suggests that some of them may be likely.

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[R] Comments received from Advanced Biofuels Association, Testimony on June 9, 2009 suggesting a number of advanced biofuel technologies will be able to produce renewable diesel, jet fuels, gasoline, and gasoline component fuels (e.g. butanol, iso-octane). Similar comments were received from the New York State Department of Environmental Conservation (Docket EPA-HQ-OAR-2005-0161-2143), OPEI and AllSAFE (Docket EPA-HQ-OAR-2005-0161-2241), and the Low Carbon Synthetic Fuels Association (Docket EPA-HQ-OAR-2005-0161-2310).

### 1.2.1 Reference Cases

Our primary reference case renewable fuel volumes are based on the Energy Information Administration's (EIA) Annual Energy Outlook (AEO) 2007 reference case projections.[S] While AEO 2007 is not as up-to-date as AEO 2008 or AEO 2009, we chose to use AEO 2007 because later versions of AEO already include the impact of increased renewable fuel volumes under EISA as well as fuel economy improvements under CAFE as required in EISA, whereas AEO 2007 did not.

For the final rule we also assessed a number of the impacts relative to the reference case assuming the mandated renewable fuel volumes under RFS1 from the Energy Policy Act of 2005 (EPAct). This allows for a more complete assessment of the impacts of the EISA volume mandates, especially when combined with the impacts assessment conducted for the RFS1 rulemaking (though many factors have changed since then). Table 1.2-1 and Table 1.2-2 summarize the renewable fuel volumes for years 2022 and prior, for the AEO 2007 and the RFS1 reference cases, respectively.

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[S] AEO 2007 was only used to derive renewable fuel volume projections for the primary reference case. AEO 2009 was used for future crude oil cost estimates and for estimating total transportation fuel energy use.

### Table 1.2-1. AEO 2007 Reference Case Renewable Fuel Volumes (billion gallons)

| | Advanced Biofuel | | | Non-Advanced Biofuel | Total Renewable Fuel |
|---|---|---|---|---|---|
| | Cellulosic Biofuel | Biomass-Based Diesel[a] | Other Advanced Biofuel | | |
| Year | Cellulosic Ethanol[c] | FAME Biodiesel[b] | Imported Ethanol | Corn Ethanol | |
| 2010 | 0.12 | 0.32 | 0.29 | 10.49 | 11.22 |
| 2011 | 0.19 | 0.33 | 0.16 | 10.69 | 11.37 |
| 2012 | 0.25 | 0.33 | 0.18 | 10.81 | 11.57 |
| 2013 | 0.25 | 0.33 | 0.19 | 10.93 | 11.70 |
| 2014 | 0.25 | 0.23 | 0.20 | 11.01 | 11.69 |
| 2015 | 0.25 | 0.25 | 0.39 | 11.10 | 11.99 |
| 2016 | 0.25 | 0.35 | 0.51 | 11.16 | 12.27 |
| 2017 | 0.25 | 0.36 | 0.53 | 11.30 | 12.44 |
| 2018 | 0.25 | 0.36 | 0.54 | 11.49 | 12.64 |
| 2019 | 0.25 | 0.37 | 0.58 | 11.69 | 12.89 |
| 2020 | 0.25 | 0.37 | 0.60 | 11.83 | 13.05 |
| 2021 | 0.25 | 0.38 | 0.63 | 12.07 | 13.33 |
| 2022 | 0.25 | 0.38 | 0.64 | 12.29 | 13.56 |

[a] Biomass-Based Diesel could include FAME biodiesel, cellulosic diesel, and non-co-processed renewable diesel.

[b] Only fatty acid methyl ester (FAME) biodiesel volumes were considered

[c] AEO 2007 reference case assumes actual production of cellulosic biofuel (i.e. not corn ethanol plants utilizing 90% biomass for energy) and therefore was assumed to be 0.25 billion gallons.

### Table 1.2-2. RFS1 Reference Case Renewable Fuel Volumes (billion gallons)

| | Advanced Biofuel | | | Non-Advanced Biofuel | Total Renewable Fuel |
|---|---|---|---|---|---|
| | Cellulosic Biofuel | Biomass-Based Diesel[a] | Other Advanced Biofuel | | |
| Year | Cellulosic Ethanol[c] | FAME Biodiesel[b] | Imported Ethanol | Corn Ethanol | |
| 2010 | n/a | n/a | n/a | n/a | n/a |
| 2011 | n/a | n/a | n/a | n/a | n/a |
| 2012 | 0.00 | 0.303 | 0.00 | 7.046 | 7.35 |
| 2013 | 0.00 | 0.303 | 0.00 | 7.046 | 7.35 |
| 2014 | 0.00 | 0.303 | 0.00 | 7.046 | 7.35 |
| 2015 | 0.00 | 0.303 | 0.00 | 7.046 | 7.35 |
| 2016 | 0.00 | 0.303 | 0.00 | 7.046 | 7.35 |
| 2017 | 0.00 | 0.303 | 0.00 | 7.046 | 7.35 |
| 2018 | 0.00 | 0.303 | 0.00 | 7.046 | 7.35 |
| 2019 | 0.00 | 0.303 | 0.00 | 7.046 | 7.35 |
| 2020 | 0.00 | 0.303 | 0.00 | 7.046 | 7.35 |
| 2021 | 0.00 | 0.303 | 0.00 | 7.046 | 7.35 |
| 2022 | 0.00 | 0.303 | 0.00 | 7.046 | 7.35 |

[a] Biomass-Based Diesel could include FAME biodiesel, cellulosic diesel, and non-co-processed renewable diesel.

[b] Only fatty acid methyl ester (FAME) biodiesel volumes were considered

[c] Under the RFS 1 reference case, we assumed the 250-million gallon cellulosic standard set by EPAct would be met primarily by corn ethanol plants utilizing 90% biomass for energy, thus actual production of cellulosic biofuel is zero.

### 1.2.2 Primary Control Case

Table 1.2-3 summarizes the fuel types and volumes for the primary control case for the years 2010-2022. Although actual volumes and feedstocks will likely be different, we believe the projections made here are within the range of expected outcomes when the standards are met and allow for an assessment of the potential impacts of the RFS2 rule. More details on contributions of different feedstock types within the renewable fuel categories here can be found in Section 1.1.

## Table 1.2-3.
## Primary Control Case Projected Renewable Fuel Volumes (billion gallons)

| | **Advanced Biofuel** | | | | | | **Non-Advanced Biofuel** | **Total Renewable Fuel**[f] |
|---|---|---|---|---|---|---|---|---|
| | **Cellulosic Biofuel** | | **Biomass-Based Diesel**[a] | | **Other Advanced Biofuel** | | | |
| **Year** | **Cellulosic Ethanol** | **Cellulosic Diesel**[b] | **FAME**[c] **Biodiesel** | **NCRD**[d] | **Other Biodiesel**[e] | **Imported Ethanol** | **Corn Ethanol** | |
| 2010 | 0.03 | 0.04 | 0.61 | 0.04 | 0.22 | 0.29 | 11.24 | 12.48 |
| 2011 | 0.08 | 0.10 | 0.72 | 0.08 | 0.17 | 0.16 | 12.07 | 13.38 |
| 2012 | 0.15 | 0.20 | 0.92 | 0.08 | 0.12 | 0.18 | 12.83 | 14.48 |
| 2013 | 0.31 | 0.41 | 0.92 | 0.08 | 0.28 | 0.19 | 13.42 | 15.61 |
| 2014 | 0.54 | 0.71 | 0.85 | 0.15 | 0.39 | 0.20 | 14.09 | 16.93 |
| 2015 | 0.92 | 1.22 | 0.85 | 0.15 | 0.53 | 0.39 | 14.79 | 18.85 |
| 2016 | 1.31 | 1.73 | 0.85 | 0.15 | 0.56 | 0.63 | 15.00 | 20.23 |
| 2017 | 1.69 | 2.24 | 0.85 | 0.15 | 0.60 | 1.07 | 15.00 | 21.60 |
| 2018 | 2.15 | 2.85 | 0.85 | 0.15 | 0.64 | 1.51 | 15.00 | 23.15 |
| 2019 | 2.61 | 3.46 | 0.85 | 0.15 | 0.68 | 1.96 | 15.00 | 24.71 |
| 2020 | 3.23 | 4.28 | 0.85 | 0.15 | 0.72 | 1.88 | 15.00 | 26.11 |
| 2021 | 4.15 | 5.50 | 0.85 | 0.15 | 0.77 | 1.81 | 15.00 | 28.23 |
| 2022 | 4.92 | 6.52 | 0.85 | 0.15 | 0.82 | 2.24 | 15.00 | 30.50 |

[a] Biomass-Based Diesel could include FAME biodiesel, cellulosic diesel, and non-co-processed renewable diesel.

[b] Cellulosic Diesel includes 1.96 billion gallons from Fischer-Tropsch Biomass-to-Liquids (BTL) processes and 4.56 billion gallons from this or other types of cellulosic diesel processes in year 2022. In order to calculate the split of cellulosic ethanol vs. cellulosic diesel in years prior to 2022, we assumed the same percentage of the total cellulosic biofuel standard as in year 2022, i.e. 31% cellulosic ethanol and 69% cellulosic diesel.

[c] Fatty acid methyl ester (FAME) biodiesel

[d] Non-Co-processed Renewable Diesel (NCRD)

[e] Other Biodiesel is biodiesel that could be produced in addition to the amount needed to meet the biomass-based diesel standard.

[f] May not total due to rounding.

#### 1.2.2.1 Cellulosic Biofuel

As defined in EISA, cellulosic biofuel means renewable fuel produced from any cellulose, hemicellulose, or lignin that is derived from renewable biomass and that has lifecycle greenhouse gas emissions, as determined by the Administrator, that are at least 60% less than the baseline lifecycle greenhouse gas emissions.

When many people think of cellulosic biofuel, they immediately think of cellulosic ethanol. However, cellulosic biofuel could be comprised of other alcohols, synthetic gasoline, synthetic diesel fuel or heating oil, and synthetic jet fuel, propane, and biogas. Whether cellulosic biofuel is ethanol will depend on a number of factors, including production costs, the form of tax subsidies, credit programs, and issues associated with blending the biofuel into the fuel pool. For instance, under the Farm Bill of 2008, both cellulosic ethanol and cellulosic diesel receive the same tax subsidies ($1.01 per gallon each). The tax subsidy, however, gives ethanol producers a considerable advantage over those producing cellulosic diesel due to the feedstock quantity needed per gallon produced (i.e. typically the higher the energy content of the product, the more feedstock that is required). On an energy basis, cellulosic ethanol would receive approximately $13/mmBtu while cellulosic diesel would receive approximately $8/mmBtu. It will also depend on the relative demand for gasoline and diesel fuel. For example, European refineries have been undersupplying the European market with diesel fuel supply and oversupplying it with gasoline, and based on the recent diesel fuel price margins over gasoline, it seems that the U.S. is falling in line with Europe. Therefore, if the U.S. trend is toward being relatively oversupplied with gasoline, there could be a price advantage towards producing renewable fuels that displace diesel fuel rather than a gasoline fuel replacement like ethanol.

One large advantage that cellulosic diesel has over ethanol is the ability for the fuel to be blended easily into the current distribution infrastructure at sizeable volumes. There are currently factors tending to limit the amount of ethanol that can be blended into the fuel pool (see Section 1.7. of the RIA for more discussion). Thus, the production of cellulosic diesel instead of cellulosic ethanol could help increase consumption of renewable fuels.

Cellulosic biofuel could also be produced internationally. One example of internationally produced cellulosic biofuel is ethanol produced from bagasse from sugarcane processing in Brazil. Currently, Brazil burns bagasse to produce steam and generate bioelectricity. However, improving efficiencies over the coming decade as well as mechanization of sugarcane harvesting (no burning of biomass in fields) may allow an increasing portion of bagasse to be allocated to other uses, including cellulosic biofuel, as additional straw could potentially be collected and used to produce bioelectricity. Although international production of cellulosic biofuel is possible, it is uncertain whether this supply would be available primarily to the U.S. or whether other nations would consume the fuel domestically. Therefore, our analyses for cellulosic biofuel primarily focus on North America, and for our impact analyses just on domestic supplies.

As discussed, there is uncertainty as to which mix of cellulosic biofuels will be produced to fulfill the 16 Bgal mandate by 2022. For assessing the impacts of the RFS2 standards, we used AEO 2009 (April release) cellulosic ethanol volumes (4.92 billion gallons), as well as the cellulosic biomass-to-liquids (BTL) diesel volumes (1.96 billion gallons) using Fischer-Tropsch

(FT) processes. We consider BTL diesel from FT processes as a subset of cellulosic diesel. In order to reach a total of 16 billion ethanol-equivalent gallons, we assumed that an additional 4.56 billion gallons of cellulosic diesel could be produced from BTL or other cellulosic diesel processes.

### 1.2.2.2 Biomass-Based Diesel

Biomass-based diesel as defined in EISA means renewable fuel that is biodiesel as defined in section 312(f) of the Energy Policy Act of 1992 with lifecycle greenhouse gas emissions, as determined by the Administrator, that are at least 50% less than the baseline lifecycle greenhouse gas emissions. Biomass-based diesel can include fatty acid methyl ester (FAME) biodiesel, renewable diesel (RD) that has not been co-processed with a petroleum feedstock, as well as cellulosic diesel. Although cellulosic diesel produced through the Fischer-Tropsch (F-T) process or other processes could potentially contribute to the biomass-based diesel category, we have assumed for our analyses that the fuel and its corresponding feedstocks (cellulosic biomass) are already accounted for in the cellulosic biofuel category as discussed in the previous Section 1.2.2.1.

FAME and RD processes can make acceptable quality fuel from vegetable oils, fats, and greases, and thus will generally compete for the same feedstock pool. For our analyses, we have assumed that the volume contribution from FAME biodiesel and RD will be a function of the available feedstock types. For our analysis we assumed that virgin plant oils would be preferentially processed by biodiesel plants. Other feedstocks assumed to be used by biodiesel plants are fuel-grade corn oil from corn oil extraction, fats, waste oils, and waste greases. For the FRM we have also included a small volume of oil feedstock from algae for biodiesel production. We note that there are a wide range of new feedstocks being researched and developed for the production of biodiesel, e.g. camelina and pennycress. While these new feedstocks may prove to be commercially available in the future, we have not assumed that they are used for analyses purposes.

For RD, we assumed that the feedstocks used are from fats, waste oils, and waste greases. This is because the RD process involves hydrotreating (or thermal depolymerization), which is more severe and uses multiple chemical mechanisms to reform the fat molecules into diesel range material. The FAME process, by contrast, relies on more specific chemical mechanisms and requires pre-treatment if the feedstocks contain more than trace amounts of free fatty acids or other contaminates which are typical of recycled fats and greases. In terms of volume availability of feedstocks, supplies of fats, waste oils, and waste greases are more limited than virgin vegetable oils. As a result, our control case assumes the majority of biomass-based diesel volume is met using biodiesel facilities processing vegetable oils, with RD making up a smaller portion and using solely fats, waste oils, and waste greases.

The RD production volume must be further classified as co-processed or non-co-processed, depending on whether the renewable material was mixed with petroleum during the hydrotreating operation. EISA specifically forbids co-processed RD from being counted as biomass-based diesel, but it can still count toward the total advanced biofuel requirement. What fraction of RD will ultimately be co-processed is uncertain at this time, since little or no commercial production of RD is currently underway, and little public information is available about the comparative economics and feasibility of the two methods. Current industry plans indicate, however, that co-processing renewable diesel may not be as favorable as non-co-processed RD, and therefore, we have chosen to assume zero volumes of co-processed RD.[T] Non-co-processed RD volumes are based on production plans from Syntroleum.

### 1.2.2.3 Other Advanced Biofuel

As defined in EISA, advanced biofuel means renewable fuel, other than ethanol derived from corn starch, that has lifecycle greenhouse gas emissions, as determined by the Administrator, that are at least 50% less than baseline lifecycle greenhouse gas emissions. As defined in EISA, advanced biofuel includes the cellulosic biofuel, biomass-based diesel, and co-processed renewable diesel categories that were mentioned in Section 1.2.2.1 and Section 1.2.2.2 above. However, EISA requires greater volumes of advanced biofuel than just the volumes required of these fuels. It is entirely possible that greater volumes of cellulosic biofuel, biomass-based diesel, and co-processed renewable diesel than required by the Act could be produced in the future. Our control case assumes that the cellulosic biofuel volumes will not exceed those required under EISA. We do assume, however, that additional biodiesel than that needed to meet the biomass-based diesel volume will be used to meet the total advanced biofuel volume. Despite additional volumes assumed from biodiesel, to fully meet the total advanced biofuel volume required under EISA, other types of advanced biofuel are necessary through 2022.

We have assumed for the analyses conducted that for our control case the most likely source of advanced fuel other than cellulosic biofuel and biomass-based diesel would be from imported sugarcane ethanol and perhaps limited amounts of co-processed renewable diesel. Our assessment of international fuel ethanol production and demand indicate that anywhere from 3.8-4.2 Bgal of sugarcane ethanol from Brazil could be available for export by 2020/2022. If this volume were to be made available to the U.S., then there would be sufficient volume to meet the advanced biofuel standard. To calculate the amount of imported ethanol needed to meet the EISA advanced biofuel standards, we assumed it would make up the difference not met by cellulosic biofuel, biomass-based diesel and additional biodiesel categories. The amount of imported ethanol required by 2022 is approximately 2.2 Bgal.[U] Refer to Section 1.5.2 for a more detailed discussion on imported ethanol.

Recent news indicates that there are also plans for sugarcane ethanol to be produced in the U.S in places where the sugar subsidy does not apply. For instance, sugarcane has been grown in California’s Imperial Valley specifically for the purpose of making ethanol and using the cane’s biomass to generate electricity to power the ethanol distillery as well as export excess electricity to the electric grid.[V] There are at least two projects being developed at this time that

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[T] On May 13, 2009 ConocoPhillips and Tyson suspended plans for building RD co-processing facilities. The tax credit for RD co-processing that helped fund the project was cut from $1 a gallon to 50 cents a gallon as part of the credit bill approved by Congress and signed by President Bush in late 2008. The non-co-processing tax credit remains at $1 a gallon.

[U] The exceptions were for the years from 2010-2015 in the control case, where we assumed AEO 2007 imported ethanol volumes; otherwise, imported ethanol volumes would be zero and lower than the reference case volumes.

[V] Personal communication with Nathalie Hoffman, Managing Member of California Renewable Energies, LLC, August 27, 2008 could result in several hundred million gallons of ethanol produced. The sugarcane is being grown on marginal and existing cropland that is unsuitable for food crops and will replace forage crops like alfalfa, Bermuda grass, Klein grass, etc. Harvesting is expected to be fully mechanized. Thus, there is potential for these projects and perhaps others to help contribute to the EISA biofuels mandate. This could lower the volume needed to be imported from Brazil.

Butanol is another potential motor vehicle fuel which could be produced from biomass and used in lieu of ethanol to comply with the RFS2 standard. Production of butanol is being pursued by a number of companies including a partnership between BP and Dupont. Other companies which have expressed the intent to produce biobutanol are Baer Biofuels and Gevo. The near term technology being pursued for producing butanol involves fermentation of starch compounds, although it can also be produced from cellulose. Butanol has several inherent advantages compared to ethanol. First, it has higher energy density than ethanol which would improve fuel economy (mpg). Second, butanol is much less water soluble which may allow the butanol to be blended in at the refinery and the resulting butanol-gasoline blend then more easily shipped through pipelines. This would reduce distribution costs associated with ethanol's need to be shipped separately from its gasoline blendstock and also save on the blending costs incurred at the terminal. Third, butanol contains less oxygen, allowing it to be blended in higher concentrations than 10% which would likely allow butanol to be blended with gasoline at high enough concentrations to avoid the need for most or all of high concentration ethanol-gasoline blends, such as E85, that require the use of fuel flexible vehicles. Thus, butanol would enable achieving most of the RFS2 standard by blending a lower concentration of renewable fuel than having to resort to a sizable volume of E85 as in the case of ethanol. The need to blend ethanol as E85 provides some difficult challenges. The use of butanol may be one means of avoiding these blending difficulties.

At the same time, butanol has a couple of less desirable aspects relative to ethanol. First, butanol is lower in octane compared to ethanol – ethanol has a very high blending octane of around 115, while butanol's octane ranges from 87 octane numbers for normal butanol and 94 octane numbers for isobutanol. Potential butanol producers are likely to pursue producing isobutanol over normal butanol because of isobutanol's higher octane content. Higher octane is a valuable attribute of any gasoline blendstock because it helps to reduce refining costs. A second negative property of butanol is that it has a much higher viscosity compared to either gasoline or ethanol. High viscosity makes a fuel harder to pump, and more difficult to atomize in the combustion chamber in an internal combustion engine. The third downside to butanol is that it is more expensive to produce than ethanol, although the higher production cost is partially offset by its higher energy density.

Another potential source of renewable transportation fuel is biomethane refined from biogas. Biogas is a term meaning a combustible mixture of methane and other light gases derived from biogenic sources. It can be combusted directly in some applications, but for use in highway vehicles it is typically purified to closely resemble fossil natural gas for which the vehicles are typically designed. The definition of biogas as given in EISA is sufficiently broad to cover combustible gases produced by biological decomposition of organic matter, as in a landfill or wastewater treatment facility, as well as those produced via thermochemical processing of biomass.

Currently, the largest source of biogas is landfill gas collection, where the majority of fuel is combusted to generate electricity, with a small portion being upgraded to methane suitable for use in heavy duty vehicle fleets. Current literature suggests approximately 24 billion ethanol-equivalent gallons of biogas (referring to energy content) could potentially be produced in the long term, with about two thirds coming from biomass gasification and about one third coming from waste streams such as landfills and human and animal sewage digestion.[182, 183] Because the majority of the biogas volume estimates assume biomass as a feedstock, we have chosen not to include this fuel in our analyses since we are projecting most available biomass will be used for cellulosic liquid biofuel production in the long term. The remaining biogas potentially available from waste-related sources would come from a large number of small streams requiring purification and connection to storage and/or distribution facilities, which would involve significant economic hurdles. An additional and important source of uncertainty is whether there would be a sufficient number of vehicles configured to consume these volumes of biogas. Thus, we expect future biogas fuel streams to continue to find mostly non-transportation uses such as electrical power generation or facility heating.

#### 1.2.2.4 Other Renewable Fuel

The remaining portion of total renewable fuel not met with advanced biofuel is assumed to come from corn-based ethanol (including small amounts from other starch grains and waste sugars). EISA effectively sets a limit for participation in the RFS program of 15 Bgal of corn ethanol, and we are assuming for our analysis that sufficient corn ethanol will be produced to meet the 15-Bgal limit that either meets the 20% GHG threshold or is grandfathered. It should be noted, however, that there is no specific “corn-ethanol” mandated volume, and that any advanced biofuel produced above and beyond what is required for the advanced biofuel requirements could reduce the amount of corn ethanol needed to meet the total renewable fuel standard. This occurs in our projections during the earlier years (2010-2015) in which we project that some fuels could compete favorably with corn ethanol (e.g. biodiesel and imported ethanol). Beginning around 2016, fuels qualifying as advanced biofuels likely will be devoted to meeting the increasingly stringent volume mandates for advanced biofuel. It is also important to note that more than 15 Bgal of corn ethanol could be produced and RINs generated for that volume under the RFS2 regulations. However, obligated parties would not be required to purchase more than 15 Bgal worth of non-advanced biofuel RINs, e.g. corn ethanol RINs.

We are assuming for our analysis that sufficient corn ethanol will be produced to meet the 15 Bgal limit. This assumes that corn ethanol plants are constructed or modified to meet the 20% GHG threshold, or that sufficient corn ethanol production exists that is grandfathered and not required to meet the 20% threshold. Our current projection is that up to 15 Bgal could be grandfathered, but actual volumes will be determined at the time of facility registration. Refer to Section 1.5.1.4 for more information.

### 1.2.3 Additional Control Cases Considered

Since there is significant uncertainty for what fuels will be produced to meet the 16 billion gallon cellulosic biofuel standard, we have decided to investigate two other sensitivity cases for our cost and emission impact analyses conducted for the rule. The first case, we refer to as the “low-ethanol” control case and assume only 250 million gallons of cellulosic ethanol (from AEO 2007 reference case). The rest of the 16 billion gallon cellulosic biofuel standard is made up of cellulosic diesel (9.26 billion gallons), as shown in Table 1.2-4. The second case, we refer to as the “high-ethanol” control case and assume the entire 16 billion gallon cellulosic biofuel standard is met with cellulosic ethanol, see Table 1.2-5.

## Table 1.2-4.
## Low-Ethanol Control Case Projected Renewable Fuel Volumes (billion gallons)

| Year | Advanced Biofuel | | | | | | Non-Advanced Biofuel | Total Renewable Fuel[f] |
|---|---|---|---|---|---|---|---|---|
| | Cellulosic Biofuel | | Biomass-Based Diesel[a] | | Other Advanced Biofuel | | | |
| | Cellulosic Ethanol | Cellulosic Diesel[b] | FAME[c] Biodiesel | NCRD[d] | Other Biodiesel[e] | Imported Ethanol | Corn Ethanol | |
| 2010 | 0.00 | 0.06 | 0.61 | 0.04 | 0.22 | 0.29 | 11.24 | 12.47 |
| 2011 | 0.00 | 0.14 | 0.72 | 0.08 | 0.17 | 0.16 | 12.07 | 13.35 |
| 2012 | 0.01 | 0.29 | 0.92 | 0.08 | 0.12 | 0.18 | 12.83 | 14.42 |
| 2013 | 0.02 | 0.58 | 0.92 | 0.08 | 0.28 | 0.19 | 13.42 | 15.49 |
| 2014 | 0.03 | 1.01 | 0.85 | 0.15 | 0.39 | 0.20 | 14.09 | 16.72 |
| 2015 | 0.05 | 1.74 | 0.85 | 0.15 | 0.53 | 0.39 | 14.79 | 18.49 |
| 2016 | 0.07 | 2.46 | 0.85 | 0.15 | 0.56 | 0.63 | 15.00 | 19.72 |
| 2017 | 0.09 | 3.18 | 0.85 | 0.15 | 0.60 | 1.07 | 15.00 | 20.94 |
| 2018 | 0.11 | 4.05 | 0.85 | 0.15 | 0.64 | 1.51 | 15.00 | 22.31 |
| 2019 | 0.13 | 4.92 | 0.85 | 0.15 | 0.68 | 1.96 | 15.00 | 23.69 |
| 2020 | 0.16 | 6.08 | 0.85 | 0.15 | 0.72 | 1.88 | 15.00 | 24.85 |
| 2021 | 0.21 | 7.82 | 0.85 | 0.15 | 0.77 | 1.81 | 15.00 | 26.61 |
| 2022 | 0.25 | 9.26 | 0.85 | 0.15 | 0.82 | 2.24 | 15.00 | 28.57 |

[a] Biomass-Based Diesel could include FAME biodiesel, cellulosic diesel, and non-co-processed renewable diesel.

[b] Cellulosic Diesel includes 1.96 billion gallons from Fischer-Tropsch Biomass-to-Liquids (BTL) processes and 4.56 billion gallons from this and other types of cellulosic diesel processes in year 2022. In order to calculate the split of cellulosic ethanol vs. cellulosic diesel in years prior to 2022, we assumed the same percentage of the total cellulosic biofuel standard as in year 2022, i.e. 2% cellulosic ethanol and 98% cellulosic diesel.

[c] Fatty acid methyl ester (FAME) biodiesel

[d] Non-Co-processed Renewable Diesel (NCRD)

[e] Other Biodiesel is biodiesel that could be produced in addition to the amount needed to meet the biomass-based diesel standard.

[f] May not total due to rounding.

## Table 1.2-5.
## High-Ethanol Control Case Projected Renewable Fuel Volumes (billion gallons)

| Year | Advanced Biofuel | | | | | | Non-Advanced Biofuel | Total Renewable Fuel[f] |
|---|---|---|---|---|---|---|---|---|
| | Cellulosic Biofuel | | Biomass-Based Diesel[a] | | Other Advanced Biofuel | | | |
| | Cellulosic Ethanol | Cellulosic Diesel[b] | FAME[c] Biodiesel | NCRD[d] | Other Biodiesel[e] | Imported Ethanol | Corn Ethanol | |
| 2010 | 0.10 | 0.00 | 0.61 | 0.04 | 0.22 | 0.29 | 11.24 | 12.51 |
| 2011 | 0.25 | 0.00 | 0.72 | 0.08 | 0.17 | 0.16 | 12.07 | 13.45 |
| 2012 | 0.50 | 0.00 | 0.92 | 0.08 | 0.12 | 0.18 | 12.83 | 14.62 |
| 2013 | 1.00 | 0.00 | 0.92 | 0.08 | 0.28 | 0.19 | 13.42 | 15.89 |
| 2014 | 1.75 | 0.00 | 0.85 | 0.15 | 0.39 | 0.20 | 14.09 | 17.43 |
| 2015 | 3.00 | 0.00 | 0.85 | 0.15 | 0.53 | 0.39 | 14.79 | 19.70 |
| 2016 | 4.25 | 0.00 | 0.85 | 0.15 | 0.56 | 0.63 | 15.00 | 21.44 |
| 2017 | 5.50 | 0.00 | 0.85 | 0.15 | 0.60 | 1.07 | 15.00 | 23.17 |
| 2018 | 7.00 | 0.00 | 0.85 | 0.15 | 0.64 | 1.51 | 15.00 | 25.15 |
| 2019 | 8.50 | 0.00 | 0.85 | 0.15 | 0.68 | 1.96 | 15.00 | 27.13 |
| 2020 | 10.50 | 0.00 | 0.85 | 0.15 | 0.72 | 1.88 | 15.00 | 29.11 |
| 2021 | 13.50 | 0.00 | 0.85 | 0.15 | 0.77 | 1.81 | 15.00 | 32.08 |
| 2022 | 16.00 | 0.00 | 0.85 | 0.15 | 0.82 | 2.24 | 15.00 | 35.06 |

[a] Biomass-Based Diesel could include FAME biodiesel, cellulosic diesel, and non-co-processed renewable diesel.

[b] Cellulosic Diesel is assumed to be zero, while cellulosic ethanol is assumed to be 100% of the cellulosic biofuel standard.

[c] Fatty acid methyl ester (FAME) biodiesel

[d] Non-Co-processed Renewable Diesel (NCRD)

[e] Other Biodiesel is biodiesel that could be produced in addition to the amount needed to meet the biomass-based diesel standard.

[f] May not total due to rounding.

## 1.3 Feedstock Harvesting, Transportation, & Storage

A reliable and affordable source of cellulosic feedstocks will be vital for the development of a large scale cellulosic biofuel industry. While Section 1.1 of the RIA examined the availability of cellulosic feedstocks for conversion to biofuels, this section focuses instead on the process of harvesting, storing, and transporting these feedstocks to the biofuel production facilities. For biofuels that use traditional crops such as corn, soy bean oil, or sugar cane, these feedstock storage and delivery systems are already well established. For other feedstocks, however, such as herbaceous energy crops or wood residue, new feedstock supply systems will have to be put into place. Each of these potential feedstocks presents unique challenges that must be overcome in order for them to be used for large scale biofuel production. For more information on the costs associated with the harvest, storage, and transportation processes see Chapter 4 of the RIA.

### 1.3.1 Feedstock Harvesting

Feedstock harvesting refers to all the steps necessary to make the feedstock available at the roadside for transportation and storage. For MSW, this is a relatively simple process. MSW is already collected on a large scale and in order to enable it to be used as a feedstock all that is required is that it be sorted to remove the portion that is undesirable for biofuel production. Agricultural residues and herbaceous energy crops, on the other hand, are not currently being harvested on a large scale and therefore new processes must be developed to make them available to be used in the production of biofuels.

#### 1.3.1.1 Municipal Solid Waste (MSW) Collection

As discussed above, MSW is one of the potential sources of renewable fuel feedstock that already has a well developed collection system already in place. In many cases cities and municipalities are already recovering recyclable materials, such as metals, plastics, and paper, from the collected waste streams. After these valuable materials have been removed from the waste stream the remainder of the waste material can, in many cases, be used for the production of renewable with little or no additional separation required. Alternatively, a waste stream of similar quality may be able to be obtained without the potentially expensive separation process if the waste material is separated by the waste producer at the curbside. One potential producer of biofuels from MSW indicated in a confidential conversation that this was the method they planned to use to obtain their feedstock.

In parts of the country where these recyclable materials are not currently recovered it will be necessary for the biofuel producer who wishes to use this material to first remove the metals, plastics, and other contaminated materials before this material may be used. This sorting can be done either by hand or with an automated process. Cleaner streams are produced when the waste stream is sorted by hand, however this is a slower and more expensive process. Potential biofuel producers indicated to us that the automated separation systems that currently exist produce waste streams of acceptable quality and are thus more likely to be used due to their lower costs. If the biofuel producer was responsible for waste separation it is likely that the separation facility and the biofuel production facility would be located at the same site, and thus no transportation would be necessary between these two facilities.

### 1.3.1.2 Wood Residue Collection and Harvest

Another potential source of feedstock that may be converted to cellulosic biofuels are wood residues. This category of feedstock refers to a large range of currently unused wood wastes from forestry and wood processing industries. Significant sources of wood residue are either currently available or expected to be available in the near future in the form of mill residues, forest residue, and forestry thinnings.

*Mill Residue*

One source of currently available wood residue is mill residue. Mill residue is a waste product of both primary mills, mills that convert roundwood into other wood products, and secondary mills, those that produce finished consumer products. Because this residue is currently being produced at the primary and secondary mills all that would be required for its use as a cellulosic biofuel feedstock is it's collection and transportation to the biofuel production facility or for the co-located construction of a biofuel facility.

*Forest Residue*

The largest portion of wood residue available as cellulosic feedstock is forest residues. However, unlike residues such as primary or secondary mill residues that could be available on-site at a processing facility, forestry residues would need to be collected and transported similarly to conventional forest products. The amount of residues potentially available is a function of harvest amount, logging method, and type and location of timberlands.[184] In addition, residue availability is limited by economic factors. According to one study, "the actual operations of harvesting, collecting, processing and transporting loose forest residues are costly and present an economic barrier to recovery and utilization of wood for energy".[185] Thus, there are still challenges that need to be addressed before large-scale use of forestry residues is possible.

Currently, the most cost-effective method of recovering forest residue for biomass is in-woods chipping.[186] This method is suitable for operations where there is whole-tree skidding to roadside, good road access to chip vans and chippers, and sufficient biomass volume per acre. However, in-woods chipping systems are not as effective when ground-based skidding is restricted or when there are no merchantable products other than biomass. In addition, the chip vans designed to haul wood chips were built for highway use and often do not have sufficient suspension systems for remote forest roads. There are also high costs for wood grinders with low production rates.[187] Fortunately, there have been developments in alternative methods to reduce the costs of biomass collection systems.

There has been much focus recently on developing methods of densifying residues in order to increase productivity of handling operations (i.e. hauling, skidding, and loading). New approaches to removing forestry residues are currently being evaluated (e.g. slash bundling machines, horizontal grinders, and roll on/off container transport). One of the advantages of using slash bundling machines is the ability to store biomass longer than in chip form. Storing biomass at roadside in the form of biomass bundles could provide a more secure and stable biomass supply than with chips which are smaller and have greater surface area for potential weathering. Utilizing roll on/off containers allows for recovery of residue from difficult-to-access locations and in such situations could be competitive with regular highway chip vans.

While these are just some of the ways to improve recovery operations for forestry residues, these methods still have challenges. For example, there are some difficulties with bundling of brittle residues or short, large diameter pieces. In addition, some residues may include rocks or trash that can result in additional saw maintenance and reduced utilization. With millions of acres of forest, there is no single residue treatment option that will meet the needs of all situations. Forest land managers will need to weigh the different options for dealing with forest residues to determine the most cost-effective means for residue removal in their specific locations.

*Forest Thinnings*

A third source of wood residue is forestry thinnings. Forest thinnings refer to woody material removed from forests that have become overgrown, either to reduce the risk of forest fires or to increase productivity of the forest. The material removed is too small or damaged in some other way and is unsuitable to be sold as roundwood. Because of its low value, much of the wood residue removed from forests today as forest thinnings is either burned or left to decompose. Currently the cost to fell the thinnings is paid for by the land owner. Therefore, in order to use this material as a cellulosic feedstock the forest thinnings would only have to be collected from the forest and moved to the roadside. Once at the roadside they would likely be either chipped or bundled using the process previously discussed to increase the density of the thinnings, and thus reduce the transportation costs.

### 1.3.1.3 Agricultural Residue Harvest

Agricultural residue is a very large and potentially readily available cellulosic feedstock source for biofuels producers. While the residues of some crops have been harvested for many years, much crop residue is left on the fields in order in increase soil quality and protect against erosion from wind and rain as discussed in Section 1.1. Despite the many benefits of leaving agricultural residue on the fields we believe that it is possible to remove some portion of the agricultural residues without significant negative impacts to the soil quality in many parts of the country. We also believe that agricultural residues will make up a large portion of the cellulosic feedstocks used for biofuel production by 2022. The following section discusses the likely process for agricultural residue harvest and the associated challenges we anticipate. We have chosen to focus our discussion on corn stover as it is expected that it will be used more extensively than any other agricultural residue, and because there is more uncertainty surrounding its harvest than other small grains, such as wheat, oats, barley, and rice, that are regularly harvested currently.

Corn stover harvest, at present, requires multiple machines: combines, shredders, rakes, balers, bale wagons, and stackers just to get the stover bales to the side of the field; dry matter is lost during each operation. Currently, there are no harvesting machines designed specifically for residue harvest, other than perhaps, for small grain straws that use common hay equipment. One proposal for corn stover harvest is to shut the spreader off on the grain combine in order to form a windrow, of sorts, following which the windrow is baled.[188] However, modern combines leave most of the stalk standing. In order to harvest as much of the stover as possible, it is necessary to shred the standing stalks and then rake all of it together prior to baling.[189] The baler pickup must be set high enough to avoid picking up dirt and dirt clods, the dirt-particles from which are very hard on harvesting equipment and that would demand a cleanup stage in downstream processing, which of itself would translate into overall dry matter losses. As such, it is likely that the baler will leave some amount of stover. After baling, the bales, whether round or square, would be picked up from the field and moved to the roadside, where they would await transportation to a storage facility.

We anticipate that by 2022, the corn stover harvest will be reduced to a single-pass operation during which the amount of residue left on the field will be less a function of harvest efficiency and more a function of the farmer/grower and the harvesting company being able to determine how much residue must be left to maintain soil health. A combine designed specifically for the job must still be constructed, but we expect that it will cut the whole stalk a few inches above the soil, leaving some stalk anchored to the ground. A single-pass harvester could cut the entire plant a few inches above the ground and pull all of it, e.g., stalks, leaves, cobs, and grain into the combine, where they become a single, mixed grain and stover stream. The harvester blows the entire stream into tractor-pulled grain-carts that run along-side the harvester. When a cart is filled, it is replaced by an empty cart, and the full cart is hauled to the field side, where it's unloaded into bulk 'walking-floor' semi trailers, and hauled to a co-op or depot type elevator/facility for further processing and storage. At the elevator, the stover/grain mix is unloaded into equipment for further processing before it's sent to storage. Although a facility (equipment, buildings, etc.) at an elevator for separating the corn grain from the stover has not been constructed, we anticipate that it could operate very much like a modern grain harvester/combine, except it will obviously be stationary. The entire stream could be fed, by chain or belt, where it drops between a cylinder covered with rough steel bars and a piece of equipment called a concave. As the cobs are rubbed between the steel bars and concave, the corn grain rubs off and drops onto a perforated belt; most of the stover remains are larger than corn grain pieces, and is moved rearward toward the spreader. The corn grain and small stover particle fall through and are carried to a chaffer.

Small grain straws, such as those from wheat, oats, barley, and rice have been harvested for many years. A significant difference between the harvesting equipment used for corn stover and these grains, is that the small grain plant is cut off near the ground and passes through the combine at the time of harvest. It falls to the ground from the harvester into somewhat of a windrow; in some cases, the windrow many need to be raked together before baling to gain maximum removal efficiency. Since the whole grain plant had dried prior to harvest, it's not necessary to wait for the straw to dry before it's baled. Small grain straws can be baled, hauled, and stacked in standard small bales or in larger 3' x 4' x 8' square bales with current hay equipment.

Sugarcane bagasse is not harvested, in the sense we've discussed 'a harvest.' It is a byproduct of sugar production from sugarcane, delivered by truck and trailer from the sugar processing facility to the ethanol plant. If sugarcane bagasse were to be used as a cellulosic feedstock the only additional step that would be required would be to transport the bagasse from the sugar fermentation facility to the cellulosic biofuel production facility if they are not co-located.

### 1.3.1.4 Energy Crop Harvest

Energy crops are another very large potential, yet currently unutilized, source of cellulosic feedstock. As with corn stover, no harvesting process for energy crops currently exists. Additionally, the harvesting process used for energy crops will vary greatly depending on whether the energy crop is herbaceous, such as switchgrass or miscanthus, or woody, such as hybrid poplar. Nevertheless, we believe that the harvesting practices for energy crops will resemble those currently used for small grains and tree plantations respectively.

*Herbaceous Energy Crops*

The harvesting process for herbaceous energy crops, such as switchgrass and miscanthus, is expected to closely resemble that described for corn stover in the preceding section. When the herbaceous energy crops are sufficiently dry they will be cut with a mower or swather, similar to those used to harvest hay, and left on the field in windrows. The energy crops will then be baled and moved to the roadside where they will await transportation to a storage location.

While it is possible to harvest herbaceous energy crops using currently available equipment designed for hay and other agricultural residues, the high yields of these crops present several challenges. The higher production rates per acre of energy crops, when compared to hay or corn stover, will require unique equipment designs. There is also likely to be a small harvest window where the crop is ready to be harvested, but before the onset of winter weather, especially in northern parts of the country. As more energy crops are grown and harvested as feedstocks for biofuels and energy sources in other sectors, it is likely that harvesting equipment will be developed that is optimized for energy crops.

There may also be significant regional variation in the harvesting process for energy crops. Energy crops grown in the south will have a longer harvest window, as winter weather arrives at a later date, and in many cases is not severe enough to halt harvesting operations. Longer growing seasons in the south may also enable multiple harvests in the same year to further increase yields. Finally, in parts of the country where year round harvest is possible energy crops may be able to be harvested on an as needed basis, negating the need for secondary storage and significantly reducing the delivered cost of the energy crops to the biofuel producers. For more information on cellulosic feedstock storage and it's impact on feedstock price see sections 1.3.2 and 4.1.1.2.

*Woody Energy Crops*

As with herbaceous energy crops, it is possible to harvest woody energy crops with equipment currently in use by logging operations and the pulp and paper industry. Trees can be cut and gathered using a feller buncher and then transported to the roadside. Once at the roadside they can either be chipped and blown into chip vans for transportation to the biofuel production facility, or bundled using the process described above in the forest residue section. It is more likely, however, that woody energy crops will be harvested using equipment specifically designed for that purpose and able to take advantage of the regular spacing of the trees found on tree plantations. In Europe self propelled harvesters that cut and chip the woody energy crops are being used. The wood chips are then stored in large stacks until they are transported to the facility where they will be used[190]. Work is also being done in Canada to design a harvester capable of cutting, shredding, and baling woody energy crops. These bales would then be transported to a storage area and allowed to dry before being chipped and used for biofuel production. We anticipate that woody energy crops will be harvested using a process optimized to fit the individual woody energy crop plantation, likely resembling one of the processes just described.

### 1.3.2 Feedstock Transportation and Storage

Once cellulosic feedstocks have been made available at the roadside, either through collection or harvesting, they must then be transported to the biofuel production facility. For some feedstocks, such as sorted MSW, this may be as simple as delivering the feedstock to a biofuel production facility rather than a landfill. For other feedstocks, such as agricultural residue or energy crops, it will require a much more complicated process involving multiple relocations, loadings, and unloadings, as well as storage in a secondary storage facility. The complexity of the transportation of the feedstock from the location where it is produced to the biofuel production facility is most dependent on whether the feedstock is available year round and harvested on an as needed basis or collected or harvested on an annual or semi-annual basis.

#### 1.3.2.1 Secondary Storage

One potential challenge for cellulosic biofuel producers is where the cellulosic material will be stored before it is converted into fuel. Some feedstocks, such as MSW or wood residues, can be collected or harvested year round. It will therefore only be necessary for the biofuel production facility to store a small amount of feedstock on site, we estimate 3-4 days worth, and additional feedstock can be received regularly directly from the producers. Agricultural residues and herbaceous energy crops, however, are harvested annually or semi-annually, and therefore the biofuel producer must be able to store a years worth of feedstock. Because of the low energy density of cellulosic feedstocks it would not be feasible to store a years worth of feedstock at the biofuel production site, as this would require an area of several hundred acres for feedstock storage alone at larger facilities.

One method that has been suggested is storing baled feedstock at the roadside on the farms where it is produced. It would then be loaded onto trucks and transported to the biofuel production facility as needed. This method of cellulosic storage at the farms where it is produced would be problematic. Storing significant quantities of feedstock at the farm sites could force land that would otherwise be used for feedstock production to be instead used for feedstock storage. Heavy traffic by the bale loaders and trucks used for transportation could cause significant damage to the farmers' fields. Finally, because access to these feedstocks would often be over unimproved private roads on the farmers land there is a real risk that feedstock supply could be interrupted by extended periods of inclement weather. We believe that the combination of these factors makes feedstock storage at the site where it is produced unlikely.

Another storage option would be to use secondary storage sites. In this method of feedstock storage baled cellulosic feedstock would be moved from the site of production to a secondary storage facility at the time of harvest. It would then be transported from the secondary storage site to the biofuel production facility as needed. Feedstock from many farms would be collected at a single secondary storage site. The number of secondary storage sites would depend on the size of the biofuel production plant and the density of the feedstock production. Storing cellulosic feedstock in secondary storage sites increases the delivered cost of the feedstock, but could be necessary due to the limitations of on farm storage mentioned above.

In addition to where the cellulosic feedstock is stored, there is also the question of how the feedstock will be stored. Many different ways of storing the feedstock have been suggested, ranging from stacked bales exposed to the weather, to bales wrapped in plastic, to storage in covered buildings or pole barns. The issue of whether the feedstock should be baled as round or square bales also effects how the feedstock should be stored. Round bales store better in the open than square bales since rain, and particularly snow, collect on flat surfaces more readily than on round. When stacked, however, round bales usually cannot be stacked more than three bales high without the risk of deformation, instability of the stack, and dry matter loss. Square bales, however, can be stacked as many as five high without the risk of instability.

In making the decision whether to store the bales in an indoor facility the cost of the storage facility must be weighed against the dry matter loss that will result from storing the bales in the open. Dry stover bales stored indoors or outdoors had average dry matter losses of 5% and 15%, respectively. Wrapping dry bales in net or plastic wrap and storing on a well drained surface significantly reduced dry matter loss compared to storing twine wrapped dry bales on the ground.[191] Wrapping bales in net of plastic, however, is usually done at the time of bailing at the farm site, and it is not clear whether it is feasible to transport and stack wrapped bales at a secondary storage site. Indoor storage is, in most cases, a concrete slab with a roof, supported by poles, with open sides (pole-barn). Depending on the number of bales to be stored, the slab must be sized to include aprons around all four edges with aisles between stacks to accommodate stacking and hauling equipment and for fire safety. Considering these many factors, we believe that indoor storage is the storage method that will be most widely utilized. This is the storage method which was used in our cost analysis, which can been seen in more detail in Section 4.1.1.

#### 1.3.2.2 Municipal Solid Waste (MSW) Transportation

Transportation and storage of MSW as a feedstock is relatively simple. If the biofuel producer is using MSW that has already been separated, all that would be required would be to transport the feedstock from the facility where it is separated, most likely a recycling center, to the biofuel production facility. This would be done in large over-the-road trucks. The biofuel producer would have to store several days worth of feedstock at the fuel production site to ensure that fuel production is not interrupted, but because MSW is produced and collected year round no secondary storage would be necessary.

If the biofuel producer is receiving unsorted MSW it is probable that the sorting facility would be co-located with the biofuel production facility. If the biofuel production facility is near the source of MSW it may be possible for the local refuse collection trucks to deliver the MSW to the plant directly. If the biofuel production facility is located some distance from the MSW source it will be more cost effective to transfer the MSW from local refuse collection trucks to large over-the-road trucks for transportation to the biofuel production facility. Once again, no secondary storage would be required due to the consistent availability of MSW. In this case, however, the biofuel producer would have to arrange for the transportation of recovered recyclable materials, as well as contaminated waste that cannot be used to produce biofuels.

#### 1.3.2.3 Wood Residue Transportation

Wood residues are expected to be collected from the places they are produced, the primary or secondary mill for mill residues and the roadside of the forestry operation for forest residue and forest thinnings, and transported directly to the biofuel production facility in large over-the-road trucks. For each of the three types of wood residues we expect that the wood will be chipped or processed in some other way to increase the density of the residue before transportation. This will reduce transportation costs by allowing a greater mass of wood residue to be transported by each truck. As with MSW, secondary storage is unlikely to be necessary for wood residues as they are available to be harvested throughout the year.

#### 1.3.2.4 Agricultural Residue and Energy Crop Transportation and Storage

Unlike MSW and wood residues, which are available to be harvested and collected throughout the course of the year, agricultural residues and herbaceous energy crops are harvested on an annual or semi-annual basis. As a result, a large amount of feedstock, enough to supply the biofuel production facility for a whole year, must be stored and delivered throughout the year. We expect secondary storage sites, as described above, will be the best option. Following the baling operation, the bales of agricultural residue or energy crops will be picked up from the field in 10-bale loads, by vehicles designed for that purpose. Such vehicles are currently used to gather hay bales today. The bales are subsequently unloaded or dropped at the field-edge. Later, the bales are loaded onto wagons pulled by high-speed tractors that haul as many as 20-bales per load to satellite storage (the pole-barns described in Section 1.3.2.1). The bales are unloaded and stacked for storage until they are needed at the ethanol plant. Transport to the plant is by over-the-road trucks and trailers that can haul net-loads of up to about 45- to 50-tons. However, because the bale density is low (on average, about half the weight of a similarly sized hay bale), the maximum number of bales a truck can haul usually weighs much less than the maximum allowable weight. Grinding the baled feedstock before transportation to the biofuel production facility would increase the density of the feedstock, and therefore increase the mass that each truck could transport and lower the overall transportation costs.

As discussed in Section 1.3.1.2, we anticipate that the corn stover harvest could become a single-pass operation by 2022. In this case corn stover would be transported from the farm to a specialized cellulosic feedstock depot to be processed. Equipment at the cellulosic feedstock depot would chop and dry the corn stover. This distributed preprocessing facility can provide significant cost benefits by producing a higher value cellulosic feedstock with improved handling, transporting, and merchandising potential. In addition, data supporting the preferential deconstruction of feedstock materials due to their bio-composite structure identifies the potential for significant improvements in equipment efficiencies and compositional quality upgrades.[192] The stover, now with flowability characteristics similar to small cereal grains, is moved by standard grain loading and unloading systems into large corrugated steel bins for intermediate storage. In this harvest format, the stover is handled by only two machines before it reaches the roadside and never hits the ground, significantly reducing dry matter losses. The biofuel producer would then pick up its feedstock from the elevator/depot in trucks and trailers for transport to the facility. We believe stover feedstock in the ground format could have a significantly higher bulk-density than baled stover, which should translate into lower transportation costs.

### 1.3.3 Cellulosic Feedstock Transportation and Storage Tool

In order to better estimate the impacts of transport and secondary storage on the overall price of cellulosic ethanol, we have developed a tool that estimates the location of future cellulosic ethanol plants. Using these locations, we can estimate the average cost for transport of feedstock material both locally (within the plant-containing county) as well as imported from other areas in the country. The tool also provides us an estimate of the type of feedstock material used by each plant, allowing us to determine the average cost of secondary storage for these materials.

#### 1.3.3.1 Basis and Assumptions for Transport Tool

Feedstock densities and locations have been compiled on a county basis for use within the tool. This information has been provided by a variety of sources, including the National Forestry Service for forestry residue, the National Agricultural Statistical Service (NASS, 2007) for agricultural residues and Elliot Campbell from Stanford University for energy crops. Municipal solid waste is also considered for this tool. For more information regarding the sources of data used for the tool, see Section 1.1.2 of this RIA. Data for agricultural residues provided by NASS reported harvested grain values, and needed to be modified to reflect agricultural residue values, using grain to residue ratios[193]. Data provided from FASOM modeling was used in this tool for total feedstock usage as well as farmside cost.

In order to simplify the location of plants within the tool, we have assumed that plants will be constructed at a county centroid. Therefore, transport within a county to a plant is based on the transport of feedstock material from farmside to the county centroid, with consideration for feedstock density within the county as well as the total county area. Furthermore, transport of feedstock between counties (for plants importing feedstock outside the county they are located in) is based on the distance between county centroid locations, with an additional factor to account for the added distance of using on-road transportation. Information regarding the costs of this transportation can be found in Section 4.1.1.2 of this RIA.

Assumptions for secondary storage used in the tool closely follow the determinations made in Section 1.3.2 above. Secondary storage costs in the tool are based on the amount of feedstock to be stored, the density of the feedstock being stored, as well as the type of feedstock itself. As discussed in Section 1.3.2, the tool assumes that no secondary storage is necessary for either municipal solid waste, which would be transported to the plant directly by waste removal services; or for forest residue, which can be harvested year-round and transported on as-needed to the plant. Capital costs used in the tool for plant selection are based on current refinery modeling, broken down by PADD location. These capital costs are based on the total production volume of the plant and the PADD that it is located within. For more information on transport, secondary storage, and capital costs, please refer to Section 4.1.1.2 in this RIA.

### 1.3.3.2 Transport Tool Operation

The tool begins operation by compiling feedstock availability (by county) based on the data sources discussed in Section 1.3.3.1. Using county locations, it builds a list for each county that contains the locations of other counties within a set maximum range (these other counties will be referred to as neighbors for the remainder of this section). This list will serve as the basis for county to county feedstock transport further on in the tool operation. The tool then adds feedstock information such as feedstock densities, total amount of feedstock available, and feedstock type specific to each county. Using this feedstock information, the tool generates a list of all feedstocks available for each county; both within the county itself as well as feedstock available for import from other neighboring counties. At the end of this step in the tool operation, each county has a datapoint in the tool which contains a complete list of all feedstock available to that location.

Using the list of feedstocks available to each county generated in the last step, as well as the transportation and secondary storage cost assumptions discussed in Section 1.3.3.1, the tool calculates and adds complete cost information for each feedstock available to a county. These costs include the farmside cost of the feedstock, the transportation required to move the feedstock to the centroid of its own county and the secondary storage of that feedstock. If the feedstock is available by import from a neighboring county, the transportation cost of moving that feedstock from the neighboring county is also added to the complete feedstock cost for that source. At the end of this step in the tool operation, each county datapoint contains a list detailing the total cost of each feedstock available as they would be delivered to that county.

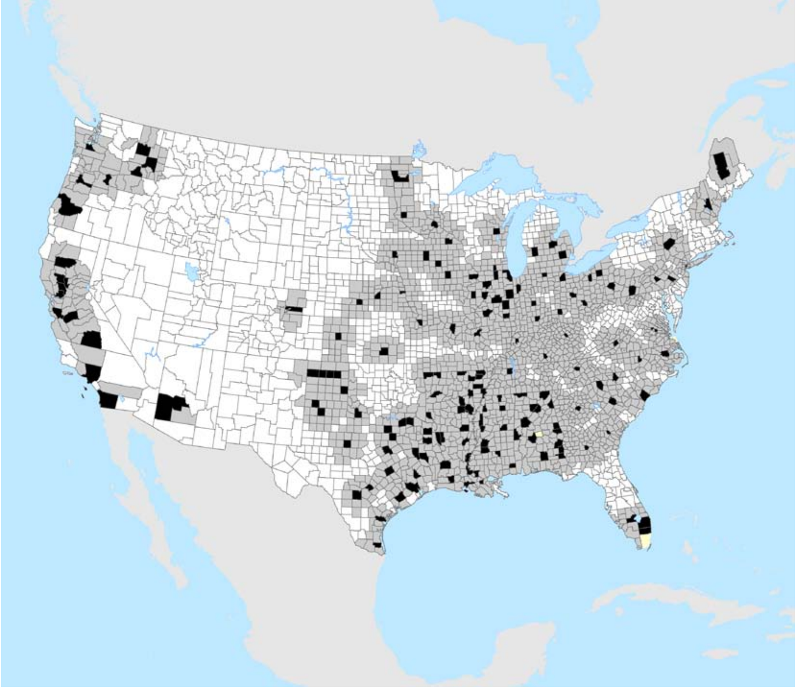
In the next step of the tool operation, the list of feedstock availability cost is used to choose feedstocks that a plant located at each county centroid would processes. For each county, the cheapest feedstock from the list is selected for the plant. The volume of feedstock available at this price is then converted to gallons (based on feedstock conversion modeled by FASOM) and added to a running count of the total volume of feedstock processed by that county. Capital costs associated with the increased volume are also added to the total cost of the feedstock processing for that county. The tool continues adding feedstock sources to a county by selecting the next cheapest feedstock on the list. Selection proceeds until either the county either reaches a set maximum processing volume, or when adding another feedstock would produce a result more expensive on a price per gallon basis. At the end of this step, each county datapoint contains information regarding the cheapest total cost to produce cellulosic ethanol at that location.

The tool proceeds by scanning the entire list of county locations for the cheapest processing location that could be constructed. This location is added as an estimated cellulosic ethanol plant location for the final output of the tool. The feedstock used in by location is removed as a source from any feedstock availability list used by other counties. The tool then repeats using this modified feedstock data, starting from the step involving the selection of feedstocks used in a county. In this way, a list of estimated plant locations is chosen by always selecting the next cheapest location in which a plant can be built; this provides the final output of the tool. The tool stops operation when the total processed volume of all locations selected reaches the sixteen billion gallon maximum discussed in Section 1.3.3.1.

#### 1.3.3.3 Final Tool Output and Interpretation

Not only does the tool provide estimated plant locations, it also provides supplementary information we have used to estimate average transportation and storage costs for feedstocks used by each plant, and subsequently all plants estimated by the tool. Since both the farmside feedstock cost as well as the contribution of capital cost is known for each of the estimated plants (as these are inputs to the tool), the transportation and storage costs can be calculated for each ton of feedstock processed by that plant, including county to county transport. The cost of transportation for each plant can then be averaged with the other plants selected by the tool to arrive at a total transportation and storage cost average across all plants selected by the tool. For more information about how these transportation and storage costs are used, see Section 4.1.2 in this RIA.

**Figure 1.3-1**
**Illustration of Estimated Plant Sites Selected by Plant Siting Tool**



*Counties in black show active plant locations, counties in grey show active feedstock use*

In Figure 1.3-1 above, an illustration of the plant locations selected by the tool can be seen. It is important to note that the above average number of plants selected for the southern region of the United States is most likely due to the lower capital costs associated within the this region. The tool takes into account regional variations of plant construction and operation costs. The lower capital cost in the southern region (most likely due to existing construction infrastructure for conventional oil refineries) reduces the overall price of plants selected in these locations, and we feel explains why the tool has a preference for this region of the country. More specific information on these capital cost regions can be found in Section 4.1.1.2 of this RIA.

The tool was run multiple times using differing values for total feedstock availabilities as well as the percentage of feedstock associated with each type. We have selected the tool output that most closely matches the output for feedstock usage provided by the FASOM model, as we feel that it is important to keep the feedstock usage quantities consistent across our analyses. However, as improved input factors and estimates are developed over time, the tool can be easily adjusted and updated to take into account this new information.

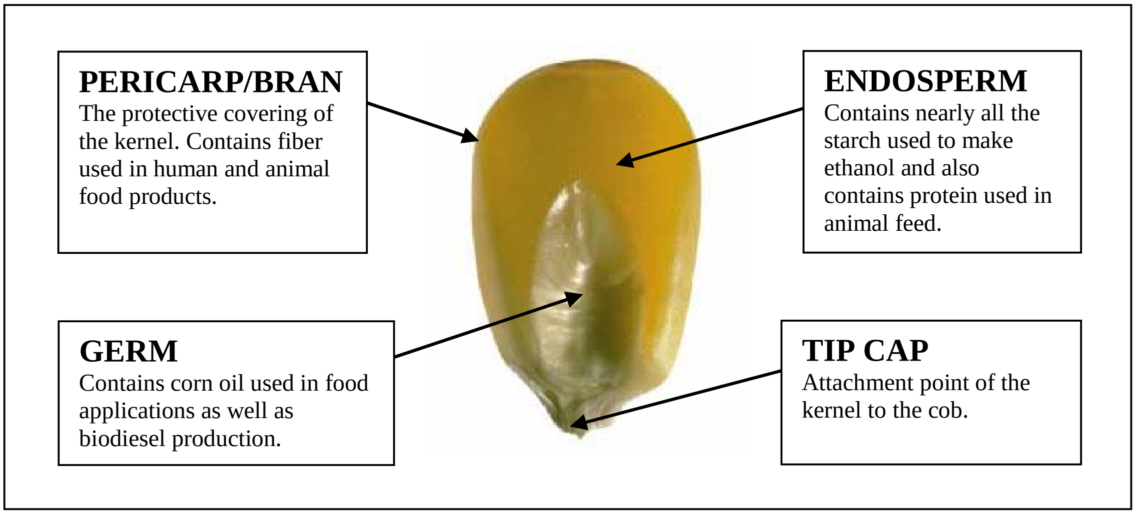
## 1.4 Biofuel Production Technologies

Biofuel production technologies continue to evolve with research and development efforts focused on reducing costs and increasing efficiencies. Improvements include increasing conversion yields for various feedstocks, reducing energy and materials usage, eliminating or reducing wastes, finding alternative uses for by-products, etc. For those technologies not yet commercial, researchers are combining their innovative ideas to develop cost-effective processes to produce biofuel at low enough costs to compete with their petroleum counterparts. The following sections describe both proven and new technologies which may be used to produce renewable fuels to meet the EISA 36 billion gallon standard by 2022.

### 1.4.1 Corn Ethanol

There are two primary processes for converting corn (and other similarly processed grains) into ethanol: wet milling and dry milling. The main difference between the two is in the treatment of the grain. Dry mill plants grind the entire kernel (shown below in Figure 1.4-1) and generally produce only one primary co-product: distillers grains with solubles (DGS). The co-product is sold wet (WDGS) or dried (DDGS) to the agricultural market as animal feed. Wet mill ethanol plants separate the grain kernel prior to processing into its component parts and produce other co-products (usually gluten feed, gluten meal, and food-grade corn oil) in addition to DGS. Each process is described in greater detail in the subsections that follow.

**Figure 1.4-1. Components of the Corn Kernel**



**PERICARP/BRAN**
The protective covering of the kernel. Contains fiber used in human and animal food products.

**ENDOSPERM**
Contains nearly all the starch used to make ethanol and also contains protein used in animal feed.

**GERM**
Contains corn oil used in food applications as well as biodiesel production.

**TIP CAP**
Attachment point of the kernel to the cob.

#### 1.4.1.1 Dry Milling Technology[194]

In traditional dry mill plants, first the corn is screened to remove any unwanted debris. Then, it goes through a hammer mill where it is ground into course flour also know as “meal.” Next the meal is cooked to physically and chemically prepare the starch for fermentation.

The first step of the cooking process is to form a hot slurry. The meal is mixed with water, the pH is adjusted, and an alpha-amylase enzyme is added. The slurry is heated to 180–190°F for about 30–45 minutes to reduce viscosity.

The second step in the cooking process is liquefaction, which occurs in two steps. First the hot slurry is pumped through a pressurized jet cooker at approximately 220°F and held for about 5 minutes. The mixture is then cooled by an atmospheric or vacuum flash condenser. After cooling, the mixture is held for 1–2 hours at 180–190°F to give the alpha-amylase enzyme time to break down the starch into short-chain carbohydrates also know as “dextrins.” Once cooking is complete, a pH and temperature adjustment is made, a second enzyme (glucoamylase) is added, and the resulting mixture (also know as “mash”) is pumped into the fermentation tanks.

During the fermentation process, the glucoamylase enzyme breaks down the dextrins to form simple sugars. Yeast is added to convert the sugar into ethanol and carbon dioxide. The mash is then allowed to ferment for 50–60 hours. The result is a mixture that contains 10-15% ethanol by volume (20 to 30-proof) as well as solids from the grain and added yeast.

From here, the fermented mash is pumped into a multi-column distillation system where additional heat is added. The columns utilize the differences in the boiling points of ethanol and water to boil off and separate the ethanol. By the time the product stream leaves the distillation columns, it contains about 95% ethanol by volume (190-proof). The residue from this process, called stillage, contains non-fermentable solids and water and is pumped out from the bottom of the columns into the centrifuges.

The final step in the ethanol production process is dehydration to remove the remaining 5% water. The ethanol is passed through a molecular sieve to physically separate the water from the ethanol based on the different sizes of the molecules. The result is 200-proof anhydrous (waterless) ethanol. At this point, a denaturant, which typically is natural gas liquids, is added (making it unfit for human consumption) and the ethanol is placed into storage.

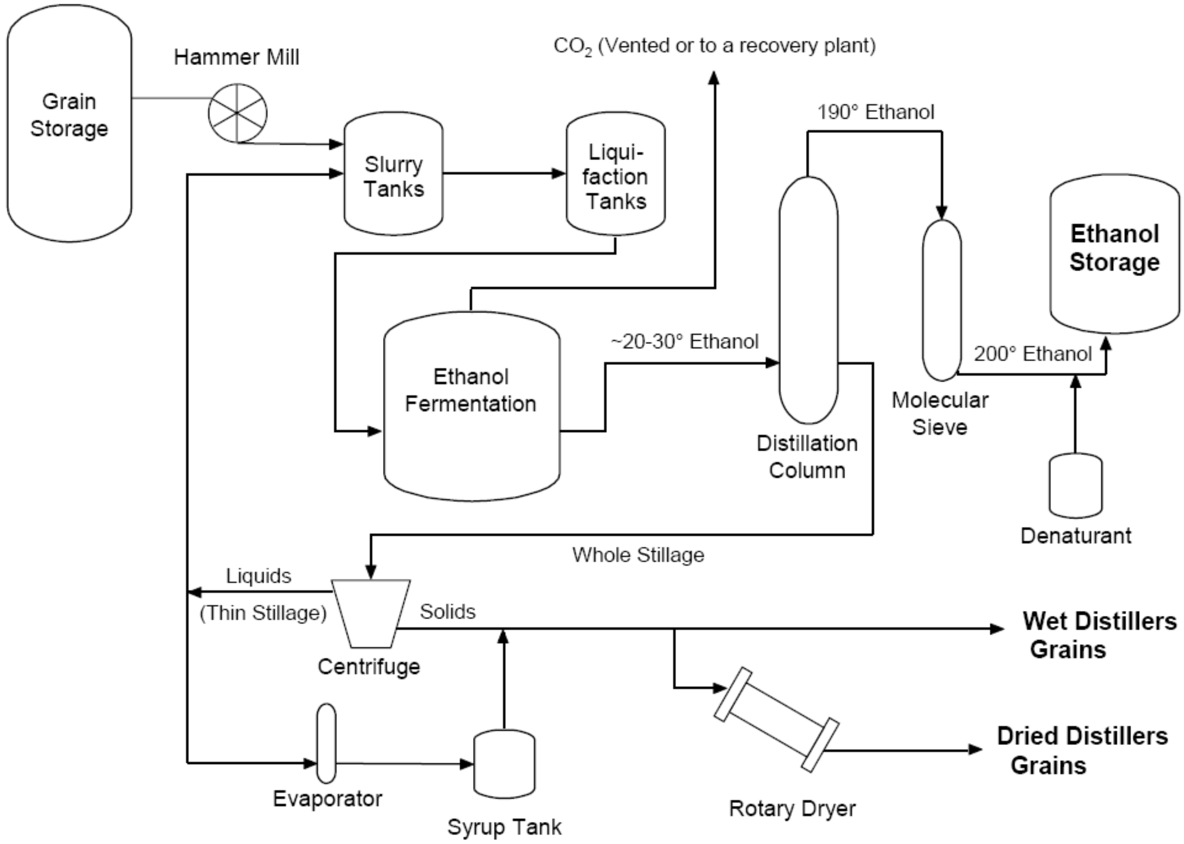
During the ethanol production process, two primary co-products are created: carbon dioxide and distillers grains. As yeast ferment the sugar, they release large amounts of carbon dioxide gas. In some plants it’s released into the atmosphere, but where local markets exist, it’s captured and purified with a scrubber and sold to the food processing industry for use in carbonated beverages and flash-freezing applications.

The stillage from the bottom of the distillation columns contains solids from the grain and added yeast as well as liquid from the water added during the process. It is separated via centrifuge into thin stillage (a liquid with 5–10% solids) and wet distillers grain.

Some of the thin stillage is routed back to the cooking tanks as makeup or “backset” water, reducing the amount of fresh water required by the cooking process. The rest is sent through a multiple-effect evaporation system where it is concentrated into a condensed distillers solubles or “syrup” containing 25–50% solids. This syrup, which is high in protein and fat content, is then mixed back in with the distillers grain to make wet distillers grains with solubles.

Wet distillers grains with solubles (WDGS) contain most of the nutritive value of the original feedstock (plus added yeast) and can be easily conveyed as a wet cake for transport. As such, WDGS makes an excellent cattle ration for local feedlots and dairies. However, WDGS must be used soon after it’s produced because the wet grains spoil easily. Since many ethanol plants are located in areas where there are not enough nearby cattle to utilize all the feed, a portion or all of the WDGS is sent through a drying system to remove moisture and extend the shelf life. The resulting dried distillers grains with solubles (DDGS) are commonly used as a high-protein ingredient in cattle, swine, poultry, and fish diets. Distillers grains are also being researched for human consumption. A schematic of a typical dry-mill ethanol plant is shown below in Figure 1.4-2.

**Figure 1.4-2. Dry Milling Process**



### 1.4.1.2 Wet Milling Technology[195]

In wet mill plants, first the corn is soaked or "steeped" in a dilute sulfurous acid solution for 24-48 hours. The steeping process facilitates the separation of the corn kernel into germ, fiber, gluten, and starch.

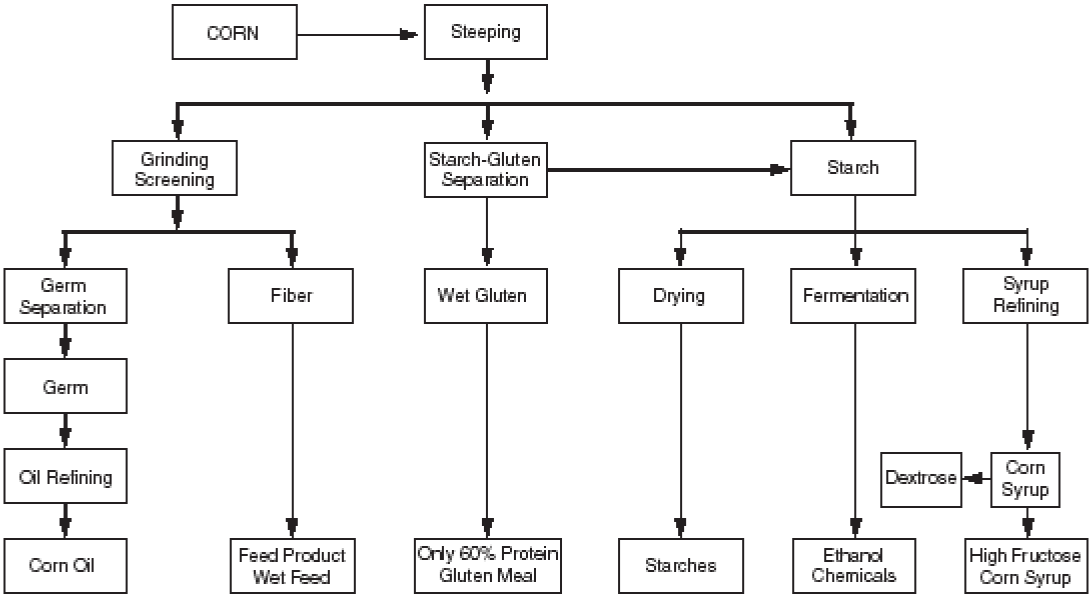
After steeping, the corn slurry is processed through a series of grinders to separate out the germ. The germ is either extracted on-site or sold to crushers who extract the corn oil. The corn oil in its crude state can be sold to the biodiesel or renewable diesel industry. However, most wet mill plants refine the product into food-grade corn oil for use in cooking applications. The remaining fiber, gluten and starch components are further segregated using centrifugal, screen, and hydroclonic separators.

The steeping liquor is concentrated in an evaporator. This concentrated product, heavy steep water, is co-dried with the fiber component and is then sold as corn gluten feed to the livestock industry. Heavy steep water is also sold by itself as a feed ingredient and is used as a component in Ice Ban, an environmentally-friendly alternative to salt for removing ice from roads.

The gluten component (protein) is filtered and dried to produce the corn gluten meal co-product. This product is highly sought after as a feed ingredient in poultry broiler operations.

The starch and any remaining water from the mash is generally processed in one of three ways: fermented into ethanol, dried and sold as dried or modified corn starch, or processed into corn syrup. If made into ethanol, the fermentation process is very similar to the dry mill ethanol production process described above. A schematic of the wet milling process is shown below in Figure 1.4-3.

**Figure 1.4-3. Wet Milling Process**



### 1.4.1.3 Advanced Technologies

A number of corn ethanol plants are exploring new technologies with the potential to increase their profits by producing higher value co-products and reducing the ethanol plants energy requirements. Dry fractionation and corn oil extraction seek to recover the oil in the corn kernel for sale in the food, feed, or biodiesel markets. Cold starch fermentation and membranes that reduce ethanol distillation energy requirements are two of several new technologies focusing on reducing the energy usage of ethanol production facilities. Finally a growing number of companies are utilizing alternative boiler fuels and/or incorporating combined heat and power (CHP) technology into their facilities to reduce to plant energy requirements, and in some cases, produce excess power for the grid. The advanced technologies currently being pursed by the corn ethanol industry are described in more detail below.

### *Dry Fractionation*

Dry fractionation is a mechanical separation of the corn kernel into its three component pieces, the germ, bran, and endosperm before fermentation. This separation decreases the amount of non-fermentable material sent through the process and allows each of the components to be processed separately to produce new, higher-value co-products. As shown in Figure 1.4-1, the germ is the small, non-fermentable part of the kernel consisting primarily of protein and oil. Food grade corn oil can be extracted from the germ. After the oil has been extracted, the remainder of the germ can then be blended into the DGS to increase its protein content. The bran, or pericarp, is the protective outer covering of the kernel. The bran can be sold as cattle feed, human fiber additive, or corn fiber. It can also be burned to reduce the amount of coal or natural gas required for ethanol production. The endosperm, which contains approximately 98% of the starch, and is the only fermentable portion of the kernel, is sent to the fermentation vessels. Decreasing the amount of non-fermentable materials (germ and bran) in the process has many beneficial effects, including increasing the production capacity of the plant, decreasing the energy required to dry the DGS, and potentially decreasing the enzyme requirement of the plant by up to 30%.

While the production capacity of the plant increases with the addition of dry fractionation, the amount of corn used to produce a gallon of ethanol increases by approximately 2-3% due to starch loss in the fractionation process. Dry fractionation is also a capital intensive process, costing an estimated $35 million to add to an existing 100 million gallon per year ethanol plant. Dry fractionation is currently able to recover 50% or more of the corn oil contained in the corn kernel. For our economic analyses we have assumed an oil recovery rate of 50% for ethanol plants that use dry fractionation. Several companies, including ICM, Delta-T, and POET currently offer dry fractionation options for new or existing plants.

### *Corn Oil Extraction*[196]

An alternative method to recovering the oil contained in the corn kernel is corn oil extraction. Corn oil extraction is a method of mechanical separation, often by centrifuge, used to extract the crude corn oil from the thin stillage (the non-ethanol liquid left after fermentation), the DGS before it has been dried, or a combination of both. While the corn oil is of a lower quality and value than that produced from corn fractionation, the equipment can be easily added to existing ethanol production facilities and is relatively inexpensive. We estimate that adding corn oil extraction equipment to an existing 100 million gallon per year corn ethanol plant would cost between $5 million and $12 million, depending on the type of equipment used and the percentage of oil recovered. The starch losses associated with dry fractionation do not occur with corn oil extraction as the whole kernel still goes through the fermentation process. The gains in plant capacity and reduced enzyme usage of the dry fractionation process are similarly not realized.

The oil recovered using the corn oil extraction process is distressed oil and cannot be sold as a food grade product. Markets for this product do exist, however, as an additive to cattle feed or as a biodiesel feedstock. In addition to generating an additional revenue stream, extracting the corn oil has several other benefits for the ethanol producer. Because the oil is an insulator, removing it improves the heating efficiency of the DGS dryers and reduces the energy demand of the ethanol plant. Reducing the oil content of the DGS also improves its flowability and concentrates its protein content. The de-fatted DGS is potentially more marketable than DGS containing corn oil, as higher quantities may be able to be included in the diets of poultry and swine. Several ethanol producers are currently using corn oil extraction technology and have reported oil recovery rates of greater than 33%. Technology providers have indicated that in the near future they expect to be able to extract up to 75% of the oil contained in the kernel. For our economic analyses we have assumed that by 2022 ethanol production plants using oil extraction technology will be able to extract 66% of the oil in the corn.

### *Cold Starch Fermentation*[197][198]

POET Biorefining, the United States' largest corn ethanol producer[W], has developed a cold starch fermentation process that uses raw-starch hydrolysis to convert starch to sugar, which then ferments to ethanol without heat. The patent-pending POET technology eliminates the cooking process that has been part of ethanol production for years. According to POET, the BPX™ process not only reduces energy costs, but also releases additional starch for conversion to ethanol, increases protein content and quality of co-products, increases co-product flowability, potentially increases plant throughput, and significantly decreases plant emissions. The benefits of the process include reduced energy costs, increased ethanol yields, increased nutrient quality in the distillers grains and decreased plant emissions. At least 20 POET plants currently utilize the BPX™ cold starch fermentation technology. According to POET, the BPX™ process, which yields 20% ethanol in fermentation, increases theoretical ethanol yields from the industry standard of 2.7 gallons of ethanol per bushel of corn up to 3 gallons per bushel. POET also recently announced that it was funding a research collaboration with Iowa State University to help improve the efficiency of the BPX™ process.

As with any new process there are several potential drawbacks to cold starch fermentation. Because heat is not used to aid in the hydrolysis of starch, more enzymes may be required. These additional enzymes may cost the ethanol producer more than $500,000 per year for a 100 million gallon per year plant. An additional benefit of the cooking process is that it sterilizes the starch slurry before fermentation, killing microorganisms and neutralizing toxins that are often contained in the corn. Without this step, the microorganisms may compete with the yeast, lowering ethanol yields. Toxins may pass through the process to the DGS and cause problems with the animals that eat it. One way to minimize these problems is to treat the starch slurry with antibiotics, however recently this practice has been criticized for contributing to antibiotic tolerant or resistant bacteria. Any ethanol producer considering using cold starch fermentation must first determine whether the potential gains in ethanol yields and energy savings outweigh these risks.

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[W] At the time of our November 2009 plant assessment. For more information, refer to Section 1.5.1.1.

### *Membrane Replacement*

Several companies are currently working to produce commercially viable polymeric membranes that could potentially reduce the energy used in distillation and eliminate the need for molecular sieve units currently used in most ethanol plants. One such company, Vaperma, has partnered with GreenField Ethanol to prove the viability of its Siftek$^{TM}$ technology. Siftek$^{TM}$ membranes have been successfully installed in GreenField's Tiverton, Ontario demonstration plant and are scheduled to be installed in their Chatham, Ontario plant, which produces 187 million liters of ethanol per year, by the end of 2008. Vaperma claims its Siftek$^{TM}$ membranes are capable of producing a fuel grade ethanol product from an ethanol/water mixture that contains as much as 60% water. These membranes would replace the rectifier unit as well as the molecular sieves used in a conventional ethanol plant, potentially reducing the energy consumption of the ethanol dehydration process by up to 50%. Another way for these membranes to be used is to treat the ethanol/water vapor collected when the molecular sieve units are regenerated. This stream is usually recycled to the rectifier and makes up approximately one third of the feed to the rectifying column. Using Siftek$^{TM}$ technology to treat this stream reduces the feed to the rectifier, reducing energy consumption and increasing production rate by 20% or more. While membrane replacement technology has the potential to significantly reduce the energy demands of an ethanol plant, they are likely at least a couple of years from being commercially available. It is not expected that membrane replacement units would be retrofitted into existing plants due to the significant capital costs. These two factors will effectively limit the use of membrane separation units to new ethanol plants built in 2010 or later.

An alternative method of membrane replacement is to use ethanol-permeating membranes to eliminate the need for the beer column, followed by a water-selective membrane for final dehydration. Eliminating the need for the beer column as well as the rectifier and molecular sieve units would significantly reduce the capital costs of an ethanol plant, as well as lowering the energy requirements of ethanol separation. While this technology has the potential to significantly lower the cost and energy demands of an ethanol plant, it is highly unlikely that it will be available for near term commercialization. It has therefore not been considered section 1.5.1.3 on the forecasted growth of advanced ethanol technologies.

### *Combined Heat and Power*[199]

Ethanol production is a relatively resource-intensive process that requires the use of water, electricity, and steam. In most cases, water and electricity are purchased from the municipality and steam is produced on-site using boilers fired by natural gas, coal, or in some cases, alternative fuels (described in more detail below).[X] However a growing number of ethanol producers are pursuing combined heat and power (CHP) technology. CHP, also known as cogeneration, is a mechanism for improving overall plant efficiency by using a single fuel to generate both power and thermal energy. The most common configuration in ethanol plants involves using the boiler to power a turbine generator unit that produces electricity, and using waste heat to make process steam. In some cases, the generator produces excess electricity that can be sold to the grid. While the thermal energy demand for an ethanol plant using CHP

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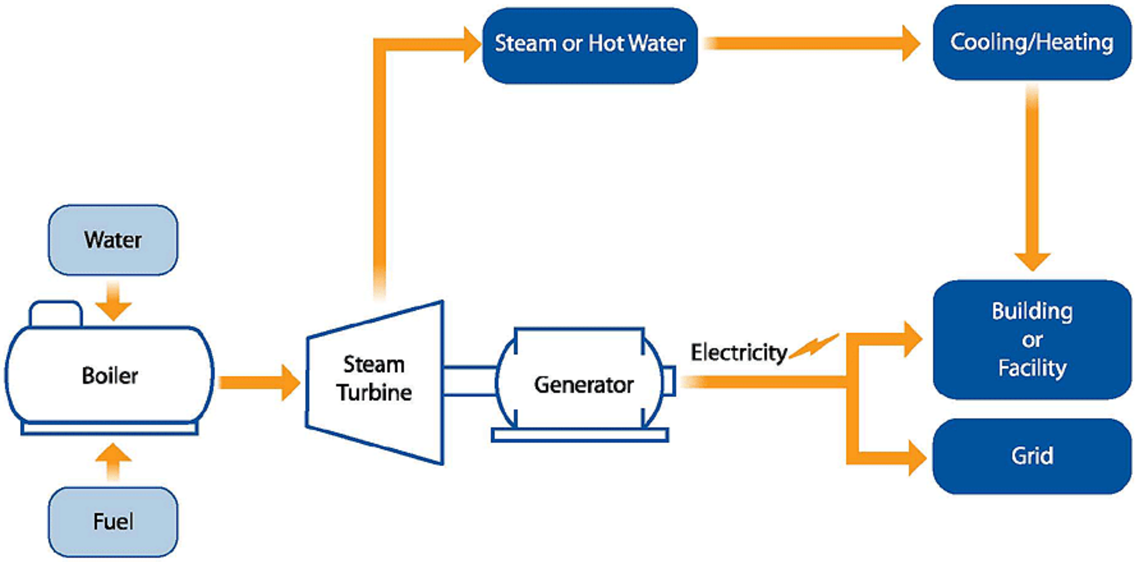
[X] Some plants pull steam directly from a nearby utility.

technology is slightly higher than that of a conventional plant, the additional energy used is far less than what would be required to produce the same amount of electricity in a central power plant. The increased efficiency is due to the ability of the ethanol plant to effectively utilize the waste heat from the electricity generation process.

The CHP system can be owned and operated solely by the ethanol plant, or jointly operated with the local utility company. In these cases it is common for the utility company to purchase the generator and to split the cost of the generator fuel with the ethanol plant. The utility company receives the electricity produced, while the ethanol plant uses the waste heat. These arrangements reduce the energy costs for both parties, as well as reducing the green house gas emissions that would be produced by operating the generator and boiler separately. An illustration of the more common CHP configuration typically seen in ethanol plants is shown below in Figure 1.4-4. Grants are available for industries looking to use CHP at both the state and national level. These grant programs will likely encourage a greater adoption of CHP among ethanol producers than would have otherwise been expected. We project that 26% of ethanol plants will use CHP in the future under the RFS2 program. For more information, refer to Section 1.5.1.3.

**Figure 1.4-4. Steam Boiler with Steam Turbine**



*Alternative Boiler Fuels*

In addition to CHP (or sometimes in combination), a growing number of ethanol producers are turning to alternative fuel sources to replace traditional boiler fuels (i.e., natural gas and coal), improve their carbon footprint, and/or become more self-sustainable. Alternative boiler fuels currently used or being pursued by the ethanol industry include biomass (wood and other organic feedstocks), co-products from the ethanol production process (bran, thin stillage or syrup), manure biogas (methane from nearby animal feedlots), and landfill gas (generated from the digestion of municipal solid waste). One potential alternative boiler fuel is biogas produced by the anaerobic digestion of the stillage in the ethanol production process. Sending the stillage to an anaerobic digester rather than drying it and selling it as DGS would produce sufficient biogas to exceed the energy requirements of the ethanol production facility. Excess methane could be sold to provide an additional revenue stream, however all revenue from DGS sales would be lost. Whether or not these systems are adopted in the future is likely to be dependent on the relative prices of electricity, natural gas, and DGS, as well as the capital costs of these systems.

For a breakdown of current and near-term[Y] utilization of CHP technology and alternative boiler fuels, refer to Sections 1.5.1.1 and 1.5.1.2. For our 2022 projections of the potential utilization of these and other advanced technologies, refer to Section 1.5.1.3.

### 1.4.2 Ethanol from Sugarcane Juice and Molasses

The production of ethanol from sugarcane juice or molasses is the least complicated method to use biomass to produce ethanol since sugarcane contains six-carbon sugars that can be directly fermented. This is currently the method used to produce ethanol in Brazil. In contrast, starch or cellulosic feedstocks require additional steps before sugars are released for use in the fermentation step.

In the production of sugarcane ethanol and sugar from sugarcane juice or molasses, the cane stalks are shredded and the juice is extracted across tandem mills or a diffuser. The juice contains most of the soluble sugars and the leftover sugarcane fiber is bagasse. Next, the cane juice is filtered then heated and limed to precipitate impurities during the clarification process. The resultant clarified juice is then concentrated across an evaporation station (14-16°Brix up to 65°Brix). The syrup produced is then further evaporated in vacuum pans and seed crystallized, leading to a mixture of sucrose crystals surrounded by molasses with a concentration of 91-93°Brix. The sugar crystals and molasses are subsequently separated by centrifugation. In ethanol production in Brazil, the sugars in the juice are fermented into ethanol by the addition of yeast. Fermentation varies from 4-12 hours, with ethanol yields ranging from 80-90%. The fermented mixture is then distilled to produce hydrous (96 % ethanol) or anhydrous ethanol (99.7 % ethanol). The production of anhydrous ethanol is done by addition of cyclohexane or by the use molecular sieves. See Figure 1.4.5 for a diagram of the sugarcane ethanol and sugar production process.[200] The production of sugar (for food and export) or ethanol depends on the supply and demand changes for both products.

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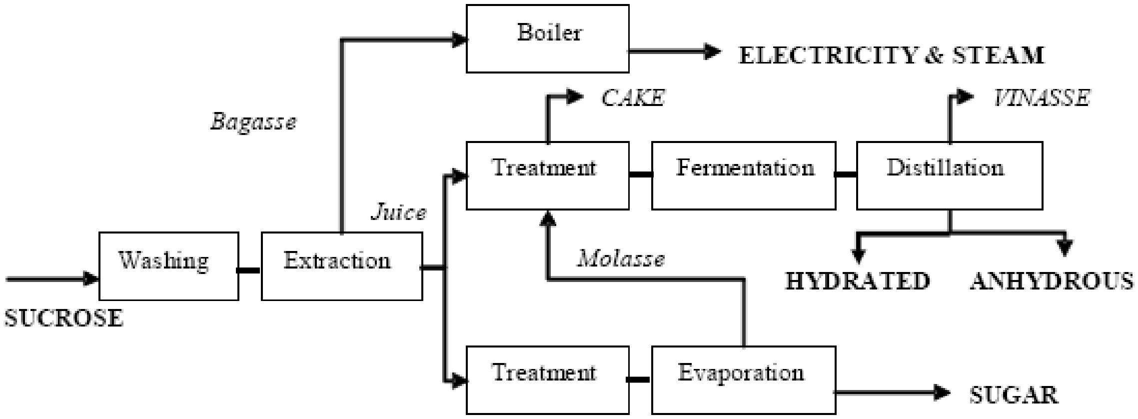
[Y] Based on current company plants.

**Figure 1.4-5. Simplified Overview of Sugarcane Ethanol and Sugar Production Process**



In addition to ethanol, sugarcane also yields trash, bagasse, filter cake mud, and vinasse. These by-products are described below:

*Trash (Leaves and Tops)*

The tops, brown and green leaves of sugarcane are commonly referred to as trash. Sugarcane trash in Brazil is not currently harvested (it is typically burned in the field); however, it is anticipated to be collected for use in the future (i.e. 2020 and beyond) since the burning of sugarcane in Brazil is being phased-out and there is an increased mechanization of harvesting sugarcane. In the U.S., sugarcane trash is currently mechanically harvested and delivered to the factory with stalks. The collection and use of trash at the sugarcane ethanol facility is beneficial as greater electricity can be produced and potentially sold to the grid.

*Bagasse*

Bagasse is the fibrous material left over after juice is extracted from the crushed stalk of the sugarcane plant. It mainly consists of hemicellulose, cellulose and lignin valued mainly for its use to produce steam for electricity. U.S. factories and other industrial units have used bagasse mainly for steam production, but a few are producing electricity (co-generation) as well. In Brazil, most facilities are able to produce more energy than needed and have exported excess electricity to the grid. This is further discussed in Chapter 2 in the lifecycle section, as surplus electricity production displaces primarily fossil-based electricity production.

*Filter Cake Mud*

Filter cake is the dried, leftover solid material from precipitated mud after sugarcane juice clarification (via lime addition) at the facility. It is sometimes reapplied to sugarcane fields as a fertilizer.

*Vinasse*

Vinasse is the liquid waste product from the ethanol distillation process. It is rich in minerals, organic material, and water. Some countries are allowed to spray vinasse on sugarcane crops as fertilizer. For instance, it is produced and used throughout the harvest in Brazil but is not allowed in the U.S. Environmental legislation prohibits inappropriate disposal of vinasse into rivers, lakes, the ocean, and soils.

### 1.4.3 Cellulosic Biofuel

The following sections contain descriptions of cellulosic ethanol and cellulosic diesel production technologies. Section 1.4.3.1 introduces the two primary pathways for the production of cellulosic ethanol, through biochemical and thermochemical processes while Section 1.4.3.2 discusses cellulosic diesel which is produced through thermochemical processes. We end the section with specific company descriptions of cellulosic biofuel technologies and briefly describe how they differ from generic process discussions.

#### 1.4.3.1 Cellulosic Ethanol

Cellulosic biomass has long been recognized as a potential source of mixed sugars for fermentation to fuel ethanol. The Germans may have been one of the earliest to try commercializing a process to produce ethanol from a cellulosic feedstock, probably from wood in the late 1890s. They used dilute acid to hydrolyze the cellulose to glucose and xylose, but were able to only produce a little less than 20 gallons per ton of feedstock; they soon improved the process enough to generate yields of around 50 gallons per ton. Eventually, two commercial-sized plants that used dilute sulfuric acid hydrolysis were constructed in the U.S. Lumber production decreased following World War I, which resulted in the closing down of cellulosic plants.[201, 202] Although corn-grain ethanol was used in the early 20th Century, especially by high-performance race cars and as an additive to raise gasoline octane, petroleum-derived gasoline eventually replaced it as the primary fuel for automobiles and light-duty trucks. From the early 1970’s and up through the present, ethanol from corn, has been increasingly used as a fuel; however, recently, ethanol from cellulose is being viewed with increasing interest.

Several processing options are currently available to convert cellulosic biomass into ethanol. These conversion technologies generally fall into two main categories: biochemical and thermochemical. Biochemical conversion refers to the fermentation of sugars liberated from the breakdown of biomass feedstock. Thermochemical conversion includes the gasification and pyrolysis of biomass material into a synthesis gas or liquid oil for subsequent fermentation or catalysis. The main benefit of gasification/pyrolysis over the biochemical route is that thermochemical processes can more easily convert low-carbohydrate or “non-fermentable” biomass materials such as forest and wood residues to alcohol fuels and can more readily accept a wider variety of feedstocks.[203] However, the thermochemical process does have some drawbacks, such as tar production and clean-up gas procedures that require additional capital investment.

Since commercial production of cellulosic ethanol has not yet begun, it is unclear which process options will prove most viable or whether additional variations will emerge. At least in the near future, there have been plans to build both stand-alone biochemical and thermochemical ethanol processing plants. In addition, some investors are currently supporting research and development in both cellulosic processing procedures, neither choosing one conversion over the other.[204] The following subsections describe the process steps, current challenges, and targeted areas for improvement for each conversion method.

#### 1.4.3.1.1 Biochemical Conversion

Unlike grain feedstocks where the major carbohydrate is starch, lignocellulosic biomass is composed mainly of cellulose (40-60 %) and hemicellulose (20-40 %). The remainder consists of lignin, a complex polymer which serves as a stiffening and hydrophobic (water-repelling) agent in cell walls.[205] Cellulose and hemicellulose are made up of sugars linked together in long chains called polysaccharides. Once hydrolyzed, they can be fermented into ethanol. Currently, lignin cannot be fermented into ethanol, but could be burned as a by-product to generate electricity.

Both starch (corn grain) and cellulosic feedstocks must be hydrolyzed prior to fermentation. Structural differences at the molecular level make it far more difficult, and therefore more costly, to hydrolyze cellulosic biomass than it is to hydrolyze starch. Glucose, $C_6H_{12}O_6$, the repeating monomer in both starch and cellulose, is a six-sided ring, similar in conformation to the classic ‘chair’ conformation of cyclohexane or benzene, except one carbon atom in the ring is replaced by an oxygen atom. For uniformity (and ease) of discussion, it is generally assumed that the first carbon atom next to the oxygen, is carbon #1; the numbering, 2-5, continues around the ring with oxygen in the 6th position; one of the four bonds of the fifth carbon atom is attached to the oxygen atom to complete the ring, one is attached to hydrogen atom and the fourth to a $-CH_2OH$ group. Thus, a glucose molecule/monomer is a six-sided molecule, but not a six-carbon ring (although there are six-carbon molecules present, one of which is in the –methylhydroxy group).

The main difference between starch and cellulosic plant matter is that starch polysaccharides are made up of α-glucose monomers, uniformly strung together by α-linked 1,4-glucosidic bonds whereas cellulosic polysaccharides are made up of β-glucose monomers, strung together through β-linked 1,4-glucosidic bonds. In starch with the α-conformation, the hydroxyl group on carbon #1 is in the axial or α-position, which causes the -OH’s on each successive glucose monomer to end up on the same side of the polymer. There are also 1,6-linked glucose branches that occur irregularly on approximately one in twenty-five glucose units.[206] The -OH groups on the same side of the polymer, along with the randomly attached 1,6-glucose branches, leaves starch polymers relatively weak, flexible, and able to easily wrap and twist together to form tiny granules ( e.g., common, everyday corn starch),

Cellulosic polysaccharides are in the β-conformation with the hydroxyl group on carbon #1 is positioned away from the ring, in the equatorial or β-position, which causes the -OH’s on each successive glucose monomer, added to the chain, to end up on opposite sides of the polymer. The hydroxyl groups lined up evenly and uniformly along opposite sides of each polymer strand allow intra-molecular hydrogen bonds to develop within each monomer. They also allow inter-molecular hydrogen bonds to develop between adjacent polymers to form tight, rigid, strong, mostly straight polymer bundles called microfibrils that act as the core constituent in the formation of plant cell walls that are also insoluble in water and resistant to chemical attack. The β-conformation and the resulting hydrogen bonds stabilize the glucose chair structure to help minimize the polymer's flexibility (which hinders hydrolysis) and to add to its strength.

The second cellulosic component is called hemicellulose. It consists mainly of a random mixture of highly branched and heavily substituted five- and six-carbon rings. The five-carbon residues are usually D-xylose and L-arabinose; the six-carbon residues are usually D-galactose, D-glucose, and D-mannose, and uronic and acetic acid. Hemicellulose is not as rigid or strong as cellulose, but does contribute additional strength and helps protect the plant cell wall against attack by microbes or water. Hemicellulose is relatively easy to hydrolyze, due to its highly branched, somewhat random or non-uniform structure.

Lignin, the third principle component, is a complex, cross-linked polymeric, high molecular weight substance derived principally from coniferyl alcohol by extensive condensation polymerization. Covalently bonded to the hemicellulose, it is essentially a glue-like polymer that covers the cellulose and hemicellulose polymer cell walls and helps hold them together, provides additional strength, helps resist microbial decay, and perhaps most importantly, for this discussion, inhibits hydrolysis. Its molecular weight is around 10,000.[207] While both cellulose and hemicellulose contribute to the amount of fermentable sugars for ethanol production, lignin does not, but can be combusted to provide process energy in a biochemical plant or used as feedstock to a thermochemical process.[208]

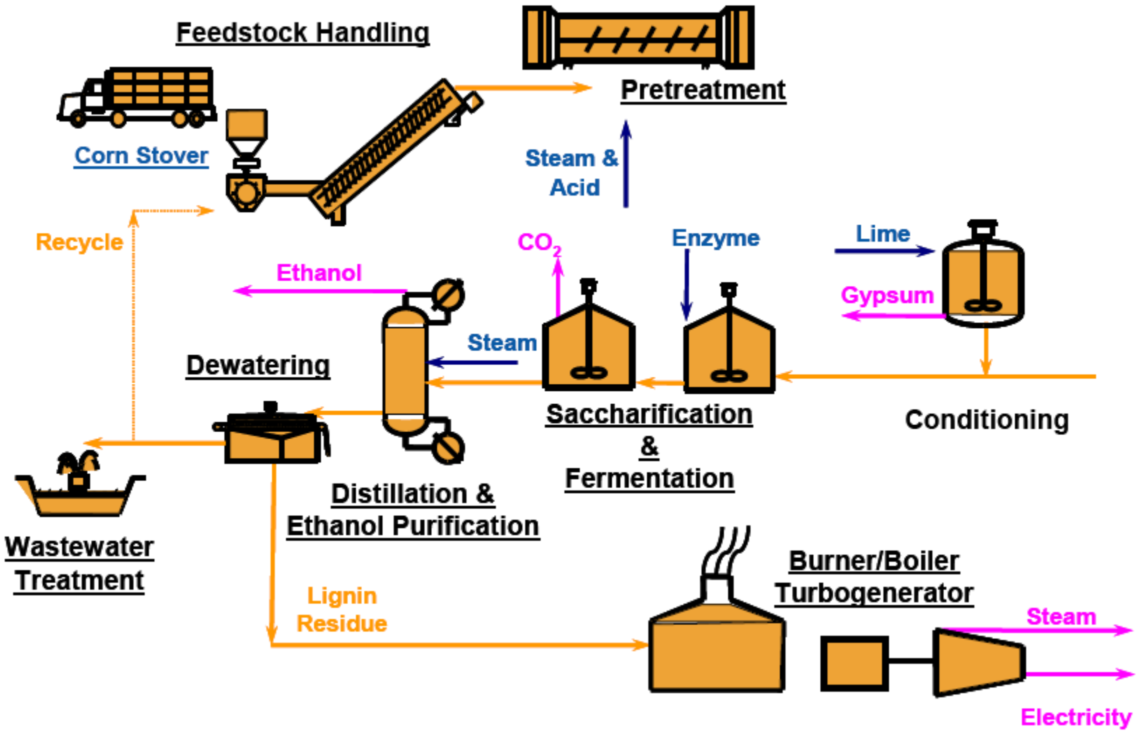
To review, a significant part of the reason it is more difficult and more costly to produce ethanol from cellulosic feedstocks, has to do with the differences in the molecular structures of simple starch and those of cellulosic plant matter. That is, as a plant grows, glucose monomers are added to the polysaccharide chains of the plant cell walls through condensation reactions. In general, condensation is a chemical process by which two molecules are joined together to make a larger, more complex molecule, and a molecule of water is a byproduct of the reaction. In the formation of polysaccharides, and enzyme catalyzes the reaction wherein the -OH group on carbon #1 of one monomer, or glucose residue, reacts with the -OH on carbon #4 or #6 of another residue. An H-OH ($H_2O$ or water) molecule is removed leaving an -O- that links the monomers together to form the polysaccharide chain. Again, depending on the direction of the –OH group at carbon 1, it may be called an alpha (as in starch) or a beta (as in cellulose) linkage.[209]

Hydrolysis is the reverse reaction. The -H from an H-OH (water) molecule is added to one monomer and the remaining -OH is added to its pair, e.g., to the next monomer on the chain, to regenerate separate glucose monomers. During starch hydrolysis, water and water borne hydrolyzing enzymes can easily penetrate the randomly formed polymers (the tiny granular particles or bundles) in order to break the bonds to release glucose monomers. However, the cellulosic or glucan polymers formed in tightly packed, dense, rigid microfibrils are especially resistant to water and hydrolyzing enzymes. Xylan, the main constituent of hemicellulose, is more easily hydrolyzed than cellulose, but not easily fermented. Cellulose is not easily hydrolyzed, but readily ferments into alcohol. These are two of the major problems that must be satisfactorily resolved for biochemical conversion of cellulosic feedstocks.

Biochemical conversion processes typically use dilute acid with enzymes or concentrated acid to convert cellulosic biomass to sugar for fermentation to ethanol. Concentrated acid hydrolysis is fairly well developed and is being pursued to commercialization in certain niche situations. For example, concentrated acid hydrolysis is suitable for feedstocks such as municipal solid wastes which have largely heterogeneous mixtures.[210] Concentrated acid hydrolysis is typically much faster than enzymatic approaches, albeit at the cost of reduced sugar yields due to undesirable side reactions.[211] Enzymatic hydrolysis is mostly suitable for homogeneous mixtures because specific enzymes are needed to convert a given type of feedstock. The cost to enzymatically hydrolyze cellulose is expected to decline significantly as these technologies continue to improve.[212]

In general, steps of the biochemical process include: feedstock pretreatment, hydrolysis, saccharification and fermentation, ethanol dehydration, and lignin recovery. Refer to Figure 1.4-6 for an illustration of the enzymatic biochemical production process. We used NREL's study as a guide to describe, somewhat generically, how such a process might work. Refer to the NREL technical documents for greater detail.[213,214]

**Figure 1.4-6.**
**Cellulosic Ethanol Biochemical Production Process (Enzymatic)**



*Stage 1 – Feedstock Pretreatment*

Lignocellulosic biomass must undergo at least some pretreatment prior to hydrolysis. During the early years of cellulosic ethanol production (e.g., 2010 to 2015), we anticipate that this stage will likely occur within the facility. In the out years covered by this rule (2022) we believe that this stage may be moved outside the plant gate (e.g., upstream of the ethanol plant) to reduce transportation costs that are typically high due to the low density of this type of biomass. The biomass is pretreated with either a physical or chemical pretreatment method to help the polysacharides become more accessible to hydrolysis. Studies have shown a direct correlation between the removal of lignin and hemicellulose and the digestibility of cellulose.[215]

Physical pretreatment nearly always includes size reduction by some type of grinding, shredding, or chopping. For example, in order to biochemically process wood chips, e.g., poplar trees or willows, the chips must be reduced in size to 1-mm or less in order to increase the surface area for contact with acid, enzymes, etc. Breaking up a 5-in tree stem into 1-mm pieces would consume a large amount of energy. On the other hand, corn stover chips for a biochemical process can range up to a maximum size of 1.5 inches.[216]

Chemicals are also used for pretreatment. The most common chemical pretreatment methods for cellulosic feedstocks are dilute acid, hot water, alkaline, organic solvent, ammonia, sulfur dioxide, carbon dioxide, or other chemicals to make the biomass more digestible by the enzymes.[217,218] These chemicals cause the biomass to react quite differently.[219] For example, instead of hydrolyzing the hemicellulose (as in acidic pretreatments), an alkaline approach tends to leave the hemicellulose and cellulose intact. Enzymes are therefore required to digest both hemicellulose and cellulose at the same time when a basic pretreatment is used.

Different pretreatment approaches also affect the amounts of degradation products (e.g. furfurals, acetates) that occur from the decomposition of hemicellulose and lignin. This is important since these degradation products can inhibit microorganisms in the fermentation step. A well known pretreatment method that does not degrade biomass sugars or produce fermentation inhibitors is ammonia fiber expansion (AFEX). During AFEX, liquid ammonia is added to the cellulosic material followed by a rapid pressure release.

Each type of feedstock, whether softwoods, corn stover or bagasse, requires a particular combination of pretreatment methods to optimize the yields of that feedstock, minimize the degradation of the substrate, and maximize the sugar yield. Pretreatment of cellulosic biomass in a cost-effective manner is a major challenge of cellulose-ethanol technology research and development.[220] For more information on feedstock considerations and their impacts on biorefining refer to the NREL report completed for the final rule.[221]

*Stage 2 – Pretreatment and Hydrolyzate Conditioning*

NREL refers to this stage as a combination of pretreatment and hydrolysis. In their process flow diagram, the washed and sized-reduced feed is directly heated with steam and mixed with dilute sulfuric acid. The process converts, primarily, the hemicellulose polysaccharides xylan, mannan, arabinan and galactan, to produce the mixed sugars and further helps prepare the cellulose for hydrolysis. A small amount of glucan in the hemicellulose and in the cellulose is converted into glucose. The rundown from the acid hydrolysis reactor is fed to a blowdown tank that subsequently feeds a filter press. The filter press produces two main streams, a filter cake and a liquid filtrate, also called hydrolyzate. The filter cake carries the unhydrolyzed portions of the feed (e.g., glucans) among other insolubles, while the liquid carries that part of the feed that was hydrolyzed, mainly the xyloses.

The liquid portion is neutralized to remove gypsum and other contaminants that would be toxic to downstream enzymes. The cake is washed, mixed back with the detoxified liquid hydrolyzate, and fed to the saccharification reactors to hydrolyze the glucan polysaccharides.

### *Stage 3 – Saccharification and Co-Fermentation*

We should point out that this is not ‘Simultaneous Saccharification and Fermentation’ (SSF). Saccharification, in the process we’re discussing, takes place primarily in several reactors along with other intermediate treatments such as filtering and detoxifying. Using a cellulase enzyme cocktail, saccharification of the cellulose to glucose occurs first at an elevated temperature to take advantage of increased enzyme activity, which reduces the quantity of required enzyme as well as the reaction time.

The cellulase enzymes used to convert cellulose to sugars can be obtained in two ways. The first option is for a plant to produce it on-site. The second option requires the plant to purchase the enzymes from off-site enzyme manufacturers. Due to a joint research effort by DOE, Genencor International, and Novozymes Biotech, the cost for production of cellulase enzymes has been drastically reduced. Such research and development in areas of enzyme production have reduced the cost of cellulolytic enzymes by a factor of 10 to 30, down to 20 to 30 cents per gallon of ethanol produced.[222,223,224] It is estimated, however, that enzyme costs will have to be further reduced to a level comparable to those used to produce ethanol from corn grain at a cost of 3 to 4 cents per gallon of ethanol. The current challenge is to develop the correct enzyme “cocktails” to reflect differences in the physical and chemical characteristics of all the various types of cellulosic materials. It may be easier, therefore, to process single feedstocks (more homogeneous) rather than multiple feedstocks, in which variations are more likely.

Following cellulose saccharification, both the glucose and xylose sugars are co-fermented. Although xylan, the hemicellulose polysaccharide, is more easily hydrolyzed than glucan (cellulose polysaccharides), the xylose sugar is more difficult to ferment than is the glucose sugar. Different microbes as well as different residence times and process conditions may be required for each.

Because xylan can make up as much as 25% of plant matter it is imperative that as much of it as possible be fermented; the economic viability of biochemically produced ethanol depends heavily on it. This continues to be high on the list of challenges researchers are working on, but good progress has been made toward fermenting a higher percentage of xylose during the past few years.[225]

#### *Stage 3A – Consolidated Bioprocessing e.g., Simultaneous Saccharification and Fermentation (SSF)*

During the past few years, researchers have been looking for ways to combine saccharification and fermentation into a single step through the use of enzyme/microbe cocktails. If successful, we expect there could be significant capital cost savings in that fewer reactors and other support equipment and piping would be necessary. Also, it may be possible to reduce processing times if hydrolysis reactions can take place simultaneously, rather than sequentially. Such strategies are known as consolidated bioprocessing (CBP). CBP, however, is currently hampered by the relative inability of yeast to process recombinant cellulases (enzymes that help convert cellulose to sugars), and the relative lag in the development of molecular biological methods to manipulate organisms that secrete cellulases naturally.[226]

#### *Stage 4 – Ethanol Dehydration*

NREL's process model indicates that the fermentation reactor rundown stream, now called 'beer,' runs down the beer column feed surge tank. The beer column feed consists of about 83% water and only 5.5% ethanol; the balance of the mixture is very complex, but consists mostly of lignin. The beer column removes the dissolved $CO_2$ overhead and produces a water/ethanol bottom stream that is fed to a rectification column. According to NREL's model, the rectification column bottoms would be mostly water with about 0.05% ethanol that's recycled back to the process. The rectification column overhead that consists of about 92.5% ethanol and 7.5% water, is fed to a molecular sieve that produces a 99.5 wt.% ethanol product stream with about 0.5 wt.% water. Gasoline, a denaturant, is added to produce ethanol fuel.

#### *Stage 5 – Lignin Recovery*

Following the saccharification and fermentation of the xylan and glucan to ethanol, the lignin is gradually concentrated with other solids into a moist cake-like product that is about 48% insoluble solids. About 80% of the 48% insoluble solids is essentially lignin microbial cells, and other unconverted biomass remnants, (e.g., cellulose, xylose, glucan, xylan, other oligomers, etc.,) from the process. This material can be either combusted to provide process heat for the biochemical operation for a co-located starch ethanol plant, or as we discuss in the following section, could be used as feedstock for a thermochemical unit.

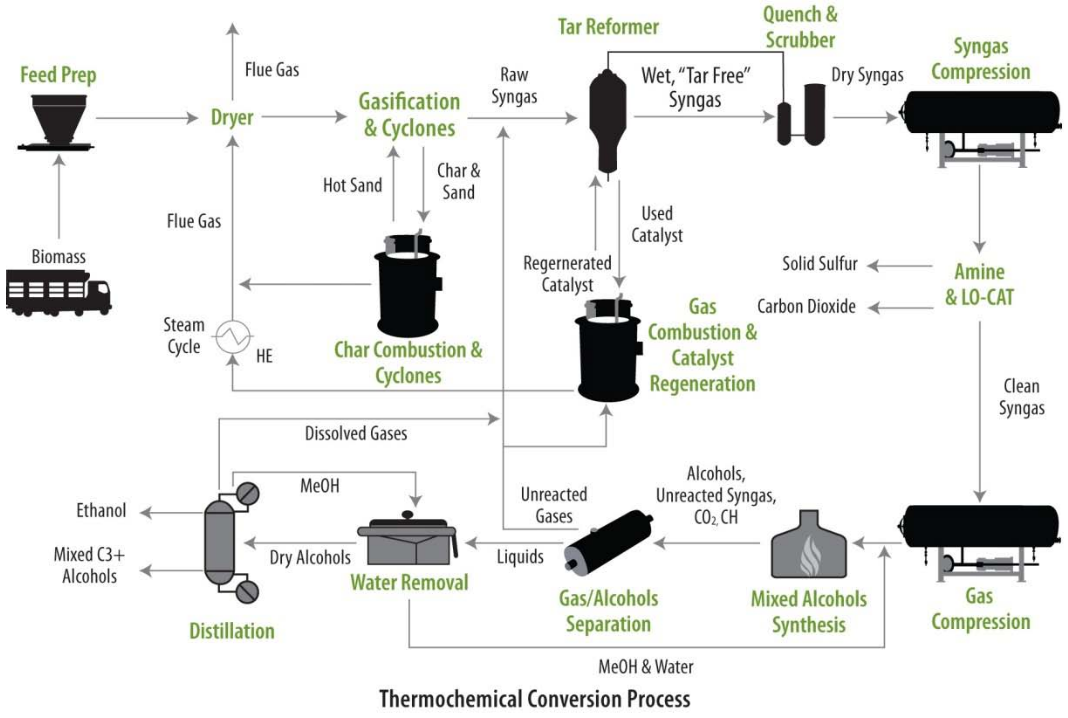
### 1.4.3.1.2 Thermochemical Conversion

Thermochemical conversion involves biomass being broken down into intermediates using heat and upgraded to fuels using a combination of heat and pressure in the presence of catalysts.[227] Thermochemical processes include pyrolysis (absence of oxygen), gasification (partial oxidation in the presence of a gasifying agent, usually air, oxygen, and/or steam), and combustion (complete oxidation). The former two conversion processes, pyrolysis and gasification, can be used to convert biomass into energy carriers for transportation use. It is important to note that these processing steps are also applicable to other feedstocks (e.g., coal or natural gas); the only difference is that a renewable feedstock is used (i.e. biomass) to produce cellulosic biofuel. A thermochemical unit can also complement a biochemical processing plant to enhance the economics of an integrated biorefinery by converting lignin-rich, non-fermentable material left over from high-starch or cellulosic feedstocks conversion.[228] We discuss the gasification and pyrolysis processes below.

Gasification

Compared to corn ethanol or biochemical cellulosic ethanol plants, the use of biomass gasification may allow for greater flexibility to utilize different biomass feedstocks at a specific plant. Mixed biomass feedstocks may be used, based on availability of long-term suppliers, seasonal availability, harvest cycle, and costs. Agricultural residue, energy crops, wood residues, and municipal solid waste are all being considered as potential feedstocks. Geographic location, availability of biomass, the existence of biomass suppliers, and costs would all likely influence the mix of biomass feedstocks utilized. The general steps of the gasification thermochemical process include: feedstock handling, gasification, gas cleanup and conditioning, fuel synthesis, and separation. Refer to Figure 1.4-7 for a schematic of the thermochemical cellulosic ethanol production process through gasification. For greater detail on the thermochemical mixed-alcohols route refer to NREL technical documentation.[229]

**Figure 1.4-7.**
**Cellulosic Ethanol Thermochemical Gasification Process**



*Stage 1 – Feedstock Handling*

The particle size requirement for a thermochemical process is around 10-mm to 100-mm in diameter.[230] Once the feed is ground to the proper size, flue gases from the char combustor and tar reformer catalyst regenerator dry the feed from the as received moisture level of around 30% to 50% moisture to the level required by the gasifier.

*Stage 2 – Gasification*

There are two general classes of gasifiers. First, partial oxidation (POx) gasifiers (directly-heated gasifiers) use the exothermic reaction between oxygen and organics to provide the heat necessary to devolatilize biomass and to convert residual carbon-rich chars. In POx gasifiers, the heat to drive the process is generated internally within the gasifier. A disadvantage of POx gasifiers is that oxygen production is expensive and typically requires large plant sizes to improve economics.

The second general class, called indirect gasification, uses steam gasifiers to accomplish gasification through heat transfer from a hot solid or through a heat transfer surface. Either the byproduct char and/or a portion of the product gas can be combusted with air (external to the gasifier itself) to provide the energy required for gasification. Although steam gasifiers have the advantage of not requiring oxygen, most operate at low pressure and therefore require product gas compression for downstream purification and synthesis unit operations. [231,232]

There are different subcategories of gasifiers which are either directly or indirectly heated. One subcategory is termed a bubbling fluidized bed gasifier and it employes a bubbling fluidized bed of inert material and the reactant (biomass) is also bubbled through the fluidized bed. A second variant is the circulating fluidized bed gasifier which is similar to the bubbling fluidized bed reactor except that a high feedstock and air flow rate circulates the fluidized bed out of and back into the reactor. For the fluidized bed, the bed material may either be inert alumina or sand which helps the heat transfer. There are also fixed bed reactors which either feed the reacting gas (oxygen or air) upward or downward through a fixed bed of the reactant (biomass). Because of the tar formed when using biomass as a feedstock, a second reactor is sometimes added which solely targets converting the tar to syn-gas. If the biomas feedstock is ground to a sufficiently small particle size, or liquefied, the biomass is considered to be “entrained” in the reactor, and the reactor is defined as an entrained flow reactor.

Indirect gasification using an entrained flow gasifier is described for this example. The gasification process begins as the biomass is fed to the reactor containing a heat transfer media, such as sand, and is partially reacted with air (or oxygen) which is introduced to the bottom of the reactor. The air serves as the carrier-gas and as the oxidant for partially oxidizing the biomass to syn-gas, carbon monoxide and hydrogen. In addition to the syngas produced, char and coke are also formed. The heat for the endothermic gasification reactions is supplied by circulating heat transfer media (e.g. sythetic sand) between the gasifier and the char combustor. The heat generated by the combustion of the char and coke heats the heat transfer media to over 1800°F. The syngas is separated from the sand and ash and sent to gas cleanup.

*Stage 3 – Gas Cleanup & Conditioning*

Once the biomass is gasified and converted to syngas, the syngas must be cleaned and conditioned. This raw syngas has a low to medium energy content depending on the gasifying agent and consists mainly of CO, $H_2$, $CO_2$, $H_2O$, $N_2$, and hydrocarbons.  The minor components, tars, sulfur, nitrogen oxides, alkali metals, and particulates have the potential to negatively affect the syngas conversion steps.  Therefore, unwanted impurities are removed in a gas cleanup step and the gas composition is further modified during gas conditioning.  Gas conditioning steps include sulfur polishing to remove trace levels of $H_2S$ and water-gas shift to adjust the final $H_2$/CO ratio for optimized fuel synthesis.

### *Stage 4 – Fuel Synthesis*

After cleanup and conditioning, the "clean" syngas is comprised of essentially CO and $H_2$.  The syngas is then converted into a liquid fuel by either a catalytic process or through the use of a microorganism.  The fuel producer has the choice of producing diesel fuel or alcohols from syngas by optimizing the type of catalyst used and the $H_2$/CO ratio.  Diesel fuel has historically been the primary focus of such processes, as it produces a high quality distillate product, however, with the 45 cent tax subsidy currently available for ethanol production, it may be economically advantageous for fuel producers to convert syngas to ethanol instead of to diesel fuel.  Production of cellulosic diesel is discussed in further detail in the following Section 1.4.3.2.

Conceptual designs and techno-economic models have been developed for ethanol production via mixed alcohol synthesis using catalytic processes.  The proposed mixed alcohol process produces a mixture of ethanol along with higher normal alcohols (e.g., n-propanol, n-butanol, and n-pentanol).  The by-product higher normal alcohols have value as commodity chemicals and fuel additives.  Typically the mixed alcohol products are high in methanol, but contain a wide distribution of several different alcohols.  One concept proposed in literature is to completely recycle this methanol in order to increase the production of ethanol and higher alcohols which are generally more valuable.  This concept was modeled by NREL for the thermochemical production of ethanol for the year 2012.  Total mixed alcohol yield was 94.1 gallons per dry ton, in which 85% of the total alcohol product was ethanol.  This was made possible through the addition of an almost complete recycle of methanol within the process.[233] For the final rule, we worked with NREL to develop the thermochemical mixed-alcohols model for the 2015 and 2022 timeframe, as discussed in greater detail in the technical document.[234] The analyses were used to inform us of the materials and energy use for these technologies for our lifecycle analyses discussed in Chapter 2.

In contrast to the catalytic processing of syngas to produce fuels there is also a fermentation process being pursued that utilizes a special microorganism (Clostridium ljungdahlii) to convert the syngas to ethanol.[235]  This combined syngas and fermentation process has the benefit of having a significantly faster processing time, on the order of minutes, as compared to the typical biochemical process on the order of days.[236]

### *Stage 5 – Alcohol Separation*

The liquid rundown from the low-pressure separator is dehydrated in vapor-phase molecular sieves, producing the dehydrated mixed alcohol feed into a methanol/ethanol overhead stream and a mixed, higher molecular weight alcohol bottom stream. The overhead stream is further separated into a methanol stream and an ethanol stream.

*Heat & Power*

A carefully integrated conventional steam cycle produces process heat and electricity (excess electricity is exported). Pre-heaters, steam generators, and super-heaters generate steam that drives turbines on compressors and electrical generators. The heat balance around a thermochemical unit or thermochemical/biochemical combined unit must be carefully designed and tuned in order to avoid unnecessary heat losses.[237]

### 1.4.3.2 Cellulosic Diesel

Cellulosic diesel fuel tecnologies convert cellulosic feedstocks to diesel fuel. There could be a whole set of technologies which fall in this category including thermochemical and other chemical processes and biochemical processes.

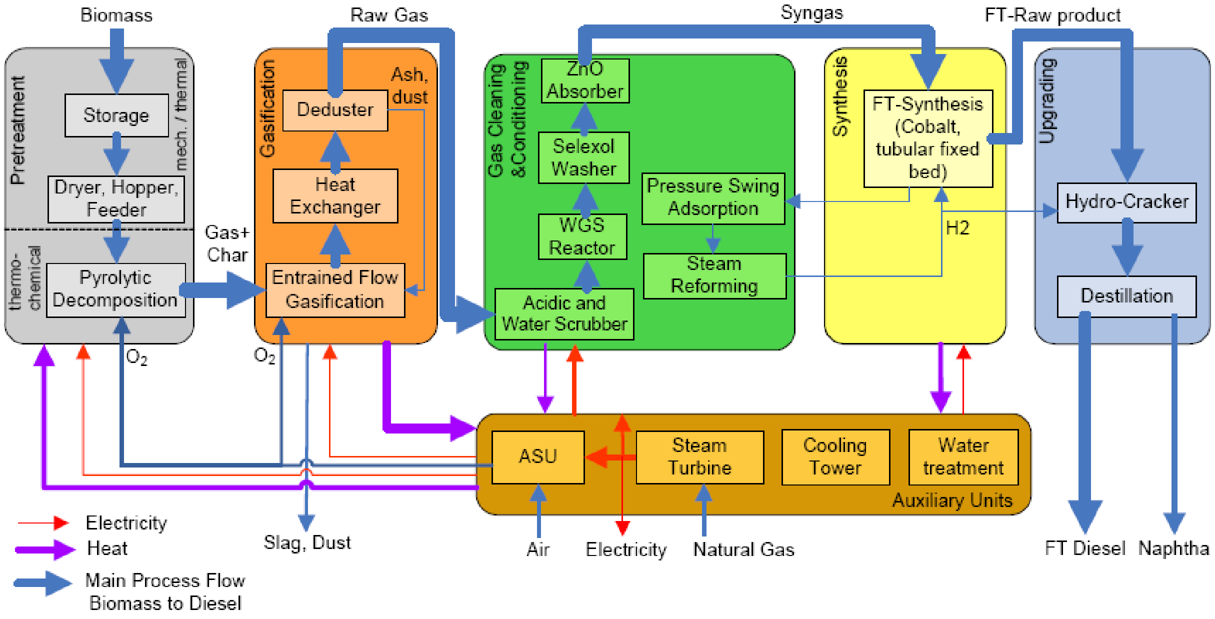
*BTL Technology*

One important cellulosic diesel fuel technology is a thermochemical process which is also termed biomass-to-liquids (BTL). Like the thermochemical ethanol process described previously, the BTL process produces a syngas from biomass. However, instead of reacting the syngas to alcohol, the syngas is fed to a Fischer-Tropsch (FT) reactor to primarily produce diesel fuel and some naphtha.[238]

The BTL method removes contaminants from the gasification stream prior to the reactions that form the liquid compounds. The resulting liquid fuel is essentially contaminant-free and is very similar to petroleum-based diesel fuel – in fact, its cetane number is higher than petroleum-based diesel fuel making it somewhat better in quality. Thus it can be easily blended with or used interchangeably with petroleum-based diesel fuel.

Figure 1.4-8 is a block diagram of a BTL process.

**Figure 1.4-8.**
**Biomass to Liquids (BTL) Thermochemical Gasification Process**



BTL plants, like thermochemical ethanol plants, are capital intensive plants with many subunits associated with them. The first couple of steps of BTL plants, including biomass processing and gasification, are similar to the thermochemical cellulosic ethanol plants described above. However, once the syngas is produced, it is then cooled producing high pressure steam, and is scrubbed to remove particulate matter. Impurities such as mercury, arsenic and trace metals are removed by a sulfur impregnated carbon reactor. The syngas is further treated in either a Selexol or Rectisol unit to remove hydrogen sulfide and concentrated carbon dioxide (CO2). The syngas is sent to a water gas shift reactor (WGS) to which causes a shift to more hydrogen and less carbon monoxide, which is necessary to establish an optimal mix of hydrogen and carbon for the downstream Fischer-Tropsch (FT) reactor.

The cleaned and water-shifted syngas is sent to the FT reactor where the carbon monoxide and hydrogen are reacted over a FT catalyst. The FT catalyst is either iron-based or cobalt-based. The cobalt catalyst is more expensive, although it does not require a recycle, while the less expensive iron catalyst does require a recycle. The FT reactor creates a syncrude, which is a variety of hydrocarbons that boil over a wide distillation range (a mix of heavy and light hydrocarbons). The syncrude from the FT reactor is sent to a distillation column where it is separated into various components based on their vapor pressure, mainly liquid petroleum gas (LPG), naphtha, distillate and wax fractions. The heavier compounds are hydrocracked to maximize the production of diesel fuel. The distillate boiling compounds have high cetane and thus are of high quality for blending into diesel fuel. Conversely, the naphtha material is very low in octane thus, it would either have to be upgraded, or blended down with high octane blendstocks (i.e., ethanol), or be upgraded to a higher octane blendstock to have much value for use in gasoline. The naphtha could also be sold as feedstock for the petrochemical market for manufacturing chemical products such as ethylene and benzene.

The unreacted carbon monoxide and hydrogen and any gaseous hydrocarbon material are burned to produce electricity in a turbine. The waste heat from the gas turbine along with the steam created to cool the syn-gas, may be sent to steam turbines to produce additional electricity. Most of the electricity would be used within the BTL plant, however, some could be sold to raise additional revenues.

Pyrolysis Diesel Fuel and Gasoline

Pyrolysis oils, or bio-oils, are produced by decomposing cellulosic biomass at lower temperatures than the gasification process, thus producing a liquid oil instead of a synthesis gas.[239] The reaction can occur either with or without the use of catalysts, but it occurs without any additional oxygen being present. The oil produced varies in oxygen content or viscosity according to the feedstock used. The oil must have particulates and ash removed in filtration to create a homogenous product and is further upgraded to hydrocarbon fuels via hydrotreating and hydrocracking processing, which reduces its total oxygen content. Some believe that pyrolysis could have a significant economic advantage over other cellulosic ethanol approaches, however, very little has been done in terms of optimizing the process, and as such, there are still many possibilities yet to be explored.[240] One of the finished fuels produced by the pyrolysis process is diesel fuel, however, a significant amount of gasoline would likely be produced as well.

### 1.4.3.3 Developing Technologies

When evaluating the array of biofuel technologies which could produce one or more fuels that could qualify under RFS2, we found that it is helpful to organize them into fuel technology categories. Organizing them into categories eases the task of understanding the costs and life cycle impacts of these technologies because like technologies likely have similar cost and life cycle impacts. The simplest organization is by the fuel produced. However, we frequently found that additional subdivisions were also helpful. Table 1.4-1 provides a list of technologies, the cellulosic fuels produced and a list of many of the companies which we learned are pursuing the technology (or something very similar to the technology listed in the category).

**Table 1.4-1.**
**List of Biofuel Categories, the Fuels Produced and the Companies Pursuing the Technologies**

| Technology Category | Fuels Produced | Companies |
|---|---|---|
| Biochemical from Corn Grain | Ethanol | ICM, Delta T, Broin |
| Biochemical Cellulosic Ethanol | Ethanol | Abengoa, AE Fuels, Cornell Univ., Citrus Energy, DuPont/Danisco, Florida Crystals, Novenzymes, Poet, Western Biomass, ICM, Alltech/Ecofin, IOGEN, Qteros, and Raven Biofuels, BPI, New Age Energy, Universal, Fiberight, KL Energy. |
| Thermochemical/Catalytic conversion of Cellulose | Ethanol | Range Fuels, Pearson Technologies, Fulcrum Bioenergy, Enerkem, and Gulf Coast Energy. |
| Thermochemical/Biochemical conversion of Cellulose | Ethanol | Coskata and INEOS Bio. |
| Strong Acid Hydrolysis of Cellulose/Biochemical | Ethanol | Blue Fire, Arkenol, Pencor, Pangen, Auburn Univ., Agresti. |
| Dilute Acid, Steam Explosion of Cellulose/Biochemical | Ethanol | Verenium, BP, Central Minnesota Ethanol Coop. |
| Consolidated Bioprocessing (one step hydrolysis and fermentation) of Cellulose/Biochemical | Ethanol | Mascoma |
| Biochemical conversion of Cellulose via carboxylic acid | Ethanol, Gasoline, Jet Fuel, Diesel Fuel | Terrabon, Swift Fuels, Zeachem |
| Thermochemical/Fischer Tropsch | Diesel Fuel and Naphtha | Choren, Flambeau River Biofuels, Baard, Clearfuels, Gulf Coast Energy, Rentech, TRI. |
| Thermochemical/Fischer Tropsch | DME | Chemrec, New Page. |
| Catalytic Depolymerization of Cellulose | Diesel, Jet Fuel or Naphtha | Cello Energy |
| Biochemical conversion of Cellulose | Diesel, Jet Fuel or Naphtha | Bell Bioenergy |
| Catalytic Reforming of Sugars | Gasoline | Virent |
| Biochemical conversion of Sugars | Diesel, Jet Fuel or Gasoline | Amyris, Gevo, LS9. |
| Biochemial of Sugars – converted corn ethanol plants | Isobutanol | Gevo/ICM. |
| Pyrolysis of Cellulose | Diesel, Jet Fuel, or Gasoline, | Envergent (UOP/Ensyn), Dynamotive, Petrobras, Univ. of Mass, KIOR. |
| Hydrotreating of Plant Oils | Renewable Diesel Fuel | UOP, Neste, Eni,Conoco-Phillips, Dynamic Fuels (Syntroleum/Tyson). |
| Fatty Acid Methyl Ester (FAME) | Biodiesel | Many |
| Free Fatty Acid to Biodiesel | Biodiesel | Endicott |
| Production of Algae Oils via Photobioreactor or open pond | Algae Oil (Biodiesel or Renewable Diesel Fuel) | Solazyme, Algenol, Aurora Biofuels, Petrosun, Sapphire Energy, Livefuels, Solix, HR Biopetroleum (Cellana), XL Renewables, Petroalgae, Synthetic Genomics, GreenFuel. |

Of the technologies listed above, many of them are considered to be “second generation” biofuels or new biofuel technologies capable of meeting either the advanced biofuel or cellulosic biofuel RFS standard. The following sections describe specific companies and the new biofuel technologies which the companies have developed or are developing. This summary is not meant to be an unabridged list of new biofuel technologies, but rather a description of some of the more prominent or interesting of the new biofuel technologies that serve to provide a sense of the technology categories listed above. The process technology summaries are based on information provided by the respective companies. EPA has not been able to confirm all of the information, statements, process conditions, and the process flow steps necessary for any of these processes and companies.

*Sugar to Diesel Fuel - Amyris Biotechnologies*

The Amyris technology produces hydrocarbon fuels from sugars through biochemical reactions. The technology uses custom designed yeast cells and is modular in design and can be collocated with existing ethanol plants to produce diesel fuel and gasoline.

Amyris's yeast cells are the key drivers of their conversion process. The process uses the same feedstocks that are currently used to make corn starch ethanol, which could be sugar cane or corn grain. Amyris has a 100 gallon per week pilot plant operating in Emeryville, CA, and in mid-2009 has completed construction of a pilot plant as well as a commercial demonstration plant in Brazil to showcase their technology. Amyris intends to convert its own sugar cane mills over with this technology starting in 2011. In 2012, Amyris expects to begin converting sugar cane mills owned by others with its sugar to hydrocarbon technology.

The diesel fuel capable of being produced from the process is compatible with the existing petroleum distribution system and provides better storage and cold flow properties than biodiesel.

*Biochemical to Diesel Fuel - Bell Bio-Energy*

Bell Bio-Energy has developed a biochemical technology which uses genetically engineered bacteria to convert cellulosic feedstocks directly to synthetic hydrocarbon fuels and compost. Depending on the types of bacteria used, this process can produce specific hydrocarbon types which can either be methane or other light hydrocarbons, gasoline, diesel or jet fuel type hydrocarbon compounds. For example, if a bacterium is chosen to produce gasoline, the bacteria may only produce octane, an eight carbon hydrocarbon molecule that boils within the distillation temperature range of gasoline.

After the inventors of this process completed their development work, they discussed their technology with the Department of Defense which became interested in this technology for providing fuels to their land and air based vehicles. The military agreed to partially fund the establishment of pilot plants at different military bases, however, of the original 7 conceived pilot plants, only one pilot plant was built at Fort Stewart in Georgia. The Fort Stewart pilot plant began operating in late 2008. Bell Bioenergy intends on starting up two demonstration plants – one associated with the University of California in Fresno, the other with the City of Atlanta. The primary output of these plants will be compost, however, these two plants are also expected to produce 1 to 2 million gallons of diesel fuel on an annual basis.

The technology works by first grinding the cellulosic feedstock into a smaller size and then immersing the ground cellulose with bacteria into water. The bacteria begin to digest the cellulose after only several hours, but require 30 to 60 days to fully digest the cellulose. The produced fuel is constantly removed from the reaction vessel, and a significant amount of organic material is also produced which will be marketed as potting soil. The process is expected to produce 30 to 40 gallons of renewable product per ton of feedstock and the simplicity of the process results in low capital costs per volume produced.

### *Strong Acid Hydrolysis/Biochemical - BlueFire Ethanol*

BlueFire Ethanol has a commercial strong acid hydrolysis technology process that converts cellulosic materials into ethanol. The technology can make ethanol from urban trash, rice and wheat straws, wood waste and other agricultural residues. Acid hydrolysis is the main reaction mechanism to convert cellulosic and hemicellulosic material into simple sugars such as hexose and pentose or "C6 and C5" sugars. Fermentation of these sugars with microbes converts these sugars into ethanol. This process for converting cellulosic and hemicellulosic material into ethanol via acid hydrolysis and fermentation has been around for many decades; though it has not been economically competitive as the cost was not competitive with transport fuel made from petroleum. BlueFire's process is claimed to offer several improvements to existing acid hydrolysis technology, giving higher ethanol yields and lower production costs.

BlueFire uses a proprietary concentrated acid hydrolysis system and several other process improvements to make ethanol production more economically attractive than older acid hydrolysis methods. Some of BlueFire's stated improvements include a more efficient acid recovery system; higher sugar purities and concentrations; use of more efficient microbes to ferment C6 and C5 sugars into ethanol; the processes ability to use biomass feedstock's containing silica. The BlueFire process consists of the following main components; feedstock preparation; decrystallization/hydrolysis reaction; filtration of solids and liquids; separation of the acid and sugars; fermentation of the sugars and product separation. For product separation, ethanol effluent is separated using distillation and then dehydrated with molecular sieve technology.

BlueFire has successfully operated a pilot plant for six years near their headquarters in Southern California. BlueFire is in the process of building its first commercial facility which will be located in Lancaster California. As of the third quarter of 2009, BlueFire had obtained the permits to build this facility and was seeking additional funding and bids for the construction of the plant. The plant is expected to start up in 2011 or 2012 and will produce up to 3.9 million gallons of cellulosic ethanol per year from municipal solid waste (MSW). BlueFire is planning to start up another cellulosic ethanol plant which they call their Mecca or El Sobrante plant also using MSW as feedstock. Although this plant was initially envisioned to be located in California, it is likely that this plant will be built elsewhere in the U.S. No start up date has been announced for their Mecca plant.

### *Chemical Depolymerization - Cello-Energy*

The Cello-Energy process is a catalytic depolymerization technology. At moderate pressure and temperature, the Cello-Energy process catalytically removes the oxygen and minerals from the hydrocarbons that comprise cellulose. This results in a mixture of short chain (3, 6 and 9 carbon) hydrocarbon compounds. These short chain hydrocarbon compounds are polymerized to form compounds that boil in the diesel boiling range, though the process can also be adjusted to produce gasoline or jet fuel. The resulting diesel fuel meets the ASTM standards, is in the range of 50 to 55 cetane and typically contains 3 ppm of sulfur. The resulting diesel fuel has been tested in Caterpiller engines to demonstrate the viability of the fuel.

The Cello-Energy process is reported to convert 94% of the hydrocarbon material to diesel fuel, although a very small amount of heavier hydrocarbons is also produced. The Cello Energy Process could be totally self-sufficient by routing 12% of the product to run generators to produce the electricity that the process needs. The only energy input is electricity - no natural gas or water is used in the process. The Cello process is on the order of 82 % efficient at converting the feedstock energy content into the energy content of the product, which is very high compared to most of today's biochemical and thermochemical processes which are on the order of 50 % efficient, or less.

Because of the simplicity of the process, the capital costs are very low. A 50 million gallon per year plant is claimed to only incur a total cost of $45 million. This is typical of the capital costs incurred when refiners expand their refineries, a very low cost for a grassroots plant. Because of its high efficiency in converting feedstocks into liquid fuel, the production and operating costs are estimated to be very low. By using some waste feedstocks today, production costs are reported to be less than $0.50 per gallon. However, even with feedstock costs in the $70 per ton range, which is the cost we used in our cost analysis, total costs would remain less than $1.00 per gallon of diesel fuel.

Cello-Energy was founded 16 years ago and after the chemistry was worked out, they built their first pilot plant in 1998. They next converted their pilot plant in 2004 to a larger continuously-operating demonstration plant that produced 4 million gallons per year of diesel fuel. In December 2008, Cello started up a 20 million gallon per year commercial demonstration plant. As of late 2009, the plant is operational, however, the production volumes are still very low. Cello is working to increase the production volume of its plant. According to the company, they are currently working to resolve materials handling and processing issues that surfaced when they attempted to scale up production to 20 MGY from a previously operated demonstration plant. As of November 2009, they had ordered new equipment and are waiting for it to arrive and be installed which they hoped would allow for operations to be restarted as early as February or March, 2010. Cello energy already has chosen locations to construct and start up two 50 million gallons per year plants by early 2011, though these are on hold until the Bay Minette facility is operational. This includes a facility in conjunction with the State of Georgia Energy Innovation Center, and one additional plant in Alabama. Cello explained that they will use prefabrication techniques so that these plants can readily be constructed, shipped and installed anywhere in the U.S.

### *Thermochemial/Fischer Tropsch - Choren*

Choren has a technology called Carbo-V, which is a Fischer-Tropsch process that can be used to make diesel fuel. The process can process a wide variety biomass and recycled material materials as feedstocks. The process converts agriculture biomass, forestry biomass, biogenic waste and recycling substances into a synthesis gas which can be further converted to a diesel fuel using a Fischer-Tropsch reactor. The Carbo-V process can also be configured without the

Fischer-Tropsch hydrocracking technology, so as to produce electricity, heat and power, methanol, and other chemical feedstocks.

The principal aspect of the Carbo-V Process is a three-stage gasification process consisting of low temperature gasification, high temperature gasification and endothermic entrained bed gasification. In the first stage, biomass is partially oxidized with air or oxygen at temperatures between 400 and 500 °C. This breaks down the feedstock into a gas containing tar and solid carbon. In the second stage, the tar is oxidized at temperatures higher than the ash's melting point, converting the tar into a synthesis gas. In the third stage, solid carbon is mechanically pulverized and blown into the hot gasification stream. The fluidized carbon endothermicly reacts with the gasification stream and is converted into a synthesis gas. In the next Fischer-Tropsch stage of the process, the synthesis gas (CO and H2) reacts with the aid of a catalyst to form hydrocarbons. The resulting hydrocarbons produced from the three stages can then be sent to a hydrocracking process to produce primarily diesel fuel.

Choren will be building a commercial Plant in Freiberg/ Saxony Germany that is expected to be operational in 2011 or 2012. Initially, the plant will use biomass from nearby forests, the wood-processing industry and straw from farmland.

*Thermochemical/Biochemical - Coskata*

The Coskata process is a gasification-based technology which produces ethanol from biomass and other forms of carbon through a biofermentation route. A wide variety of feedstocks can be used, municipal waste, agriculture waste and other carbonaceous containing material. Since this process uses combustion and biofermentation, it is not easily classifiable as either a biochemical or thermochemical production method. This process requires that the biomass or carbonaceous material be processed to a small particle size and then it is injected into a gasifier.

The gasifier combusts any dry carboneous feed stocks into syngas, comprised primarily of carbon monoxide and hydrogen. The syngas produced is fermented in a reactor by micro-organisms, which convert the carbon monoxide and hydrogen directly into ethanol. The micro-organisms are low cost and can process a wide range of carbon monoxide and hydrogen molar ratios in the syngas, providing feedstock processing flexibility. No other enzymes are required by this process for producing ethanol, providing significant cost savings over current cellulosic and corn based fermentation production methods. The Coskata process is conducted at low pressures, which offers savings on capital and energy costs. Additional energy savings can be realized by employing membrane technology to separate ethanol from the reactor decant liquid. This technology uses gravity and filtration to recover ethanol, resulting in significant savings on distillation capital and energy costs used in other cellulosic and corn based production methods. Initial ethanol production cost estimates are lower than the biochemical and thermochemical cellulosic technologies described in previously in Subsections 1.4.3.1 and 1.4.3.2.

For woody biomass, Coskata estimates that each ton of this feedstock would generate about 100 gallons of ethanol and small amounts of ash which would be burned to supply energy needs for the process. Corn stover is expected to provide similar ethanol yields as woody biomass feed stocks, though details about yields from the various feed supply stocks are not yet public.

Coskata has a bench scale pilot plant in Warrenville, IL, and its larger 40,000 gallon per year pilot plant became operational in 2009 in Madison, Pennsylvania.  Coskata is targeting to design and build a 50 million gallon per year commercial demonstration plant that it expects to be operational in 2011.

*Pyrolysis - Dynamotive Energy Systems*

Dynamotive Energy Systems Corporation has announced a pyrolysis technology that uses medium temperatures and oxygen free reactions to convert dry waste biomass and energy crops into fuels that can be used in power/heat generation and transportation vehicles.  Additionally, the process can make feedstock's that can be used to produce chemicals.  The process is flexible on the types of biomass feedstock's that can be processed.  The fuel produced from the Dynamotive process is called "BioOil" and contains up to 25% water, though the water is intimately mixed and does not easily separate into another phase with time.  Since the BioOil contains significant amounts of water, it is not directly useable as fuel in conventional vehicles and would have to be converted via another catalytic conversion processing step.  The additional catalytic step envisioned for this would combust the material into a synthesis gas which would then be converted into diesel fuel or bio-methanol via a catalytic reaction (the BTL process).  The diesel fuel produced is expected to be compatible with existing petroleum diesel fuels.

Three products are produced by the Dynamotive process, BioOil (60-75% by weight), char (15-20% wt.) and non-condensable gases (10-20% wt.).  The char produced is similar to coke and can be used as fuel by other industries while the gases yielded from the process can be used to supply about 75% of the energy requirements of the pyrolysis process.  The pyrolysis process operates at reactor temperatures of about 400-500 degrees Celsius.

Dynamotive has two small demonstration plants.  One demonstration plant is located in Guelph, Ontario, Canada and its capacity is 66,000 dry tons of biomass a year with an energy output equivalent to 130,000 barrels of oil.  The other of its demonstration plants is located in West Lorne, Ontario, Canada.  This plant started operation in early 2005 using waste sawdust as a feedstock.  The West Lorne plant has a capacity to convert 130 tonnes of biomass into BioOil per day which, if proportional to the Guelph plant, translates to an energy-equivalent of 84,500 barrels of oil per year.  The BioOil production capacity between the two plants is estimated at around 9 MGY of BioOil, but both plants are currently operating at a fraction of their rated capacity.  However, according to a recent press release, Dynamotive has contracts in place to supply a U.S.-based client with at least nine shipments of BioOil in 2010.  Although Dynamotive has been working on a technology for converting BioOil to a transportation fuel, they have not announced plans for building such a facility

*Biochemical Ethanol - POET*

POET has over twenty years of producing conventional ethanol in 23 plants in seven states with production capability of one billion gallons of ethanol annually. POET has expanded their production capability to include cellulosic ethanol technology. POET's cellulosic technology will make ethanol from plant materials like corn stalks, switch grass, wood chips and refuse. In February 2007, POET was selected by DOE for an award totaling $80 million for federal funding for a commercial cellulosic ethanol plant, which will be located in Emmetsburg, Iowa. As such, POET will be one of the first to build a cellulosic plant on a commercial scale. POET's commercial demonstration plant is projected to produce 25 million gallons per year and start up in 2011. It will make cellulosic ethanol from plant materials such as corn cobs and perhaps other cellulosic feedstocks.

*Biochemical Ethanol – Iogen, KL Energy, DuPont Danisco, Fiberight*

Like Poet, Iogen is pursuing a biochemical cellulosic ethanol technology very similar to the biochemical pathway described in previously in Section 1.4.3 utilizing their own proprietary enzymes. Iogen opened the first commercial demonstration cellulosic ethanol plant in North America. Iogen's plant located in Ottawa, Canada has been producing cellulosic ethanol from wheat straw since 2004. Iogen has slowly been ramping up production at its 0.5 MGY plant. According to the company's website, they produced approximately 24,000 gallons in 2004 and 34,000 gallons in 2005. Production dropped dramatically in 2006 and 2007 but came back strong with 55,000 gallons in 2008. Up to the last quarter of 2009, Iogen has produced over 127,000 gallons of ethanol from their demonstration plant.

Iogen also recently became the first cellulosic ethanol producer to sell its advanced biofuel at a retail service station in Canada. Their cellulosic ethanol was blended to make E10 available for sale to the consumers at an Ottawa Shell station. Iogen also recently announced plans to build its first commercial scale plant in Prince Albert, Saskatchewan, in the 2011/2012 timeframe.

KL Energy Corporation (KL Energy), through its majority-owned Western Biomass Energy, LLC (WBE) located in Upton, WY, is designed to convert wood products and wood waste products into ethanol using a biochemical pathway similar to that described previously in Section 1.4.3. Since the end of construction in September 2007, equipment commissioning and process revisions continued until the October 2009 startup. The plant was built as a 1.5 MGY demonstration plant and was designed to both facilitate research and operate commercially. It is KL Energy's intent that WBE's future use will involve the production and sale of small but commercial-quality volumes of ethanol and lignin co-product. The company's current 2010 production goal is for WBE to generate RINs under the RFS2 program.

DuPont Danisco Cellulosic Ethanol, LLC (DDCE), a joint venture between Dupont and Danisco, is another company pursuing biochemical conversion of cellulosic material into ethanol. DDCE received funding from the State of Tennessee and the University of Tennessee to build a small 0.25 MGY demonstration plant in Vonore, TN, to pursue switchgrass-to-ethanol production. According to DDCE, construction commenced in October 2008 and the plant is now mechanically complete and currently undergoing start-up operations. The facility is scheduled to come online in January and the company hopes to operate at or around 50% of production capacity in 2010. According to the DDCE, the objective in Vonore is to validate processes and data for commercial scale-up.

Fiberight, LLC (Fiberight) is yet another company pursing cellulosic ethanol from a biochemical process, but using MSW as a feedstock. According to Fiberight, they have been operating a pilot-scale facility in Lawrenceville, VA, for three years. They have developed a proprietary process that not only fractionates MSW but biologically converts the non-recyclable portion into cellulosic ethanol and biochemicals. Fiberight recently purchased a shut down corn ethanol plant in Blairstown, IA, and plans to convert it to become MSW-to-ethanol capable. According to the company, construction is currently underway and the goal is to bring the 2 MGY demo plant online by February or March, 2010. Fiberight's long-term goal is to expand the Blairstown plant to a 5-8 MGY capacity and build other small commercial plants around the country that could convert MSW into fuel.

*Thermochemical Ethanol - Range Fuels and Enerkem*

Range Fuels produces cellulosic ethanol via a two step thermochemical process. Their technology converts biomass to syngas followed by catalytic conversion of the syngas to alcohols. Range claims that their technology is capable of producing more ethanol than other cellulosic technologies based on yields per energy input. They utilize a two step process which can use many forms of non food biomass, such as agriculture waste, wood, and corn stocks. Additionally, the technology can process feed stocks with variable water content.

In the Range process, biomass feedstock are converted by heat, pressure and steam into syngas, which is then scrubbed and cleaned before entering into the second stage. The second stage uses catalyst to convert the syngas into methanol, which are then converted in an additional reactor into ethanol. Overall, the Range process is simple as no enzymes or living organisms are used for the main conversion reactions.

Range has operated a pilot plant for over 7 years using over 20 different nonfood feedstocks. Range broke ground building its first commercial plant late in late 2008 and is expected to be operational in 2010. This plant will be located in Soperton, Georgia and is partially funded from proceeds of a DOE grant. The plant will use wood, grasses, and corn stover as feedstocks. In its initial phase, the Range plant is expected to produce 4 million gallons per year of methanol. After the company is confident in its operations, Range will begin efforts to expand the plant and add additional reaction capacity to convert the methanol to ethanol.

Enerkem is another company like Range Fuels pursuing cellulosic ethanol production via the thermochemical route. The Canadian-based company was recently announced as a recipient of a $50 million grant from DOE to build a 10 MGY woody biomass-to-ethanol plant in Pontotoc, MS. The U.S. plant is not scheduled to come online until 2012, but Enerkem is currently building a 1.3 MGY demonstration plant in Westbury, Quebec. According to the company, plant construction in Westbury started in October 2007 and the facility is currently scheduled to come online around the middle of 2010. While it's unclear at this time whether the cellulosic ethanol produced will be exported to the United States, Enerkem has expressed interest in selling its fuel commercially.

*Reforming of Sugars to Gasoline - Virent Bioreforming*

Virent is pursuing a process called “Bioforming” which functions similarly as the gasoline reforming process used in the refining industry. While refinery-based reforming raises natural gasoline’s octane value and produces organic chemicals, benzene, xylene and toluene as a byproduct, Bioforming reforms biomass-derived sugars into hydrocarbons for blending into gasoline and diesel fuel. The process however, operates at much lower temperatures and pressures than reforming used by the refining industry. The Bioforming process is being developed through a partnership with Shell, Cargill, Honda and the University of Wisconsin. Virent currently has 16 pilot plants in operation. At this stage, though, the data is limited. It appears that Bioforming is a promising technology, as production costs estimates are low in comparison to many other renewable and biomass production processes while the products are compatible with traditional petroleum stocks.

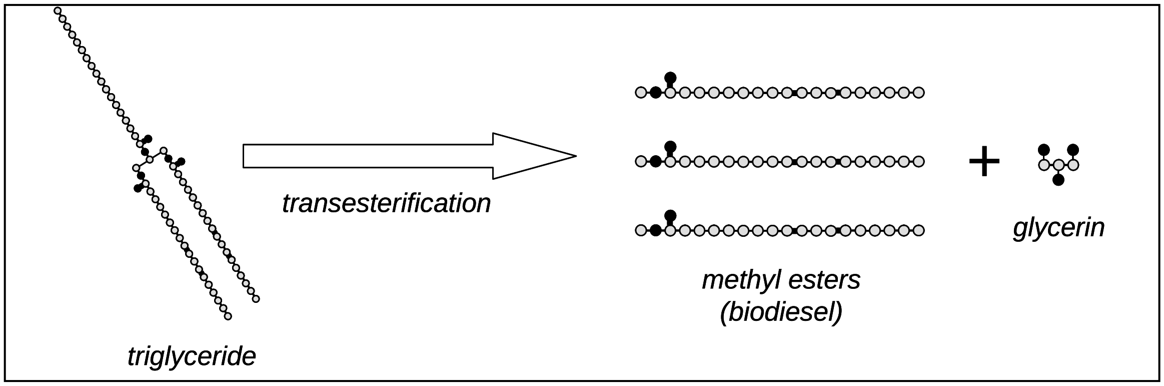
Biomass feedstocks for the Bioforming process are sugar feeds, such a corn syrup, sucrose, glycerol, sorbitol, xylose, glucose, cellulose and hemi cellulose. These are primarily converted into gasoline and diesel fuel, though other hydrocarbons such as jet fuel, LPG, benzene, toluene, xylene, hydrogen, natural gas can also be produced. Water is also produced, as the reforming process removes oxygen from the sugar feeds. The resulting properties and energy content of gasoline and diesel produced though are physically comparable to those yielded from refining industry. Variable operating costs are low because no distillation equipment is needed to separate the produced gasoline, diesel and other hydrocarbons, as these separate naturally from the aqueous solutions generated in the reforming process. The net energy costs are also low due to low operating pressures and temperatures.

### 1.4.4 Biodiesel & Renewable Diesel Production

#### 1.4.4.1 Biodiesel

Plant oils and animal fats are triglycerides, a molecule consisting of a group of three hydrocarbon chains (saturated or olefinic) linked to a three-carbon backbone via carboxylic acid esters (see Figure 1.4-9). Biodiesel is made by removing the chains from the triglyceride molecules and adding methanol to their ends to form methyl esters. Glycerin is formed as a co-product from the three-carbon backbones that remain. For relatively pure triglycerides, such as virgin plant oils, the primary reaction is catalyzed by an alkaline pH and takes place in a stirred vessel at mild temperature and pressure conditions.

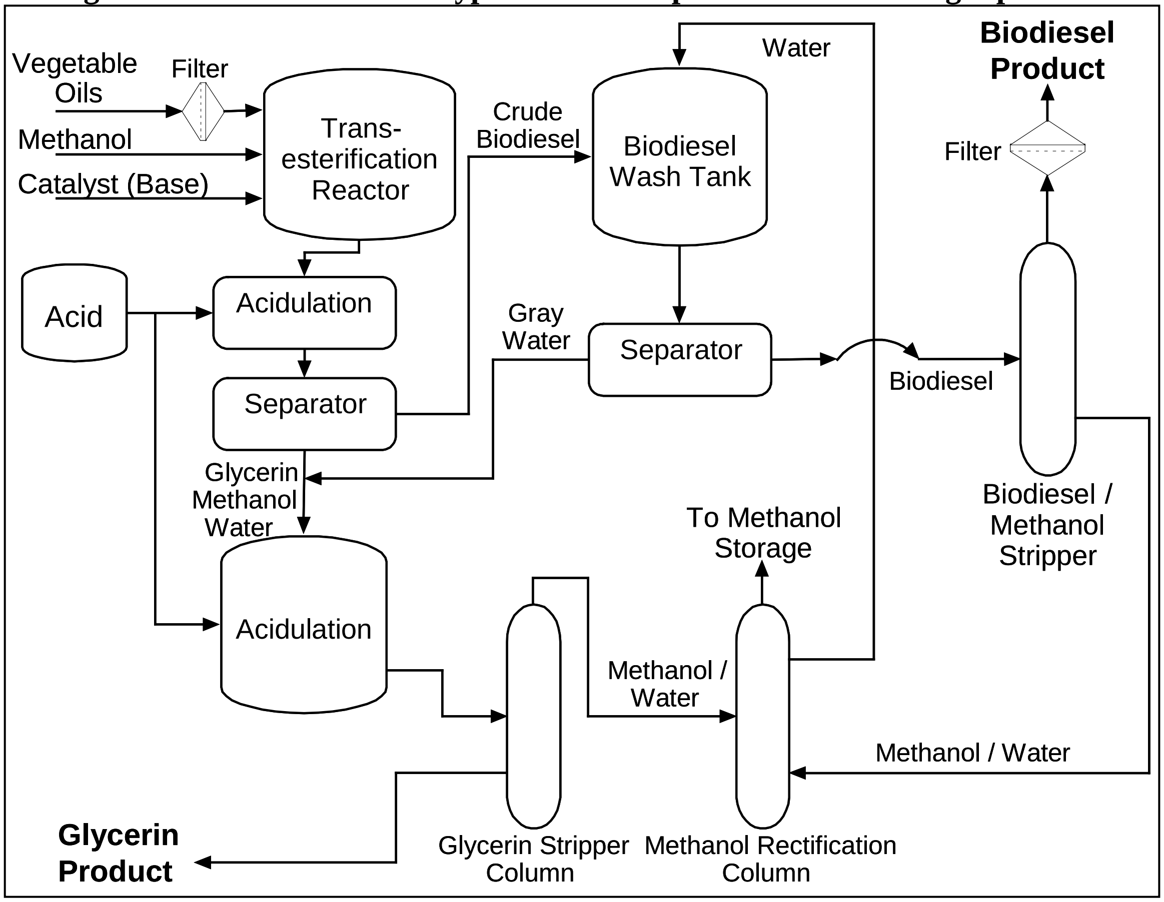
Figure 1.4-9. Overview of biodiesel conversion process



In the case of feedstocks containing more than a few percent free fatty acids (FFAs), such as rendered fats, waste greases, or corn oil extracted after ethanol production, addition of base will result in the formation of soap, an undesirable process contaminate when present above trace levels. To avoid this, these feedstocks must first undergo an acid pre-treatment step to esterify the FFAs before proceeding to the base-catalyzed triglyceride transesterification reaction. Feedstocks with small amounts of FFAs may be converted in a basic environment if the soaps can be removed from the fuel product.

Once the chemical conversions are complete, the mixture is neutralized, washed, and co-product and unreacted alcohol and catalyst are recovered. At that point the biodiesel is subjected to quality control testing and then released for sale. Figure 1.4-10 shows a process flow diagram for a typical biodiesel production process that uses virgin plant oil as feedstock; processes using waste fats or greases would include an acid esterification step upstream of the transesterification reactor shown here. Plants that also produce other oleochemicals often have distillation equipment at the end of the process capable of purifying the methyl esters to a high degree or separating them by molecular weight. These plants may use this equipment to produce a very high purity biodiesel product. We estimate that only a very small fraction of biodiesel production is distilled. [241]

**Figure 1.4-10. Schematic of typical biodiesel production from virgin plant oil**



Some differences exist between large and small plants that are worth mentioning given the very wide range of plant capacities existing in this industry. Larger plants (greater than 10 million gallons per year) are more likely to employ continuous flow processes, which afford certain efficiencies of scale and steady-state operation. On the other hand, small plants (less than one million gallons per year) are most likely to produce fuel batch-by-batch, which may give them more flexibility to change feedstock types or slow output on short notice. Smaller plants are less likely to be able to afford an on-site laboratory or quality control specialist, which may cause them hardship as fuel quality standards tighten and/or are more stringently enforced. Third-party labs exist for this purpose, but they pose challenges such as significant per-test costs and multi-day turnaround times that require holding of product batches until results are received.

The biodiesel production process is relatively simple and economical, and there is already sufficient existing U.S. capacity to produce all the biodiesel required to meet the biomass-based diesel standard put forth in EISA. Thus, we do not expect large changes in the process technology used to make biodiesel going into the future. That said, it is worth noting some potential changes as existing plants strive to comply with changing fuel quality standards, or as new plants are occasionally built to take advantage of specific market niches.

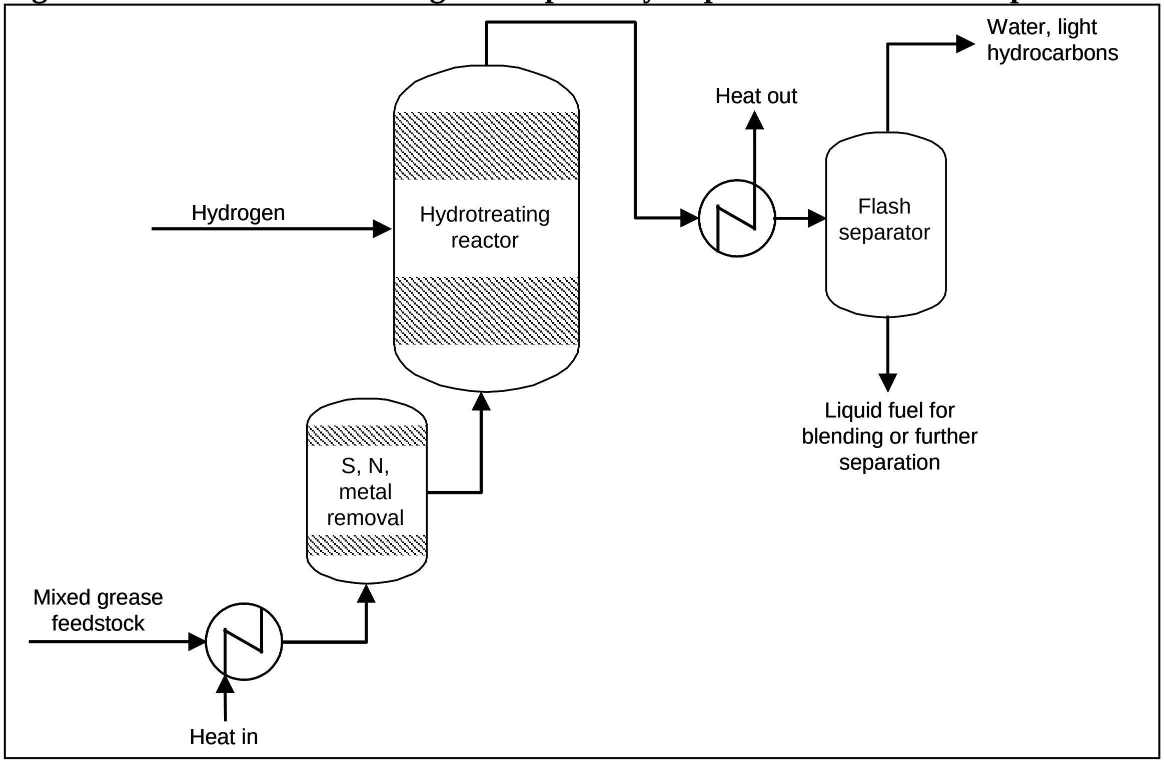
One such change may be an increase in distillation of biodiesel. EPA requires biodiesel to meet the ASTM D-6751 specification for B100 in order to be legally blended into diesel fuel for use in vehicles. Earlier this year, ASTM amended this specification to require a cold filter plugging test, which effectively mandates very low levels of FFAs, sterol glucosides, and partially-converted triglycerides in the finished biodiesel. There are a variety of process parameters a biodiesel producer can adjust to reduce the levels of these compounds in the finished fuel, but one very effective way to ensure a high purity product is through distillation. At this time it is unclear to what extent distillation will be relied upon for compliance with the amended biodiesel specification. An increase in distillation would increase per-gallon energy inputs to the process significantly.

Some industry forecasts suggest animal fats and waste greases will make up an increasing share of biodiesel feedstocks due to their lower costs and lower upstream GHG impacts. Because most fats and greases contain significant levels of FFAs, this shift will cause more plants to use acid pre-treatment, increasing process complexity and per-gallon energy use.

#### 1.4.4.2 *Renewable Diesel*

The renewable diesel production process converts vegetable oils and animal fats into diesel fuel using thermal depolymerization, which is similar to hydrotreating used in petroleum refining to remove sulfur. The process uses hydrogen and catalyst to remove oxygen from the triglyceride molecules in the feedstocks oils via a decarboxylation and hydro-oxygenation reaction, yielding some light petroleum products and water as co-products. The reactions can also saturate the olefin bonds in the feedstock oils, converting them to paraffins; additional steps can also be taken to isomerize a portion of the paraffins to create fuels with varying properties. All of these reactions consume significant amounts of hydrogen. The yield of these reactions to the primary product (diesel) depends on the process conditions, as some of the carbon backbone of the oils can be cracked to naphtha and lighter products with higher severity. For our analysis we assume approximately 90% yield to diesel, with the remainder split between light fuel gas and naphtha. Figure 1.4-11 shows a flow diagram of the primary steps of renewable diesel production.

**Figure 1.4-11. Process flow diagram of primary steps in renewable diesel production**



Renewable diesel can be produced either at a stand-alone facility or within the boundaries of an existing petroleum refinery. For the stand-alone facility, feedstock is brought in and finished fuel is transported out to market. This type of facility may be co-located with a rendering facility or a chemical operation with excess hydrogen to minimize feedstock transportation and storage costs. For production within the boundaries of a refinery, the feed material may either be processed in a segregated unit (new or revamped), or co-processed with petroleum in an existing unit. In any case, the feedstock will require pre-treatment in a unit that removes contaminates such as sulfur, nitrogen, and trace metals that may poison hydrotreating catalysts.

For a period during 2007 and 2008, ConocoPhilips produced some (300-500 bbl/day) renewable diesel at their Borger, Texas, refinery from beef tallow generated by Tyson Foods, Inc. in Amarillo, Texas. [242] In fall of 2008, Dynamic Fuels, LLC (a joint venture of Syntroleum Corp. and Tyson Foods, Inc.) announced construction of a 75 million gallon per year plant (5,000 bbl/day) in Geismar, Louisiana, that will use Tyson meat processing fats as feedstock to Syntroleum's Bio-Synfining process. Start-up is scheduled for mid-2010, with the primary product being high-quality diesel fuel that will be fungible within the existing petroleum supply system. [243] This facility plans to utilize supplies of hydrogen available in the industrial area where it will be located, as well as rail and shipping infrastructure already in place nearby. [244]

Syntroleum Corp was founded in 1984 and holds a number of patents in gas-to-liquids and biomass-to-liquids conversion processes. One such process has the trade name Synfining, and upgrades Fischer-Tropsch paraffins to isomers with properties more favorable for diesel fuel.

They have further adapted this process to use a variety of fats and oils as feedstocks, calling it Bio-Synfining. It is this technology that will be used in the Geismar facility.

Looking internationally, the Finnish company Neste Oil began operating a 3,200 bbl/day process in Finland in 2007 to convert vegetable oils into renewable diesel. This company has plans to construct similar facilities in Singapore and the Netherlands by 2010, and eventually plans to bring on-line plants that will convert biomass to liquid fuels using gasification. [245]

Since thermochemical production of hydrocarbon fuels from fats and biomass is a relatively new endeavor to conduct on a commercial scale, we expect continued innovation and fine-tuning of the technology as these processes evolve from their roots in Fischer-Tropsch and petroleum hydrotreating processes. (This discussion ties in with cellulosic diesel in Section 1.4.3.2.)

## 1.5 Biofuel Industry Characterization & Projected Growth

In this section we discuss the current state of the biofuel industry and how production might grow in the future under the RFS2 program based on our volume assumptions. The bulk of the discussion focuses on corn ethanol, imported sugarcane-based ethanol and conventional FAME-based biodiesel, today's most established U.S. biofuel sources. However, we also discuss renewable diesel, cellulosic diesel, algae-based biodiesel and other up-and-coming second generation biofuels that are likely to develop during the course of the RFS2 program.

In the subsections that follow, we'll discuss corn ethanol and how the industry might look once it finishes building out production capacity to 15 billion gallons and employs more advanced processing technologies. From there we will discuss the availability of imported ethanol from Brazil and Caribbean Basin Initiative (CBI) countries to help meet the advanced biofuel standard. Domestic sugarcane- and sweet sorghum-based ethanol plants could also contribute to meeting the advanced biofuel standard in EISA. Following this discussion, we will characterize the present state of the cellulosic biofuel industry and talk about the potential timeline for commercialization based on projected industry plans and technological breakthroughs aided by state and federal grants, tax incentives, and loan guarantee programs. As part of this discussion we will describe our assessment of the cellulosic industry in the context of setting the standard for 2010. Finally, we will conclude our industry characterization by discussing the present state of the biomass-based diesel industry and how we expect biodiesel production to grow in the future along with renewable diesel and algae-based biodiesel.

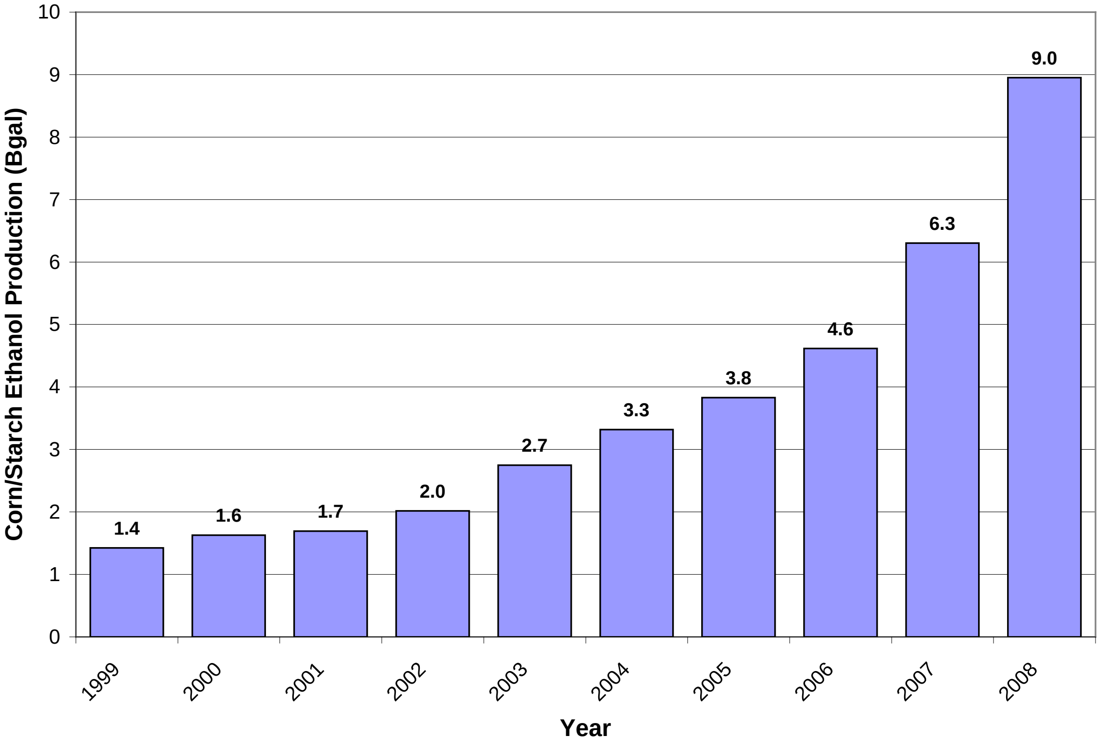
### 1.5.1 Corn Ethanol

The majority of domestic biofuel production currently comes from plants processing corn and other similarly-processed grains in the Midwest. However, there are a handful of plants located outside the Corn Belt and a few plants processing simple sugars from food or beverage waste. In this subsection, we will talk about the present state of the corn ethanol industry and how we expect things might change in the future under the RFS2 program.

### 1.5.1.1 Historic/Current Production

The United States is currently the largest ethanol producer in the world. In 2008, the U.S. produced nine billion gallons of fuel ethanol for domestic consumption, the majority of which came from locally-grown corn.[Z,246] The nation is currently on track for producing over 10 billion gallons by the end of 2009.[AA,247] Although the U.S. ethanol industry has been in existence since the 1970s, it has rapidly expanded in recent years due to the phase-out of methyl tertiary butyl ether (MTBE), elevated crude oil prices, state mandates and tax incentives, the introduction of the Federal Volume Ethanol Excise Tax Credit (VEETC)[BB], the implementation of the existing RFS1 program[CC] and the new volume requirements established under EISA[248]. As shown in Figure 1.5-1, U.S. ethanol production has grown exponentially over the past decade.

**Figure 1.5-1.**
**Historical Growth in U.S. Corn/Starch Ethanol Production**[249]



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[Z] Based on historical transportation ethanol use less imports reported by EIA.

[AA] Based on projected transportation ethanol use less imports reported by EIA. Actual year-end data for 2009 for unavailable at the time of this FRM assessment.

[BB] On October 22, 2004, President Bush signed into law H.R. 4520, the American Jobs Creation Act of 2004 (JOBS Bill), which created the Volumetric Ethanol Excise Tax Credit (VEETC). The $0.51/gal ethanol blender credit replaced the former fuel excise tax exemption, blender's credit, and pure ethanol fuel credit. However, the 2008 Farm Bill modified the alcohol credit so that corn ethanol gets a reduced credit of $0.45/gal and cellulosic biofuel gets a credit of $1.01/gal.

[CC] On May 1, 2007, EPA published a final rule (72 FR 23900) implementing the Renewable Fuel Standard (RFS) required by the Energy Policy Act of 2005. The RFS requires that 4.0 billion gallons of renewable fuel be blended into gasoline/diesel by 2006, growing to 7.5 billion gallons by 2012.

As of November 2009 there were 180 corn/starch ethanol plants operating in the U.S. with a combined production capacity of approximately 12 billion gallons per year.[DD,250] This does not include idled ethanol plants, discussed later in this subsection. The majority of today's ethanol production (91.5% by volume) is produced exclusively from corn. Another 8.3% comes from plants processing a blend of corn and/or similarly-processed grains (milo, wheat, or barley). The remainder comes from small plants processing waste beverages or other waste sugars and starches. A summary of U.S. ethanol production by feedstock is presented in Table 1.5-1.

**Table 1.5-1.**
**Current Corn/Starch Ethanol Production Capacity by Feedstock**

| Plant Feedstock (Primary Listed First) | Capacity MGY | % of Capacity | No. of Plants | % of Plants |
|---|---:|---:|---:|---:|
| Corn[a] | 10,994 | 91.5% | 155 | 86.1% |
| Corn, Milo[b] | 817 | 6.8% | 15 | 8.3% |
| Corn, Wheat | 130 | 1.1% | 1 | 0.6% |
| Milo | 3 | 0.0% | 1 | 0.6% |
| Wheat, Milo | 50 | 0.4% | 1 | 0.6% |
| Waste Beverages[c] | 20 | 0.2% | 5 | 2.8% |
| Waste Sugars & Starches[d] | 7 | 0.1% | 2 | 1.1% |
| **Total** | **12,020** | **100%** | **180** | **100%** |

[a] Includes one facility processing seed corn, one facility operating a pilot cellulosic butanol plant, one facility with plans to build a pilot cellulosic ethanol plant, and two facilities with plans to build small commercial cellulosic ethanol plants in the future.

[b] Includes one facility processing a small amount of molasses in addition to corn and milo.

[c] Includes two facilities processing brewery waste.

[d] Includes one facility processing potato waste that intends to add corn in the future.

As shown in Table 1.5-1, of the 180 operating plants, 173 process corn and/or other similarly processed grains. Of these facilities, 162 utilize dry-milling technologies and the remaining 11 plants rely on wet-milling processes. Dry mill ethanol plants grind the entire kernel and generally produce only one primary co-product: distillers' grains with solubles (DGS). The co-product is sold wet (WDGS) or dried (DDGS) to the agricultural market as animal feed. However, there are a growing number of plants using front-end fractionation to produce food-grade corn oil or back-end extraction to produce fuel-grade corn oil for the biodiesel industry. A company called GreenShift has corn oil extraction facilities located at five

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[DD] Our November 2009 corn/starch ethanol industry characterization was based on a variety of sources including plant lists published online by the Renewable Fuels Association and Ethanol Producer Magazine, information from ethanol producer websites including press releases, and follow-up correspondence with producers. The baseline does not include ethanol plants whose primary business is industrial or food-grade ethanol production nor does it include plants that might be located in the Virgin Islands or U.S. territories. Where applicable, current/historic production levels have been used in lieu of nameplate capacities to estimate production capacity.

ethanol plants in Michigan, Indiana, New York and Wisconsin.[EE,251] Collectively, these facilities are designed to extract in excess of 7.3 million gallons of corn oil per year. Primafuel Solutions is another company offering corn oil extraction technologies to make existing ethanol plants more sustainable. For more information on corn oil extraction and other advanced technologies being pursued by today's corn ethanol industry, refer to Section 1.4.1 of the RIA

In contrast to traditional dry mill plants, wet mill facilities separate the kernel prior to processing into its component parts (germ, fiber, protein, and starch) and in turn produce other co-products (usually gluten feed, gluten meal, and food-grade corn oil) in addition to DGS. Wet mill plants are generally more costly to build but are larger in size on average. As such, 11.4% of the current grain ethanol production comes from the 11 wet mill facilities listed in Table 1.5-2.

**Table 1.5-2.**
**Existing Wet Mill Corn Ethanol Plants**

| **Ethanol Plant/Company** | **Location** | **Capacity MGY** | **% of Tot Capacity** |
|---|---|---:|---:|
| Archer Daniels Midland[a] | Cedar Rapids, IA | 250 | 2.1% |
| Archer Daniels Midland[a] | Clinton, IA | 190 | 1.6% |
| Archer Daniels Midland[a] | Columbus, NE | 95 | 0.8% |
| Archer Daniels Midland[a] | Decatur, IL | 290 | 2.4% |
| Archer Daniels Midland[a] | Marshall, MN | 40 | 0.3% |
| Aventine Renewable Energy | Pekin, IL | 100 | 0.8% |
| Cargill, Inc. | Eddyville, IA | 35 | 0.3% |
| Cargill, Inc. | Blair, NE | 185 | 1.5% |
| Grain Processing Corp | Muscatine, IA | 20 | 0.2% |
| Penford Products | Cedar Rapids, IA | 45 | 0.4% |
| Tate & Lyle | Loudon, TN | 126 | 1.0% |
| **Total** | | **1,376** | **11.4%** |

[a] Estimated plant capacities.

The remaining seven ethanol plants process waste beverages or sugars/starches and operate differently than their grain-based counterparts. These small production facilities do not require milling and operate a simpler enzymatic fermentation process. Due to their limited feedstock supplies and niche markets, these plants have much smaller ethanol production capacities than traditional dry and wet mill corn ethanol plants. A summary of today's average ethanol plant size by processing technology is found in Table 1.5-3 below.

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[EE] Two plants in Michigan and one in each of the other three states. All company information based on GreenShift's Q2 2009 SEC filing.

**Table 1.5-3.**
**Average Corn/Starch Plant Sizes**

| Processing Technology | Capacity MGY | % of Capacity | No. of Plants | % of Plants | Avg. Size MGY |
|---|---|---|---|---|---|
| Dry Milling[a] | 10,618 | 88.3% | 162 | 90.0% | 65.5 |
| Wet Milling[a] | 1,376 | 11.4% | 11 | 6.1% | 125.1 |
| Other[b] | 26 | 0.2% | 7 | 3.9% | 3.8 |
| **Total** | **12,020** | **100.0%** | **180** | **100.0%** | **66.8** |

[a] Includes a total of three corn ethanol plants with plans to process cellulosic feedstocks in the future. To the extent that cellulosic facilities are integrated with existing processes, these plants will need additional front-end technology to supplement existing dry milling equipment.
[b] Facilities that do not process traditional grain-based crops and thus do not require milling. Includes plants processing waste beverages or sugars and starches.

Ethanol production is a relatively resource-intensive process that requires the use of water, electricity, and steam. Steam needed to heat the process is generally produced on-site or by other dedicated boilers.[FF] The ethanol industry relies primarily on natural gas. Of today's 180 ethanol production facilities, an estimated 151 burn natural gas[GG] (exclusively), three burn a combination of natural gas and biomass, one burns natural gas and coal (although natural gas is the primary fuel), one burns a combination of natural gas, landfill biogas and wood, and two burn natural gas and syrup from the process. We are aware of 17 plants that burn coal as their primary fuel and one that burns a combination of coal and biomass.[HH] Our research suggests that three corn ethanol plants rely on a combination of waste heat and natural gas and one plant does not have a boiler and relies solely on waste heat from a nearby power plant. Overall, our research suggests that 27 plants currently utilize cogeneration or combined heat and power (CHP) technology, although others may exist.[II,252] CHP is a mechanism for improving overall plant efficiency. Whether owned by the ethanol facility, their local utility, or a third party, CHP facilities produce their own electricity and use the waste heat from power production for process steam, reducing the energy intensity of ethanol production.[JJ] A summary of the energy sources and CHP technology utilized by today's ethanol plants is found in Table 1.5-4.

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[FF] Some plants pull steam directly from a nearby utility.

[GG] Facilities were assumed to burn natural gas if the plant boiler fuel was unspecified or unavailable on the public domain.

[HH] Includes corrections from NPRM based on new information obtained on Cargill plants and Blue Flint ethanol plant.

[II] CHP assessment based on information provided by EPA's Combined Heat and Power Partnership, literature searches and correspondence with ethanol producers.

[JJ] For more on CHP technology, refer to Section 1.4.1.3.

### Table 1.5-4.
### Current Corn/Starch Ethanol Production Capacity by Energy Source

| **Plant Energy Source (Primary Listed First)** | **Capacity MGY** | **% of Capacity** | **No. of Plants** | **% of Plants** | **CHP Tech.** |
|---|---:|---:|---:|---:|---:|
| Coal[a] | 1,758 | 14.6% | 17 | 9.4% | 8 |
| Coal, Biomass | 50 | 0.4% | 1 | 0.6% | 0 |
| Natural Gas[b] | 9,627 | 80.1% | 151 | 83.9% | 13 |
| Natural Gas, Biomass[c] | 115 | 1.0% | 3 | 1.7% | 1 |
| Natural Gas, Coal | 35 | 0.3% | 1 | 0.6% | 1 |
| Natural Gas, Landfill Biogas, Wood | 110 | 0.9% | 1 | 0.6% | 0 |
| Natural Gas, Syrup | 101 | 0.8% | 2 | 1.1% | 0 |
| Waste Heat[d] | 50 | 0.4% | 1 | 0.6% | 1 |
| Waste Heat[d], Natural Gas | 175 | 1.5% | 3 | 1.7% | 3 |
| **Total** | **12,020** | **100.0%** | **180** | **100.0%** | **27** |

[a] Includes four plants that are permitted to burn biomass, tires, petroleum coke, and wood waste in addition to coal and one facility that intends to switch to biomass in the future.

[b] Includes two facilities that might switch to biomass, one facility that intends to burn thin stillage and biogas, and two facilities that were once considering switching to coal in the future.

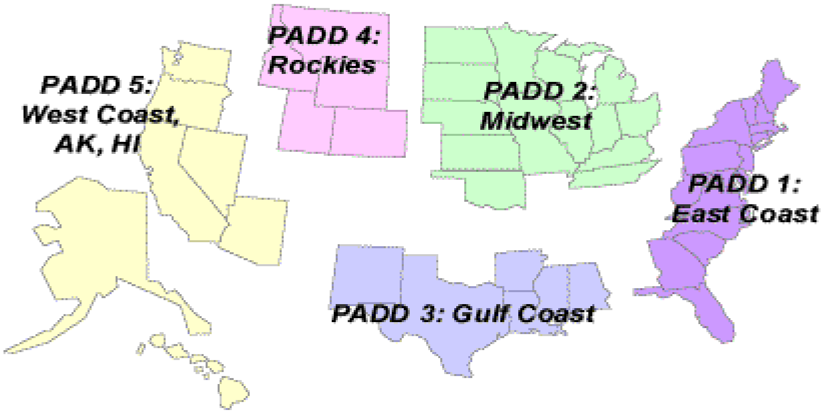
[c] Includes one facility processing bran in addition to natural gas.

[d] Waste heat from utility partnerships.

During the ethanol fermentation process, large amounts of carbon dioxide ($CO_2$) gas are released. In some plants, the $CO_2$ is vented into the atmosphere, but where local markets exist, it is captured, purified, and sold to the food processing industry for use in carbonated beverages and flash-freezing applications. We are currently aware of 40 fuel ethanol plants that recover $CO_2$ or have facilities in place to do so. According to Airgas, a leading gas distributor, the U.S. ethanol industry currently recovers 2 to 2.5 million tons of $CO_2$ per year which translates to about 5-7% of all the $CO_2$ produced by the industry.[253]

Since the majority of ethanol is made from corn, it is no surprise that most of the plants are located in the Midwest near the Corn Belt. Of today's 180 ethanol production facilities, 163 are located in the 15 states comprising PADD 2. For a map of the Petroleum Administration for Defense Districts or PADDs, refer to Figure 1.5-2.

**Figure 1.5-2.**
**Petroleum Administration for Defense Districts**



As a region, PADD 2 accounts for over 94% (or 11.3 billion gallons) of today's estimated ethanol production capacity, as shown in Table 1.5-5.

**Table 1.5-5.**
**Current Corn/Starch Ethanol Production Capacity by PADD**

| PADD | Capacity MGY | % of Capacity | No. of Plants | % of Plants |
|---|---|---|---|---|
| PADD 1 | 150 | 1.3% | 3 | 1.7% |
| PADD 2 | 11,329 | 94.2% | 163 | 90.6% |
| PADD 3 | 294 | 2.4% | 4 | 2.2% |
| PADD 4 | 152 | 1.3% | 7 | 3.9% |
| PADD 5 | 95 | 0.8% | 3 | 1.7% |
| **Total** | **12,020** | **100.0%** | **180** | **100.0%** |

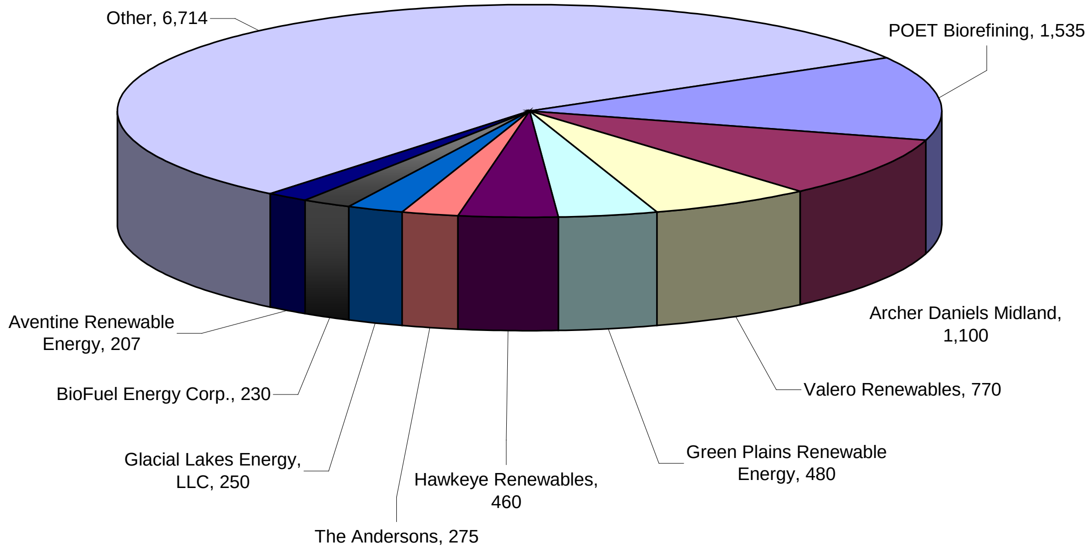
Leading the Midwest in ethanol production are Iowa, Nebraska, Illinois, Minnesota, and South Dakota. Together, these five states' 109 ethanol plants account for over two-thirds (or about 8.2 billion gallons) of the nation's ethanol production capacity. However, although the majority of ethanol production comes from PADD 2, there are a growing number of plants situated outside the traditional Corn Belt. Our November 2009 industry assessment indicates that Arizona, California, Colorado, Georgia, Idaho, Mississippi, New York, Oklahoma, Oregon, Texas and Wyoming all have one or more operational ethanol plants. Some of these facilities ship in feedstocks (namely corn) from the Midwest, others rely on locally grown/produced feedstocks, while others rely on a combination of the two. A summary of the online ethanol production capacity by state is presented in Table 1.5-6.

**Table 1.5-6.**
**Current Corn/Starch Ethanol Production Capacity by State**

| State | Capacity MGY | % of Capacity | No. of Plants | % of Plants |
|---|---|---|---|---|
| Iowa | 3,214 | 26.7% | 39 | 21.7% |
| Nebraska | 1,560 | 13.0% | 23 | 12.8% |
| Illinois | 1,342 | 11.2% | 13 | 7.2% |
| Minnesota | 1,113 | 9.3% | 20 | 11.1% |
| South Dakota | 987 | 8.2% | 14 | 7.8% |
| Indiana | 716 | 6.0% | 9 | 5.0% |
| Wisconsin | 529 | 4.4% | 9 | 5.0% |
| Kansas | 439 | 3.6% | 11 | 6.1% |
| North Dakota | 355 | 3.0% | 5 | 2.8% |
| Ohio | 320 | 2.7% | 5 | 2.8% |
| Missouri | 261 | 2.2% | 6 | 3.3% |
| Texas | 240 | 2.0% | 3 | 1.7% |
| Tennessee | 236 | 2.0% | 2 | 1.1% |
| Michigan | 217 | 1.8% | 4 | 2.2% |
| Colorado | 138 | 1.1% | 5 | 2.8% |
| Georgia | 100 | 0.8% | 2 | 1.1% |
| Mississippi | 54 | 0.4% | 1 | 0.6% |
| New York | 50 | 0.4% | 1 | 0.6% |
| Arizona | 50 | 0.4% | 1 | 0.6% |
| Kentucky | 40 | 0.3% | 2 | 1.1% |
| Oregon | 40 | 0.3% | 1 | 0.6% |
| Wyoming | 9 | 0.1% | 1 | 0.6% |
| California | 5 | 0.0% | 1 | 0.6% |
| Idaho | 5 | 0.0% | 1 | 0.6% |
| Oklahoma | 2 | 0.0% | 1 | 0.6% |
| **Total** | **12,020** | **100.0%** | **180** | **100.0%** |

The U.S. ethanol industry is currently comprised of a mixture of company-owned plants and locally-owned farmer cooperatives (co-ops). The majority of today's ethanol production facilities are company-owned and, on average, these plants are larger in size than farmer-owned co-ops. Accordingly, these facilities account for about 80% of today's online ethanol production capacity.[254] Furthermore, nearly 30% of the total domestic product comes from 40 plants owned by just three different companies – POET Biorefining, Archer Daniels Midland (ADM), and Valero Renewables. For a summary of ethanol production capacity by company, refer to Figure 1.5-3 below.

**Figure 1.5-3.**
**Current Corn/Starch Ethanol Production Capacity by Company**



Valero entered the ethanol industry in March of 2009 when it acquired seven ethanol plants from former ethanol giant, Verasun. The oil company currently has agreements in place to purchase three more ethanol plants that would bring the company's ethanol production capacity to 1.1 billion gallons per year.[KK,255] However, ethanol plants are much smaller than petroleum refineries. Valero's smallest petroleum refinery in Ardmore, OK has about twice the throughput of all its ethanol plants combined.[256] Still, as obligated parties under RFS1 and RFS2, the refining industry continues to show increased interest in biofuels. Suncor and Murphy Oil recently joined Valero as the second and third oil companies to purchase idled U.S. ethanol plants. Many refiners are also supporting the development of cellulosic biofuels and algae-based biodiesel.

### 1.5.1.2 Forecasted Production Under RFS2

As highlighted earlier, domestic ethanol production is projected to grow to over 10 billion gallons in 2009. And with over 12 billion gallons of capacity online as of November 2009, ethanol production should continue to grow in 2010, provided plants continue to produce at or above today's production levels. In addition, despite current market conditions (i.e., poor ethanol margins), the ethanol industry is expected to grow in the future under the RFS2 program. Although there is not a set corn ethanol requirement, EISA allows for 15 billion gallons of the 36-billion gallon renewable fuel standard to be met by conventional biofuels. We expect that

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[KK] Valero recently announced that it has purchase agreements in place to acquire the last two Verasun plants in Linden, IN and Bloomington, OH and the former Renew Energy plant in Jefferson Junction, WI.

corn ethanol will fulfill this requirement, provided it is more cost competitive than imported ethanol or cellulosic biofuel in the marketplace.

In addition to the 180 aforementioned corn/starch ethanol plants currently online, 27 plants are presently idled.[LL] Some of these are smaller ethanol plants that have been idled for quite some time, whereas others are in a more temporary "hot idle" mode, ready to be restarted. In response to the economic downturn, a number of ethanol producers have idled production, halted construction projects, sold off plants and even filed for Chapter 11 bankruptcy protection. Some corn ethanol companies have exited the industry all together (e.g., Verasun) whereas others are using bankruptcy as a means to protect themselves from creditors as they restructure their finances with the goal of becoming sustainable.

Crude oil prices are expected to increase in the future making corn ethanol more economically viable. According to EIA's AEO 2009, crude oil prices are projected to increase from about $80/barrel (today's price) to $116/barrel by 2022.[257] As oil and gas prices rebound, we expect that the biofuels industry will as well. Since our April 2009 industry assessment used for the NPRM, at least nine corn ethanol plants have come back online.

For analysis purposes, we assumed that all 27 idled corn/starch ethanol plants would resume operations by 2022 under the RFS2 program. We also assumed that a total of 11 new ethanol plants and two expansion projects currently under construction or in advanced stages of planning would come online.[258] This includes two large dry mill expansion projects currently underway at existing ADM wet mill plants and two planned combination corn/cellulosic ethanol plants that received funding from DOE. While several of these projects are delayed or on hold at the moment, we expect that these facilities (or comparable replacement projects) would eventually come online to get the nation to approximately 15 billion gallons of corn ethanol production capacity as shown below in Table 1.5-7.

**Table 1.5-7.**
**Potential Corn/Starch Ethanol Industry Expansion Under RFS2**

| | Plants Currently Online | Idled Plants[a] | Under Construction[b] | Planned Exp. or DOE-Funded Projects[c] | Total |
|---|---|---|---|---|---|
| **Plant Capacity (MGY)** | **12,020** | **1,440** | **1,301** | **166** | **14,927** |
| **No. of Plants** | **180** | **27** | **10 new** | **1 new, 2 exp** | **218** |

[a] Assumes all idled plants come back online in the future.

[b] Includes construction projects that are currently on hold. Considers two dry mill expansion projects currently underway at existing ADM wet mill sites to be new plants.

[c] Includes an expansion project at an existing corn ethanol plant and two planned combination corn/cellulosic ethanol plants that received funding from DOE.

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[LL] Based on our November 2009 corn/starch ethanol industry characterization. We are aware of at least one plant that has come back online since then.

While theoretically it only takes 12-18 months to build a corn ethanol plant[MM], the rate at which new plant capacity comes online will be dictated by market conditions, which will in part be influenced by the RFS2 requirements.  As explained in Section 1.2.2, today's program will create a growing demand for corn ethanol reaching 15 billion gallons by 2016.  However, it is possible that market conditions could drive demand even higher.  Whether the nation produces additional corn ethanol is uncertain and will be determined by feedstock availability/pricing, crude oil pricing, and the relative ethanol/gasoline price relationship.  To measure the impacts of the RFS2 program, we assumed that corn ethanol production would not exceed 15 billion gallons.  We also assumed that all growth would come from new plants or plant expansion projects (in addition to idled plants being brought back online).  However, it is possible that some of the required growth could come from minor process improvements (e.g., debottlenecking) at existing facilities.  Allowing a 5% tolerance on the baseline volume for grandfathering facilities (per §80.1403) could promote such growth.

Once the aforementioned capacity expansion is complete, we estimate that there will be 218 corn/starch ethanol plants operating in the U.S. with a combined production capacity of around 15 billion gallons per year.  Much like today's ethanol industry, the overwhelming majority of new plant capacity (almost 88% by volume) is expected to come from corn-fed plants.  Another 12% is forecasted to come from plants processing a blend of corn and/or other grains, and a tiny capacity increase is projected to come from an idled cheese whey plant coming back online.  A summary of the forecasted ethanol production by feedstock under the RFS2 program is found in Table 1.5-8.

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[MM] For more information on our estimated plant build rates, refer to Section 1.5.3.4.

### Table 1.5-8.
### Projected RFS2 Ethanol Production Capacity by Feedstock

| Plant Feedstock (Primary Listed First) | Additional Production | | Total RFS2 Estimate | |
|---|---|---|---|---|
| | Capacity MGY | No. of Plants | Capacity MGY | No. of Plants |
| Barley | 65 | 1 | 65 | 1 |
| Corn[a] | 2,549 | 30 | 13,543 | 185 |
| Corn, Milo[b] | 173 | 3 | 990 | 18 |
| Corn, Wheat | 0 | 0 | 130 | 1 |
| Corn, Wheat, Milo | 110 | 2 | 110 | 2 |
| Corn, Whey | 7 | 1 | 7 | 1 |
| Milo | 0 | 0 | 3 | 1 |
| Wheat, Milo | 0 | 0 | 50 | 1 |
| Cheese Whey | 3 | 1 | 3 | 1 |
| Waste Beverages[c] | 0 | 0 | 20 | 5 |
| Waste Sugars & Starches[d] | 0 | 0 | 7 | 2 |
| **Total** | **2,907** | **38** | **14,927** | **218** |

[a] Includes one facility processing seed corn, one facility operating a pilot cellulosic butanol plant, two facilities with plans to build pilot cellulosic ethanol plants, and three facilities with plans to build small commercial cellulosic ethanol plants.

[b] Includes one facility processing a small amount of molasses in addition to corn and milo.

[c] Includes two facilities processing brewery waste.

[d] Includes one facility processing potato waste that intends to add corn in the future.

With the exception of one facility[NN], all new corn/grain ethanol plants are expected to utilize dry milling technologies and the majority of new production is expected to come from plants burning natural gas. However, we anticipate that two manure biogas plants[OO], one biomass-fired plant, and two coal-fired ethanol plants will be added to the mix.[PP] Of these new and returning idled plants, we're aware of five facilities currently planning to use CHP technology, bringing the U.S. total to 32 as shown in Table 1.5-9.

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[NN] Tate and Lyle is currently in the process of building a 115 MGY wet mill corn ethanol plant in Fort Dodge, IA.

[OO] One manure biogas plant that is currently idled and another that was under construction but is now on hold.

[PP] The two coal fired plants are the aforementioned dry mill expansion projects currently underway at existing ADM sites. These projects commenced construction on or before December 19, 2007 and would therefore should likely be grandfathered under the RFS2 rule. For more on our grandfathering assessment, refer to Section 1.5.1.4 of the RIA.

**Table 1.5-9.**
**Projected Near-Term Corn/Starch Ethanol Production Capacity by Energy Source**

| Plant Energy Source (Primary Listed First) | Add'l Production Capacity MGY | Add'l Production No. of Plants | Total RFS2 Estimate Capacity MGY | Total RFS2 Estimate No. of Plants | Total RFS2 Estimate CHP Tech. |
|---|---|---|---|---|---|
| Biomass | 88 | 1 | 88 | 1 | 1 |
| Coal[a] | 550 | 2 | 2,308 | 19 | 10 |
| Coal, Biomass | 0 | 0 | 50 | 1 | 0 |
| Manure Biogas | 139 | 2 | 139 | 2 | 0 |
| Natural Gas[b] | 2,130 | 33 | 11,757 | 184 | 15 |
| Natural Gas, Biomass[c] | 0 | 0 | 115 | 3 | 1 |
| Natural Gas, Coal | 0 | 0 | 35 | 1 | 1 |
| Natural Gas, Landfill Biogas, Wood | 0 | 0 | 110 | 1 | 0 |
| Natural Gas, Syrup | 0 | 0 | 101 | 2 | 0 |
| Waste Heat[d] | 0 | 0 | 50 | 1 | 1 |
| Waste Heat[d], Natural Gas | 0 | 0 | 175 | 3 | 3 |
| **Total** | **2,907** | **38** | **14,927** | **218** | **32** |

[a] Includes six plants that are permitted to burn biomass, tires, petroleum coke, and wood waste in addition to coal and one facility that intends to switch to biomass in the future.

[b] Includes four facilities that might switch to biomass in the future, one facility that intends to burn thin stillage and biogas, and a total of five facilities that were once considering switching to coal in the future.

[c] Includes one facility processing bran in addition to natural gas.

[d] Waste heat from utility partnerships.

The information presented in Table 1.5-9 is based on the industry's current near-term production plans. However, we anticipate growth in advanced ethanol production technologies under the RFS2 program. Forecasted fuel prices are projected to drive corn ethanol producers to transition from conventional boiler fuels to biomass feedstocks. In addition, fossil fuel/electricity prices will likely drive a number of ethanol producers to pursue CHP technology. For more on our projected 2022 utilization of these technologies under the RFS2 program, refer to Section 1.5.1.3 of the RIA.

Under the RFS2 program, the majority of new ethanol production (almost 70% of added capacity) is expected to originate from PADD 2, close to where the corn is grown. However, there are a number of "destination" ethanol plants being built outside the Midwest in response to state production subsidies, retail pump incentives, and state mandates. A summary of the forecasted ethanol production by PADD under the RFS2 program can be found in Table 1.5-10.

**Table 1.5-10.
Projected RFS2 Corn/Starch Ethanol Production Capacity by PADD**

| PADD | Additional Production | | Total RFS2 Estimate | |
|---|---|---|---|---|
| | **Capacity MGY** | **No. of Plants** | **Capacity MGY** | **No. of Plants** |
| PADD 1 | 349 | 4 | 499 | 7 |
| PADD 2 | 2,011 | 25 | 13,340 | 188 |
| PADD 3 | 145 | 2 | 439 | 6 |
| PADD 4 | 50 | 1 | 202 | 8 |
| PADD 5 | 352 | 6 | 447 | 9 |
| **Total** | **2,907** | **38** | **14,927** | **218** |

Based on current production plans, we project that Iowa, Nebraska, Illinois, Minnesota and South Dakota will continue to dominate ethanol production with a collective production capacity of about 9.5 billion gallons per year.  Ethanol production is expected to grow in other Midwest states and there are also a growing number of plants that are being built outside the Corn Belt.  After the proposed RFS2 program is fully implemented, we estimate that more than half of the United States will have corn/starch ethanol production.  Table 1.5-11 shows our predictions of ethanol production capacity by state (from greatest to smallest) after the RFS2 program is fully implemented.

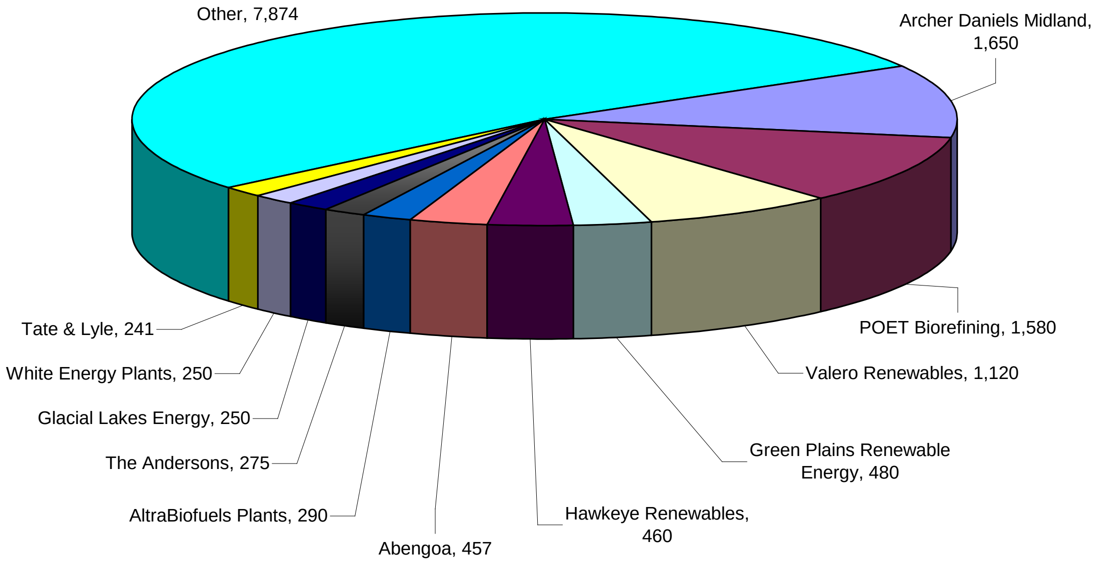
**Table 1.5-11.**
**Projected RFS2 Corn/Starch Ethanol Production Capacity by State**

| State | Additional Production | | Total RFS2 Estimate | |
|---|---|---|---|---|
| | Capacity MGY | No. of Plants | Capacity MGY | No. of Plants |
| Iowa | 545 | 3 | 3,759 | 42 |
| Nebraska | 453 | 4 | 2,013 | 27 |
| Illinois | 178 | 3 | 1,520 | 16 |
| Minnesota | 28 | 2 | 1,141 | 22 |
| South Dakota | 61 | 1 | 1,048 | 15 |
| Indiana | 286 | 3 | 1,002 | 12 |
| Kansas | 168 | 3 | 607 | 14 |
| Ohio | 224 | 3 | 544 | 8 |
| Wisconsin | 7 | 1 | 536 | 10 |
| North Dakota | 11 | 1 | 366 | 6 |
| Texas | 115 | 1 | 355 | 4 |
| Michigan | 50 | 1 | 267 | 5 |
| Missouri | 0 | 0 | 261 | 6 |
| California | 239 | 5 | 244 | 6 |
| Tennessee | 0 | 0 | 236 | 2 |
| New York | 114 | 1 | 164 | 2 |
| Oregon | 113 | 1 | 153 | 2 |
| Colorado | 0 | 0 | 138 | 5 |
| Pennsylvania | 110 | 1 | 110 | 1 |
| Georgia | 0 | 0 | 100 | 2 |
| Virginia | 65 | 1 | 65 | 1 |
| North Carolina | 60 | 1 | 60 | 1 |
| Idaho | 50 | 1 | 55 | 2 |
| Mississippi | 0 | 0 | 54 | 1 |
| Arizona | 0 | 0 | 50 | 1 |
| Kentucky | 0 | 0 | 40 | 2 |
| New Mexico | 30 | 1 | 30 | 1 |
| Wyoming | 0 | 0 | 9 | 1 |
| Oklahoma | 0 | 0 | 2 | 1 |
| **Total** | **2,907** | **38** | **14,927** | **218** |

The majority of future ethanol plants are expected to be company-owned. Of the 38 plants we are expecting to be built or brought back online under the RFS2 program, 36 are expected to be owned by corporations. The leading ethanol producers will likely continue to be

Archer Daniels Midland and POET Biorefining, each with over 1.5 billion gallons of annual corn ethanol production capacity. Valero Renewables is expected to be the third largest ethanol producer with over 1.1 billion gallons of production capacity, provided the most recent ethanol plant acquisition goes through. A summary of the projected ethanol plant ownership under the RFS2 program is found in Figure1.5-4.

**Figure 1.5-4.**
**Forecasted Corn/Starch Ethanol Production Capacity by Company**



### 1.5.1.3 Forecasted Growth in Advanced Processing Technologies

While we can get a good idea of what the ethanol industry will look like in the near term by looking at existing ethanol plants and those planned or under construction, further analysis is needed to forecast what the ethanol industry will look like in 2022. Significant changes in the primary fuel source and overall energy efficiency of ethanol production plants are likely to occur. The high price of natural gas, projected to be $7.75/MMBTU in 2022 in the EIA 2009 Annual Energy Outlook, has many ethanol plants considering alternative fuel sources. Greater biofuel availability and potential low life cycle green house gas emissions incentives may further encourage ethanol producers to transition from fossil fuels to biomass based fuels.

As ethanol plants become more efficient and require less energy, their ability to use biofuels increases. Two of the biggest drawbacks to using biofuels currently are handling and storage costs. Due to the lower density of biofuels, as compared to coal, a larger area is required to store biomass with an equivalent heating value. Handling costs are also increased as a larger volume of fuel must be moved. These negative impacts would be less significant in an ethanol plant using less energy. Lower overall energy use would also allow the energy needs of the ethanol plant to be met entirely, or to a greater extent, by waste products and locally produced biofuels. This would greatly reduce the purchase and transportation costs of the biofuels. If ethanol producers do decide to make a transition to biofuels, is likely that plants currently using natural gas would transition to biogas, and those using coal would transition to solid biomass. This is primarily due to their ability to make these transitions without investing in new boiler equipment. The same factors that may cause ethanol producers to increase biofuels usage, higher fossil fuel costs and lower lifecycle green house gas emissions, are expected to increase the number of ethanol producers using combined heat and power (CHP) technology. Projections for the primary feedstock and use of CHP technology from 2020 to 2030 are summarized in Table 1.5-12 below.

**Table 1.5-12.**[259]
**Projected Primary Fuel Sources and CHP Usage**

| | 2020 | **2022** | 2025 | 2030 |
|---|---|---|---|---|
| Natural Gas Boiler | 54% | **49%** | 42% | 31% |
| Natural Gas CHP | 11% | **12%** | 13% | 15% |
| Coal Boiler | 0% | **0%** | 0% | 0% |
| Coal CHP | 4% | **4%** | 4% | 4% |
| Biomass Boiler | 10% | **11%** | 12% | 15% |
| Biomass CHP | 9% | **10%** | 12% | 15% |
| Biogas Boiler | 12% | **14%** | 16% | 20% |

The energy efficiency of ethanol plants is also expected to change significantly. New technologies are expected to both increase the efficiency of units currently used in ethanol production, as well as provide energy-saving alternatives to conventional production practices. Increasing energy efficiency is a priority in many ethanol plants as is can dramatically increase profitability by reducing energy costs, the second highest cost of ethanol production behind raw materials. Several groups are currently working on technologies that could impact the ethanol industry. The Department of Energy's (DOE) Super Boiler program is expected to produce boilers with an efficiency of 94% by 2020. The National Electrical Manufacturers Association's (NEMA) premium efficiency motors are expected to be adopted more widely in the coming years. Electricity generation efficiency is also expected to increase at plants with CHP technology. The projected energy savings from the energy efficiency improvements to units used in conventional ethanol plants in 2022 relative to 2007 is 32.1%. The projected energy savings from 2015 to 2030 are summarized in Table 1.5-13 below.

**Table 1.5-13.[260]**
**Projected Energy Savings from Conventional Production Equipment**

| | 2007 | 2015 | 2020 | **2022** | 2025 | 2030 |
|---|---|---|---|---|---|---|
| Boiler, Efficiency | 82.0% | 86.0% | 90.0% | **91.6%** | 94.0% | 94.0% |
| Energy Savings Relative to 2007 | - | 1.2% | 8.9% | **10.5%** | 12.8% | 12.8% |
| Motor, Efficiency | 90.0% | 92.0% | 93.0% | **93.8%** | 95.0% | 95.0% |
| Energy Savings Relative to 2007 | - | 2.2% | 3.2% | **4.0%** | 5.3% | 5.3% |
| 10 MW Industrial Turbine, Efficiency | 31.0% | 33.0% | 34.0% | **34.0%** | 34.0% | 34.0% |
| Energy Savings Relative to 2007 | - | 6.1% | 8.8% | **8.8%** | 8.8% | 8.8% |

The same factors that drive ethanol producers to increase the energy efficiency of their equipment may also move them to consider energy saving changes to the ethanol production process. Several process changes, including raw starch hydrolysis, corn fractionation, corn oil extraction, and membrane separation, are likely to be adopted to varying degrees. The degree to which they are adopted will depend on many factors, including technology availability, capital cost of implementation, energy cost savings, and co-product revenue generation. A description of each of these technologies, including the challenges and benefits of their implementation, can be found in Section 1.4.1.3. The adoption of these technologies are expected to decrease the average thermal energy use of dry mill ethanol plants by 11.8% and to increase the average electrical energy use by 13.1%. These numbers are based on a plant that is drying 100% of its distillers' grains with solubles (DGS). Plants that dry less than 100% of their DGS would likely realize smaller benefits from these technologies. The projected penetration of these technologies, and the associated energy use impact, is summarized in Table 1.5-14 below.

**Table 1.5-14.[261]**
**Projected Energy Savings from Process Changes**

| Percent of all Plants Adopting Process | | | | |
|---|---|---|---|---|
| Process Improvement | 2020 | **2022** | 2025 | 2030 |
| Raw Starch Hydrolysis | 20% | **22%** | 25% | 30% |
| Corn Fractionation | 18% | **20%** | 24% | 30% |
| Corn Oil Extraction | 65% | **70%** | 70% | 70% |
| Membrane Separation | 3% | **5%** | 5% | 5% |
| Energy Reduction from Base Process (Thermal) | | | | |
| Raw Starch Hydrolysis | 16% | **16.7%** | 17% | 17% |
| Corn Fractionation | 17.6% | **17.6%** | 17.6% | 17.6% |
| Corn Oil Extraction | 5.4% | **5.4%** | 5.4% | 5.4% |
| Membrane Separation | 15.7% | **15.7%** | 15.7% | 15.7% |
| Weighted Average Savings (Thermal) | 10.3% | **11.8%** | 13.0% | 14.9% |
| Energy Reduction from Base Process (Electrical) | | | | |
| Raw Starch Hydrolysis | 0% | **0%** | 0% | 0% |
| Corn Fractionation | -29% | **-29%** | -29% | -29% |
| Corn Oil Extraction | -9.9% | **-9.9%** | -9.9% | -9.9% |
| Membrane Separation | -7.6% | **-7.6%** | -7.6% | -7.6% |
| Weighted Average Savings (Electrical) | -11.8% | **-13.1%** | -14.3% | -16.0% |

Another factor that plays a significant role in determining the energy usage of ethanol plants is the treatment of the main co-product of the dry mill ethanol production process, distillers' grains with solubles (DGS). The DGS, which is most often sold as feed for cattle, poultry, or swine, can be sold either dry or wet. Wet distillers' grain with solubles (WDGS) can often only be sold locally, as it is difficult to transport and is susceptible to spoilage. Drying the DGS avoids these problems and allows the DGS to be sold in a much wider market; however drying the DGS is an energy intensive process. USDA models suggest that 40.4% of the thermal energy used in an ethanol plant that produces dry DGS is used in the drying process. Plants that do not dry their DGS, or dry only a portion of it, could experience energy savings up to 40.4%. According to a recent industry survey, 37% of all DGS produced by the dry mill ethanol industry is sold wet. We have assumed that this percentage remains constant through 2022 for our energy use projections.

Combining the impacts of these four factors (primary fuel sources, energy savings from efficiency improvements, new technology and process changes, and DGS drying rates) allows us to project the average energy usage of a dry mill ethanol plant in 2022. Table 1.5-15 below outlines the projected average energy usage of dry mill ethanol plants in 2022. The first two lines take into account the projected primary fuel types and energy efficiency improvements. The next two lines adjust the totals to include new technologies and process changes. Finally, the total is calculated by weighting the values for dry and wet DGS according to the production ratio we expect in 2022 (63% dry DGS, 37% wet DGS)[QQ].

**Table 1.5-15**
**2022 Dry Mill Ethanol Plant Average Energy Usage**

| | Thermal Energy | Electrical Energy |
|---|---|---|
| Dry DGS, includes efficiency improvements | 28,977 BTU/Gal | 1,515 BTU/Gal |
| Wet DGS, includes efficiency improvements | 17,271 BTU/Gal | 1,515 BTU/Gal |
| Dry DGS, includes process changes | 25,570 BTU/Gal | 1,714 BTU/Gal |
| Wet DGS, includes process changes | 16,255 BTU/Gal | 1,714 BTU/Gal |
| **2022 Average Energy Usage** | **22,123 BTU/Gal** | **1,714 BTU/Gal** |

In addition to projecting the average energy usage of a dry mill ethanol plant in 2022 we have also projected the energy usage of a "best case scenario" plant. This plant was defined as a plant that used the combination of all the technologies considered that resulted in the lowest overall energy usage, as well as all the energy efficiency improvements discussed above. The technologies used by the best case scenario plant were CHP, dry fractionation, membrane separation, and raw starch hydrolysis. Corn oil extraction was not considered as plants would have either corn oil extraction or dry fractionation but not both, and dry fractionation resulted in greater energy savings. Best case scenario energy usage numbers were calculated for both natural gas and coal/biomass fired plants producing both dry and wet DGS. The results are shown below.

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[QQ] An Excel spreadsheet has been added to the docket showing the energy impact calculations of the technology improvements (EPA-HQ-OAR-2005-0161-2729).

**Table 1.5-16**
**2022 Best Case Natural Gas Dry Mill Plant Energy Usage**

| | 2022 Best Case Scenario (Dry DGS) | |
|---|---|---|
| | Thermal | Electrical |
| 2022 Base Plant | 28,660 BTU/Gal | 2,251 BTU/Gal |
| 2022 Best Case Scenario | 16,568 BTU/Gal | 1,682 BTU/Gal |
| | 2022 Best Case Scenario (Wet DGS) | |
| 2022 Base Plant | 17,081 BTU/Gal | 2,251 BTU/Gal |
| 2022 Best Case Scenario | 9,932 BTU/Gal | 1,682 BTU/Gal |

### 1.5.1.4 Projected Grandfathered Corn Ethanol Volume

As explained in the Section II.B.3 of the preamble, renewable fuel produced from new facilities which commenced construction after December 19, 2007 must achieve at least a 20% reduction in lifecycle greenhouse gas emissions compared to baseline lifecycle greenhouse gas emissions in order to generate RINs under the proposed RFS2 program.[RR] However, facilities that commenced construction on or before December 19, 2007 are exempt or “grandfathered” from the 20% GHG reduction requirement. In addition, facilities that commenced construction in 2008 or 2009 are grandfathered if they burn natural gas, biomass, or any combination thereof.

The volume of ethanol that is grandfathered under today’s RFS2 rule will be determined based on information received during the expanded registration process (refer to Section II.C of the preamble). However, as part of this final rulemaking, we analyzed the volume of corn ethanol that could potentially be grandfathered based on our knowledge of the industry.

To do so, we started with our assessment of corn ethanol plants that were operational, idled or under construction at the time of our November 2009 assessment. As shown in Table 1.5-7, excluding the planned facilities, this amounts to about 14.8 billion gallons of ethanol production capacity. Provided all the plants meet the definition of “commence construction” under §80.1403, the potentially grandfathered volume of ethanol falls just shy of meeting the 15 billion gallon conventional biofuel standard. However, actual baseline volumes established during registration could easily exceed 15 billion gallons. Furthermore, by allowing a 5% tolerance on the baseline volume to account for minor changes during ongoing maintenance of the facilities under §80.1403(a)(1), these plants could readily exceed 15 billion gallons of production.

Further examination suggests that all of today’s corn ethanol plants will likely be grandfathered under the RFS2 program because they are either fired with natural gas, biomass or a combination thereof and commenced construction by December 31, 2009 or they burn coal but commenced construction on or before December 19, 2007. A summary of grandfathering assessment logic we applied is found in Figure 1.5-5. The 20 coal-fired plants we considered in greater detail are presented in Table 1.5-17.

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[RR] In accordance with Section 211(o)(2)(A)(i) of the Clean Air Act as amended by EISA.

**Figure 1.5-5.**
**Potential Grandfathered Volume of Corn Ethanol Under RFS2**

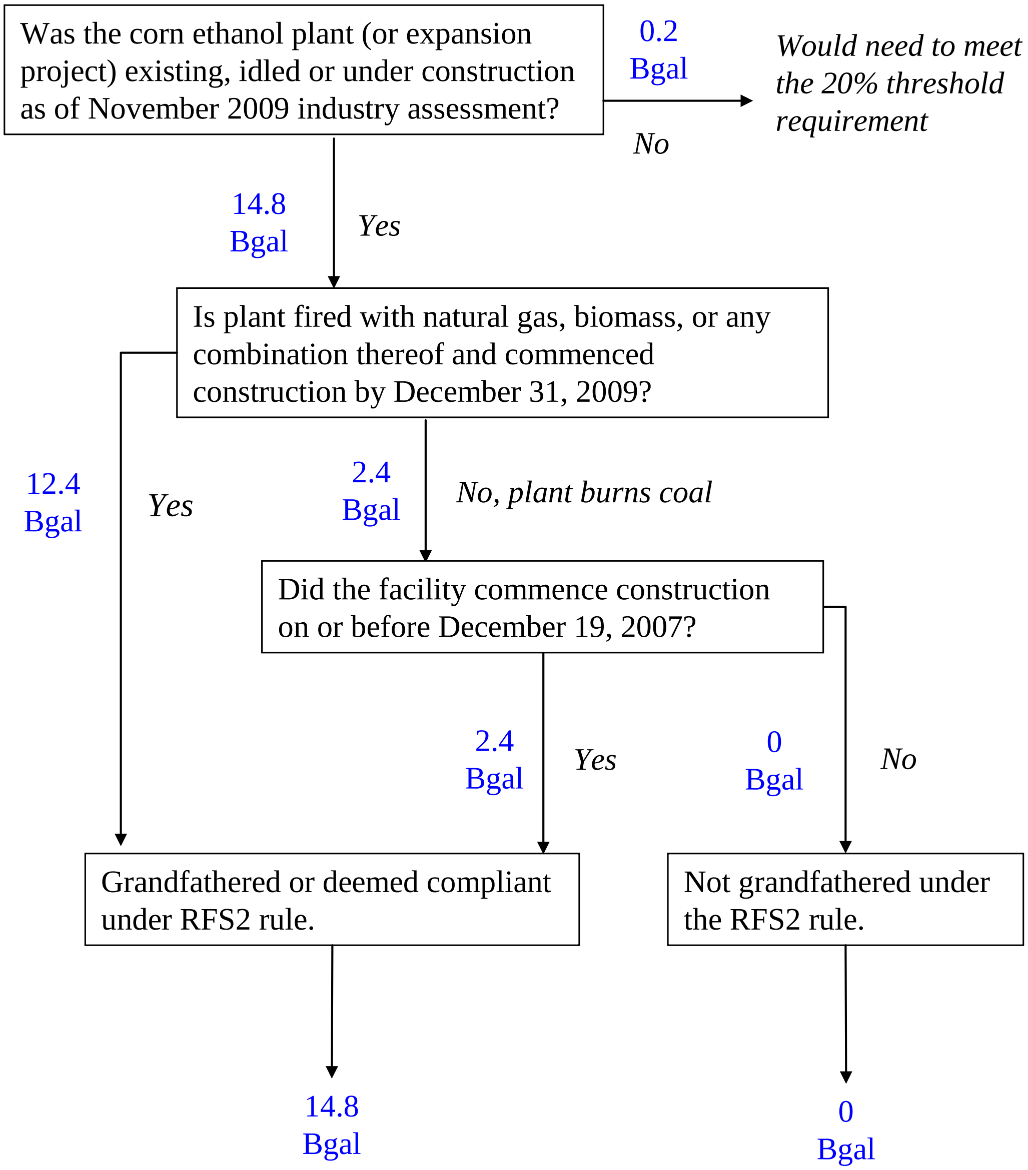


**Table 1.5-17.**
**Coal-Fired Corn Ethanol Plants**

| Plant/Company | Location | Capacity MGY | On-Line Date |
|---|---|---|---|
| Ag Processing Inc. | Hastings, NE | 52 | 1992 |
| Archer Daniels Midland (ADM)[a] | Cedar Rapids, IA | 250 | 1981 |
| **Archer Daniels Midland (ADM)[a]** | **Cedar Rapids, IA** | **275** | **Aug-10** |
| Archer Daniels Midland (ADM)[a] | Clinton, IA | 190 | 1981 |
| **Archer Daniels Midland (ADM)[a]** | **Columbus, NE** | **275** | **Aug-10** |
| Archer Daniels Midland (ADM)[a] | Columbus, NE | 95 | 1994 |
| Archer Daniels Midland (ADM)[a] | Decatur, IL | 290 | 1976 |
| Archer Daniels Midland (ADM) | Marshall, MN | 40 | 1988 |
| Archer Daniels Midland (ADM) | Peoria, IL | 210 | 1980 |
| Archer Daniels Midland (ADM) | Walhalla, ND | 25 | 1990 |
| Aventine Renewable Energy[b] | Pekin, IL | 100 | 1981 |
| Cargill[c] | Eddyville, IA | 35 | 1992 |
| Chief Ethanol Fuels Inc. | Hastings, NE | 62 | 1985 |
| Corn LP[d] | Goldfield, IA | 50 | Dec-05 |
| Grain Processing Corp | Muscatine, IA | 20 | May-00 |
| Heron Lake BioEnergy, LLC | Heron Lake, MN | 50 | Oct-07 |
| Lincolnway Energy LLC | Nevada, IA | 50 | May-06 |
| Red Trail Energy, LLC | Richardton, ND | 50 | Jan-07 |
| **Riverland Biofuels[e]** | **Canton, IL** | **38** | **Oct-08** |
| **Southwest Iowa Renewable Energy** | **Council Bluffs, IA** | **110** | **Feb-09** |
| Tate & Lyle | Loudon, TN | 126 | 1982 |
| | **Total Coal-Fired Capacity** | **2,393** | |

[a] Permitted to burn biomass, tires, petroleum coke, and wood waste in addition to coal .
[b] Recently filed for bankruptcy protection.
[c] Burns a combination of natural gas and coal.
[d] Burns a combination of coal and biomass.
[e] Formerly Central Illinois Energy.

As shown above, most of the coal-fired ethanol plants were built well before 2007 and thus should have little problem qualifying as grandfathered under the RFS2 rule. There are essentially four plants that could potentially pose a challenge with respect to the construction cutoff date set by EISA. These facilities, bolded in Table 1.5-17 above, include two dry-mill ADM plant expansion projects currently underway in Cedar Rapids, IA and Columbus, NE as well as Riverland Biofuels in Canton, IL, and Southwest Iowa Renewable Energy in Council Bluffs, IA. However, research and communications with these companies suggest that these plants commenced construction on or before December 19, 2007 and thus should be grandfathered and exempt from the 20% threshold requirement under RFS2.[262]

### 1.5.2 Imported Ethanol

In order to assess the potential for U.S. imported ethanol, we examined the chief countries that are currently producing or consuming relatively large volumes of ethanol. In particular, we chose to focus on Brazil, the European Union (EU), Japan, India, and China to determine whether each country will likely be an importer or exporter of ethanol in the future. The following sections first describe the ethanol demands of each of these countries due to enacted or proposed mandates and goals as well as their ability to supply those demands with domestically produced ethanol. With the exception of Brazil, we show that the majority of countries analyzed could likely be importers of ethanol in the future and therefore could compete with the U.S. for supplies of ethanol. We conclude our analysis by examining the most likely pathways for imported ethanol to the U.S., namely through the Caribbean Basin Initiative (CBI) and directly from Brazil.

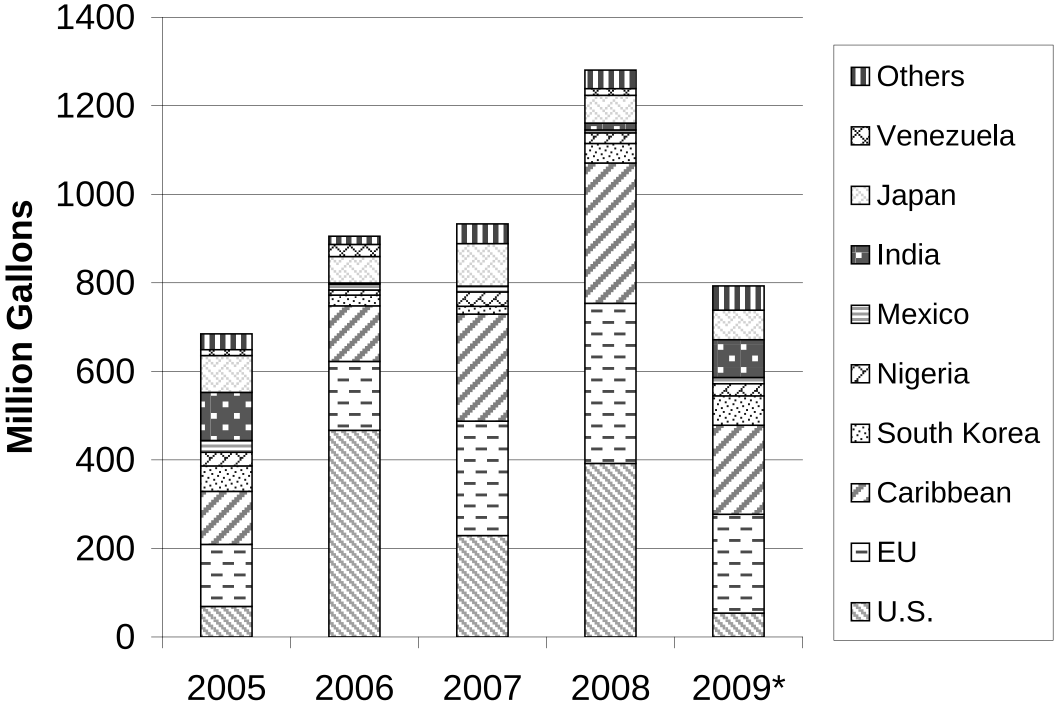
#### 1.5.2.1 Historic/Current Imports and Exports

*Brazil*

Much of the potential of imported ethanol will depend on the ability for Brazil to supply ethanol to the United States and other countries. This is because Brazil has been a top producer and is the top exporter of ethanol in the world. In fact, many countries are interested in Brazilian produced sugarcane ethanol because it is currently the least costly method for producing ethanol.

Brazil has been steadily increasing its exports of ethanol, with total exports escalating from under 700 million gallons in 2005 to over 1200 million gallons in 2008. As seen in Figure 1.5-6, Brazil exports ethanol to many different countries around the globe. Prior to 2006, the majority of Brazilian ethanol exports flowed to the EU and Caribbean due to favorable economics. In 2006, the majority of Brazilian ethanol exports (52%) went to the U.S as a result of the withdrawal of MTBE from the U.S. gasoline fuel pool and high oil prices. The EU, Caribbean, and U.S. have continued to be major importers of Brazilian ethanol in recent years.

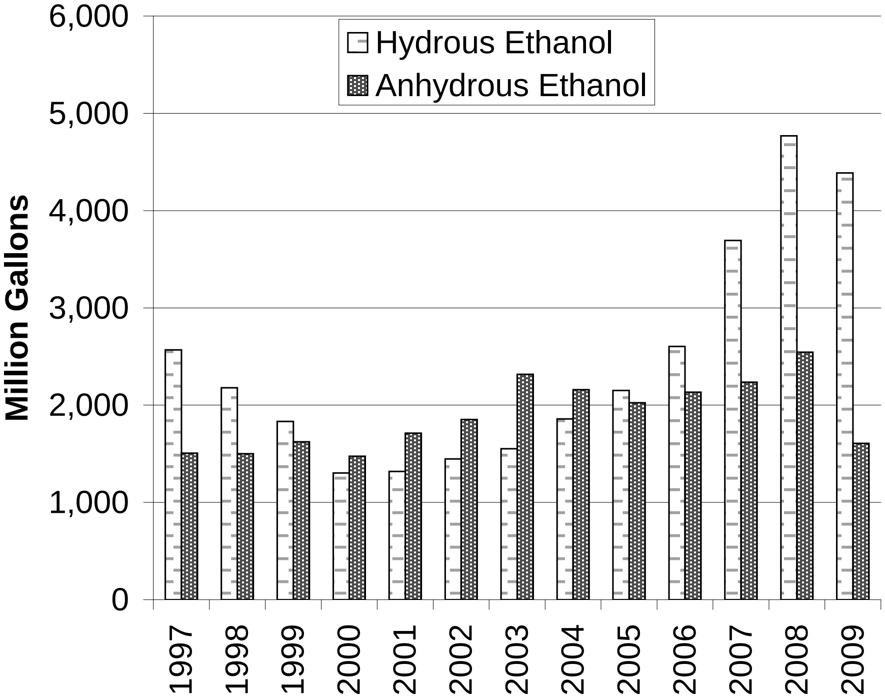
**Figure 1.5-6. Brazil Ethanol Exports (Includes all types of ethanol).**[263,264,265]



*January 2009-October 2009

Brazil currently produces both hydrous and anhydrous ethanol. Hydrous ethanol contains 96% ethanol and 4% water by volume, whereas anhydrous ethanol is made up of 99.5% ethanol and 0.5% water.[266] While hydrous ethanol is used in Brazil directly in Otto-cycle motors (as 100% ethanol by volume), anhydrous ethanol is mixed with gasoline at 20-25% by volume. Production of anhydrous ethanol to be mixed with gasoline has fallen since the 2005/2006 harvest, on account of the smaller share of cars running exclusively on gasoline. This was especially due to the success of flex vehicles with Brazilian customers.[267] In fact, sales of flex-fuel vehicles (FFVs) in Brazil, those that can use any mixture of gasoline and ethanol from 0 to 100%, have grown dramatically, with domestic FFV sales representing 85% of vehicles sold between January 2009 and October 2009.[268] Hydrous ethanol accounted for 65% of ethanol produced in Brazil in 2008, and 73% of ethanol produced as of December 1, 2009. Figure 1.5-7 shows the historical production of hydrous and anhydrous ethanol in Brazil.

**Figure 1.5-7.**
**Historical Ethanol Production of Hydrous and Anhydrous Ethanol in Brazil.[269]**

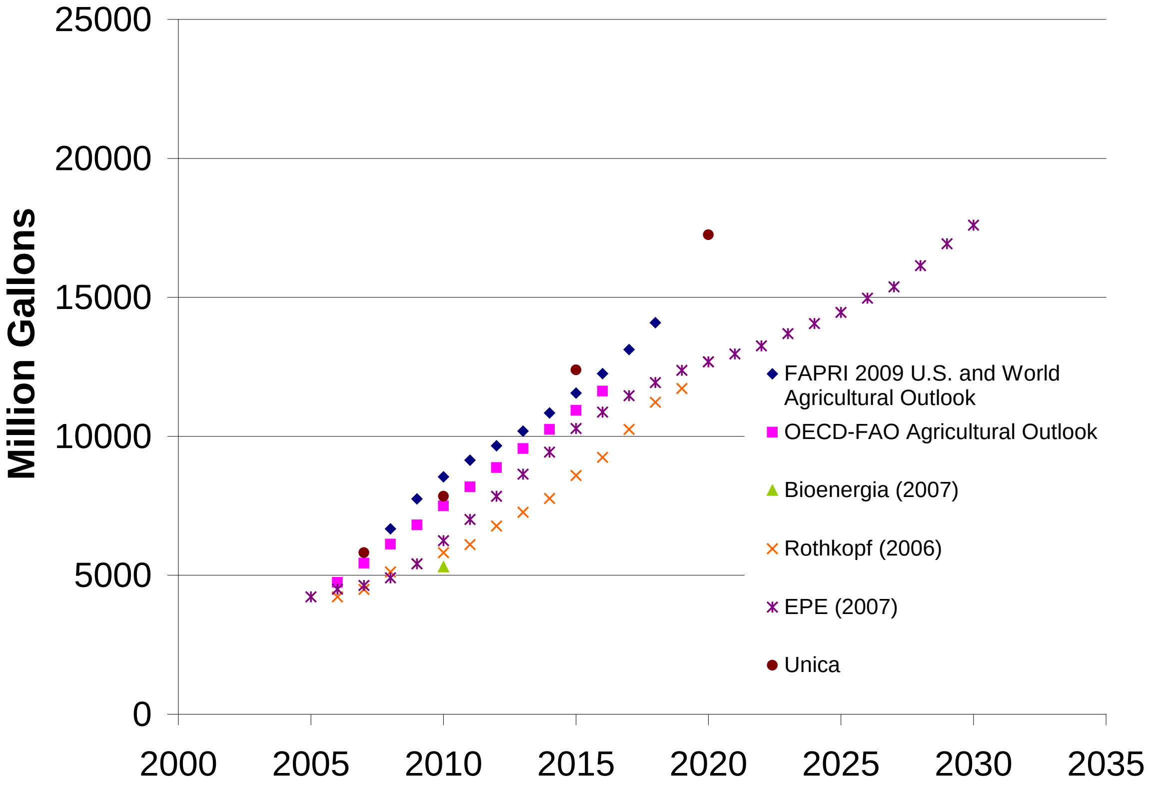


*2009 data is up to date as of 12/01/2009

In contrast to Brazil, ethanol consumed in the U.S. must first be converted to anhydrous ethanol before it can be used in conventional or FFV vehicles. This differs from Brazil because Brazilian FFVs have been designed to use hydrous ethanol, or E100 (100% ethanol by volume) for the conditions in Brazil, whereas U.S. FFVs can only use up to E85 (85% ethanol and 15% gasoline by volume). As a result, if hydrous ethanol is exported from Brazil, it must be dehydrated somewhere else before it can be used in the U.S. This is the case for the majority of ethanol exported from Brazil to the Caribbean, where it is dehydrated and often re-exported to the U.S. for consumption.

In terms of future ethanol production, however, there has been much speculation about Brazil's ability to increase production. Sugarcane analyst Datagro recently stated that Brazil's ethanol fuel production would have to grow by approximately 800 million gallons a year through 2025 to keep up with demand at home and abroad.[270] Estimates of future ethanol production in Brazil vary greatly, see Figure 1.5-8. Brazil's government has adopted plans to meet global demand by tripling production by 2020.[271] This would mean a total capacity of approximately 12.7 billion gallons, to be achieved through a combination of efficiency gains, greenfield projects, and infrastructure expansions. Estimates for the required investment tend to range from $2 billion to $4 billion a year. Other estimates indicate that, based on current projects, the required investment in capacity expansion is $3-4 billion annually.[272] If global demand were to increase much more than Brazil is planning, then capacity would need to expand even further and greater investment would be required.

Figure 1.5-8. Estimated Brazilian Ethanol Production Volumes[273]



To meet the growing demand, the Brazilian sugar and ethanol industry is already rapidly expanding and numerous mills have been planned. Brazil currently has nearly 400 sugar and ethanol mills, with more anticipated over next few years.[274,275,276] Brazil's state-owned development bank BNDES said the country is set to invest $13.1 billion between 2007 and 2011 in 89 new sugar and ethanol mills.[277] Some estimate even more, where investments in sugarcane processing factories are expected to top $23 billion over the next four years.[278] Investments include a project by Odebrecht, a Brazilian engineering company that will invest $2.6 billion dollars over the next decade to build 12-15 plants with a combined capacity to produce ~ 400 million gallons per year of ethanol.[279] Even U.S. ethanol producer ADM is preparing to enter the sugarcane business in Brazil. A recent quote by ADM's senior vice president of strategy, Steve Mills, said that sugarcane ethanol is now "a key component" of ADM's short-term strategy and, "We're devoting a lot of time and energy to this area. We're not talking about something 10 years down the road. It's on the front burner."[280]

In addition to expanding sugarcane production and ethanol plant capacity, Brazil will need to improve its current ethanol distribution infrastructure. Brazil's transport system is predominantly road-based.[281] Railroad infrastructure and use of a waterway system is lacking, as well as very low availability of multi-mode terminals. Logistics represent approximately 22% of the export expenses and is one of the areas where costs need to be reduced in order for Brazilian ethanol to become more competitive abroad.[282]

One way to deal with the lack of infrastructure is to expand the pipeline network. Petrobras, Brazil's largest petroleum refiner is planning to build a pipeline to transport ethanol destined for export from the states of Sao Paulo, Minas Gerais, Mato Grosso, Mato Grosso do Sul, Goias, and Parana. The pipeline is anticipated to go online in October 2010, with $232 million invested in the project. By 2012, Petrobras will spend more than $1.6 billion to improve logistics infrastructure to transport Brazilian ethanol. By 2011, Petrobras has the goal of exporting 920 million gallons per year.[283] One of the pipelines will run from Goias state in Brazil's center-west to Petrobras's Paulinia refinery in Sao Paulo State. The project is called PMCC Projetos de Transporte de Alcool. The line is expected to have the capacity to ship 3.2 million gallons of ethanol annually.[284]

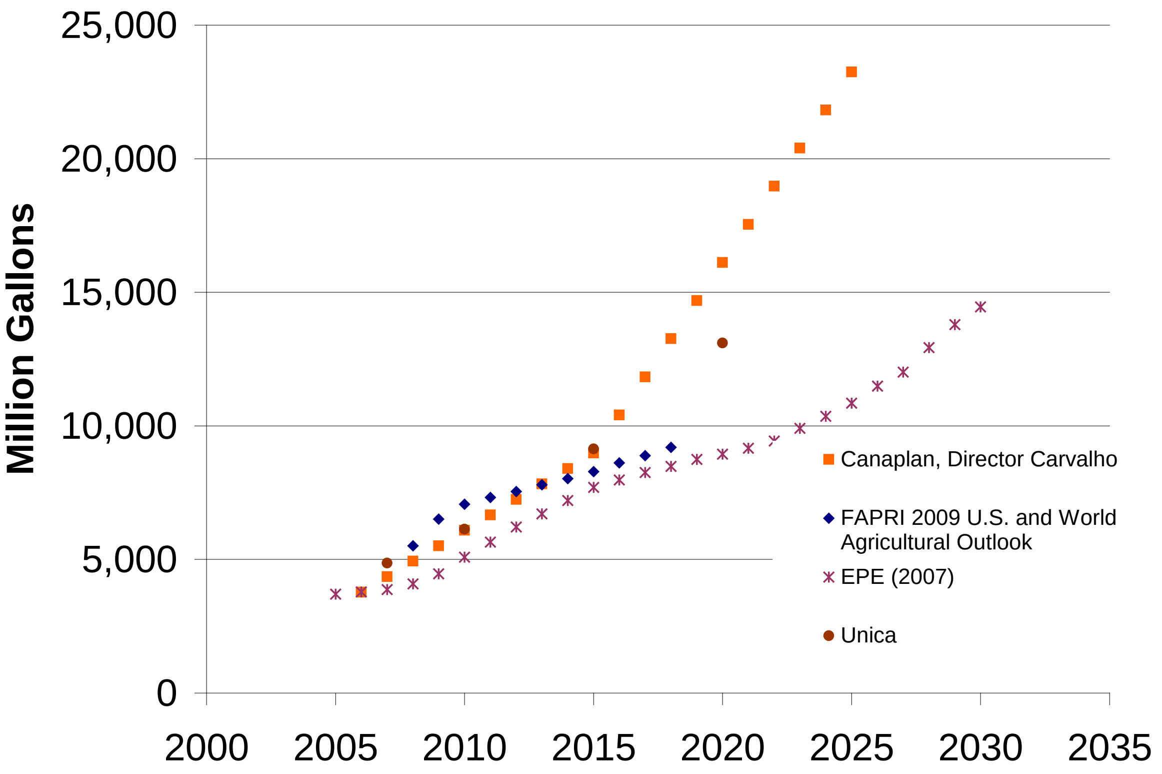
Other competitors include the joint venture from Cosan, Copersucar, and Crystalsev which will make initial investments of $11.5 million apiece to install an ethanol-only pipeline between the oil refinery in Paulinia, to an ethanol offloading terminal on the state's coast. In addition, at least three major private equity groups (Infinity, Clean Energy Brazil, and Brenco) plan to invest $1 billion in a 683-mile pipeline expected to be completed by 2011 with a capacity to deliver 1.1 million gallons of ethanol a year. In total, it is estimated that Brazil will need to invest $1 billion each year for the next 15 years in infrastructure to keep pace with capacity expansion and export demand.[285]

Another area that requires investment is in R&D and education. Currently, Brazil produces only 0.08 engineers for every 1000 people, compared to 0.2 in the U.S., 0.33 in the EU, and 0.8 in Korea.[286] Since certain types of education require a long lead time (e.g., scientific training) Brazil will need to continue to invest in training and professional development for the sector's labor pool to meet the growing demand in the biofuels industry.

Before ethanol can be exported to other countries, Brazil's own domestic fuel consumption must be met. Brazil currently has an ethanol mandate of 25%.[287] The ethanol to gasoline mix is set by the Brazilian government, which has the flexibility to adjust the ethanol mandate from 20-25% by volume.

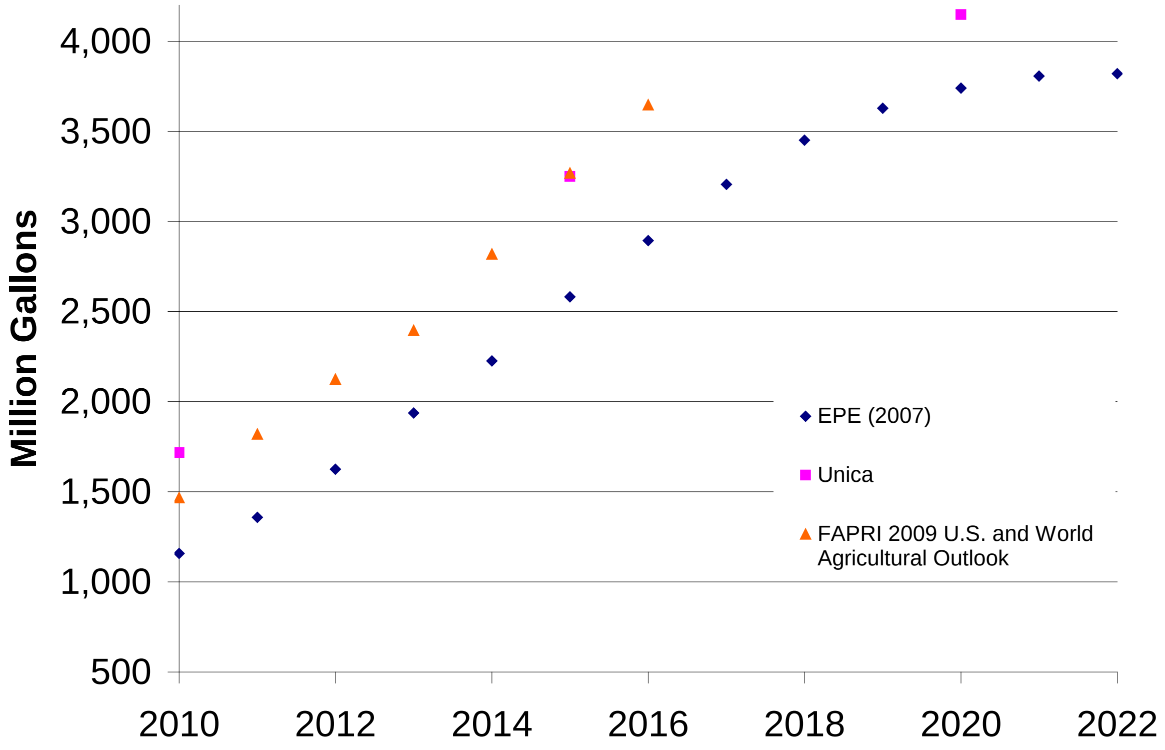
At some point in the future, Brazil's light vehicle fleet may become saturated with FFVs in preference to mainly gasoline fueled vehicles. As such, the rate in domestic demand for ethanol is expected to begin to slow.[288] Thus, as domestic demand begins to level off, some experts believe that there is a significant possibility that exports will become more relevant in market share terms. Figure 1.5-9 shows various estimates for future Brazilian ethanol domestic consumption.

**Figure 1.5-9. Estimated Brazilian Ethanol Consumption Volumes** [289]



After domestic consumption is met, the rest of the ethanol can be available for exports to other countries. Potential worldwide exports basically equal the total production minus the total consumption. Given the available data, only three sources estimated both production and consumption for some of the years during 2010-2022. As such, these values were used to compute reasonable export volumes from Brazil as seen in Figure 1.5-10. Estimates from EPE and Unica indicate that as much as 3.8-4.2 billion gallons could be exported by Brazil in the 2020/2022 timeframe. Longer timeframe estimates from sugarcane analyst Datagro project international ethanol sales to grow to 6.6 billion gallons by 2025.[290]

**Figure 1.5-10. Estimated Brazilian Export Volumes**



*The European Union (EU)*

Although the EU market has largely focused on biodiesel, ethanol has become increasingly important. Fuel ethanol production in the EU has grown from 140 million gallons in 2004 to 754 million gallons in 2008.[291] Germany, Spain, France, Poland, and Hungary represent almost 80% of the production in 2008. Historically, however, ethanol production volumes have been lower than mandatory blending targets.

The EU has set several targets for biofuel consumption over the past few years. In 2001, an EU Directive established that by 2005 biofuels should cover 2% of the total fuel consumption (energy basis), while the target for 2010 was set at 5.75%. However, in recent years the average biofuel contribution has been much less (0.5%, 0.6% and 1% in 2003, 2004, and 2005, respectively).[292] It is also not expected that the EU will achieve its target of 5.75% of road transport by 2010.[293]

In April 2009, the EU Energy and Climate Change Package (CCP) was adopted. This package includes a minimum target requiring 10% renewable energy use in transport by 2020. Most, if not all of this 10% is expected to come from increased biofuel use.[294] The biofuels used must meet certain criteria to be taken into account for the 10% goal, e.g., meet GHG emissions reduction thresholds. The International Energy Outlook (IEO) 2009 forecasts OECD European countries will consume 16.5 quadrillion Btu of transport fuel in 2010, growing to 17.6 quadrillion Btu by 2030.[295] Assuming a split of nearly 70% fuel volume consumed as diesel and

30% consumed as gasoline (current use), a 10% by energy requirement would require roughly 6.8 billion gallons of ethanol in 2022.[SS,296] However, this may be a slight overestimate of gasoline use since the overall gasoline consumption in the EU is declining as a result of the increasing popularity of more economic diesel-powered cars. Other sources indicate smaller gasoline consumption volumes are possible by the 2020/2022 timeframe which when translated equals 5.2-5.4 billion gallons of ethanol assuming a 10% energy requirement.[297,298] According to the "FAPRI 2009 U.S. and World Agricultural Outlook", ethanol production in the EU is expected to grow to 1.6 billion gallons by 2018. Taking this into account, the EU would need to import approximately 4-5 billion gallons of ethanol in order to meet the 10% volume requirement if only traditional crops are used.

As of September 2009, the installed capacity of the EU ethanol industry is 1.7 billion gallons, while 0.6 billion gallons are under construction and another 3 billion gallons has been announced.[299,300] Totaling these capacity estimates, the EU would have 5.3 billion gallons ethanol capacity. In the EU, these facilities mainly process wheat, corn and sugar beet derivatives, with a limited amount produced from barley, rye and the surplus of wine alcohol. While not all the announced projects in the EU will be completed, this gives an estimate of how fast and large ethanol production in the EU could grow. If we assumed that the EU could produce this volume by 2022, as little as 1.5 billion gallons would need to be imported from other countries assuming a 6.8 billion gallon demand due to the 10% mandate. Thus, it appears likely from the above analysis that the EU will continue to be a net importer of biofuels under most future scenarios.

*Japan*

Historically, Japan has not produced much ethanol (24,000 gallons in 2008) and has imported the majority of its consumption.[301,302] Now the government is showing signs of encouraging biofuels production by promoting (not mandating) a 3% blend of ethanol in gasoline. At the very least, a non-mandatory 3% blend will create a demand of 106-132 million gallons of ethanol.[303] This is similar to Japan's Agency for Natural Resources and Energy target to replace 132.1 million gallons of transportation fuel by 2010, using ethanol and biodiesel.[304]

With a 3% ethanol blend, ethanol trade may increase substantially with Japan (this may even reach over 1.5 billion gallons annually if a 10% ethanol blend is implemented nationwide in Japan, approximately 500 million gallons with 3% ethanol blends).[305] While the use of greater than 3% blends in Japan may be unlikely, the Japanese government has mandated that all gasoline powered vehicles are able to run on 10% blends by 2030 and may also enact legislation to require all new vehicles to be E10 compatible by 2012.[306,307]

One challenge with the use of ethanol in Japan is its distribution. As E5 and higher ethanol blends have been shown to be corrosive to aluminum and rubber car parts, Japan is looking into using ETBE blends of 7% and even 20-25% instead of ethanol.[308] The Petroleum Association of Japan has announced that gasoline containing ETBE blends of 7% will be available for general public consumption by 2010. As ETBE is produced using ethanol as a

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[SS] Assuming energy contents 115,000 Btu/gal for gasoline and 77,012 Btu/gal for denatured ethanol and 17.5 quadrillion Btu in 2022 feedstock, this could create a domestic ethanol demand of 90-100 million gallons.[309] Imports of ETBE were roughly 1.7 million gallons in 2008.[310]

Table 1.5-18 details select ethanol model plants and facilities in Japan. In total, there are close to a dozen ethanol facilities nationwide, however, details on each facility were not fully available and most are considered small-scale.

**Table 1.5-18. Select Ethanol Model Plants and Facilities in Japan[311]**

| Plant | Capacity | Feedstock |
|---|---|---|
| Nippon Steel Plant | 38,000 gallons/year | Food waste from: supermarkets, restaurants, schools, hospitals |
| Mitsui Engineering & Shipbuilding Co. | Not available | Agricultural wastes: felled oil palm trunks, empty fruit bunches, fibrous fruit wastes, kernel shells |
| Shimizucho, public-private partnership between Mitsubishi Corp. and Hokuren | 4 million gallons/year | Off-spec wheat and sugarbeets |
| Tomakomai | 4 million gallons/year | Rice |
| Obihiro City, Hokkaido run by Tokachi Foundation | Small volumes | Wheat |
| Niigata, joint operation with Zen-noh | Small volumes | Rice |

Historically, Japan has relied on nations such as Brazil to supply ethanol, although it is almost all for industrial use. Imports of ethanol for transportation use are currently negligible; however, future imports may be possible from Brazil given the joint ventures established between Japanese and Brazilian firms. In early 2005, Japan and Brazil signed an agreement for a bilateral biofuels program to export Brazilian ethanol and biodiesel to Japan. Japan's investment will be used to install new ethanol facilities, increase acreage of sugarcane production, and modernize the infrastructure necessary for the transportation of ethanol.

One such partnership is between Brazilian oil company, Petrobras, and trading house Mitsui & Co., with financial support from Japan Bank for International Cooperation. The companies are in the process of analyzing 40 projects evaluated at $8 billion which produce alcohol and sugar from sugarcane. According to Paulo Roberto Costa, head of Petrobras' supply division, "Our target is to produce ethanol to be exported *only* to Japan." Petrobras plans to produce a total of 1 billion liters (264 million gallons) of alcohol annually at five processing plants in the states of Mato Grosso, Goias, and Minas Gerais. Each of the five processing plants will produce approximately 50 million gallons per year within the next 2 ½ years, and the whole production will be exported to Japan. In order to convince Japan that Petrobras has adequate ethanol supplies it was noted that their processing facilities will not be able to produce sugar, only alcohol.[312] With this amount (264 million gallons) slated for Japan only, other countries may have to either develop their own contracts with Brazil to ensure a stable supply.

Petrobras also recently bought a 90 percent stake in Exxon Mobil's Okinawa oil refinery that may serve as a staging point for Brazilian ethanol exports to Japan and the rest of Asia. This may help mitigate one of the main problems for Petrobras and other major exporters, a lack of offloading infrastructure.[313]

The prospect for large domestic production of ethanol in Japan appears to be small due to limitations on feedstock. In fact, Japan's first biomass plan, "Biomass Nippon Strategy" unveiled in December 2002 and updated in 2008 reveals that the Government of Japan's (GOJ's) current thinking, given limited agricultural resources, is to focus on cellulosic biofuel as the future for Japan's biofuel production.[314] The Agriculture Ministry states that Japan has enough feedstock to produce 26.4 million gallons per year, however, the Ministry of Environment (MOE) expects Japan to meet only 10% of the 132.1 million gallon target (or 13.2 million gallons) with domestic ethanol production.[315] The Ministry of Agriculture and Fisheries (MAFF), on the other hand, predicts that Japan could reasonably expect to supply approximately 95 million gallons. Even with these higher domestic production estimates, Japan would still be a net importer of fuel ethanol if the biofuels target is met. Thus, the potential estimated demand for imported ethanol ranges from 11 million gallons to 1572 million gallons depending on the type of mandate assumed and the differences in the estimates of domestic ethanol production.

### *India*

India has continued to focus on the use of non-food sources (e.g., sugar molasses) for the production of ethanol for blending with gasoline. The amount of ethanol blended into gasoline in India has fluctuated in the past few years. The government's current target of 5% blending of ethanol with gasoline has been partially successful in years of surplus sugar production, but falters when sugar production declines.[316] Commercial production and marketing of ethanol-blended gasoline started in January 2003 when the Ministry of Petroleum and Natural Gas launched the first phase of the ethanol blended petrol (EBP) program that mandated blending of 5% ethanol in gasoline in 9 states (out of a total of 28) and 4 union territories (UT) (out of a total of 7). In 2004, ethanol blending in gasoline had to be halted because of a lower sugar output due to a drought, which increased prices. However, production started back up in late 2005 when a fuller sugarcane molasses crop became available. Then in September 2006 the government announced the second phase of the EBP that mandates 5% blending ethanol with gasoline in 20 states and 8 union territories.[TT] The mandate was effective starting in November 2006 and would have required about 159 million gallons to be used. However, the program only started with 10 states and was not implemented in other states due to high state taxes, excise duties and levies.

Industry sources report that ethanol supplies for the EBP program have come to a virtual halt in most states since October 2008.[317] In fact, industry sources estimate that only 143 million gallons of ethanol have been supplied to the EBP program by the end of April 2009 during the

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[TT] The number of union territories appears to have changed since 2006.

past two and a half years. The government has had plans to extend the ethanol blend ratio to 10% in a third stage once the program is extended to all target states. The original plan was a minimum 10% ethanol blend by October 2008; however, this was put on hold because of the sharp fall in crude oil prices and because of technical concerns raised by the Society of Indian Automobile Manufacturers (SIAM). The main concern is that vehicles with older engines may not be able to use 10% blends without engine modifications (e.g., two-wheelers). In December 2009, India's government has indicated the urgency to kickstart the 5% blending program because the requirement of ethanol has increased to 225 million gallons in the course of the delay in implementation (since 2006).[318] Regardless, the government announced a draft National Biofuel Policy in September 2008 to raise the blending level to 20% of total fuel usage by 2017 (includes biodiesel).[319] Industry sources expect the National Biofuel Policy may be reviewed again soon, however, approval by the Parliament may take some time.

India has about 320 distillers with a production capacity of about 925 million gallons. Due to the government's ethanol policy, over 115 distilleries have modified their plants to include an ethanol production line, with a total production capacity of 396 million gallons per year, enough to meet the estimated demand for E5. Under an E10 mandate, however, the current ethanol production capacity would need to be enhanced.

Some oil companies are instead pushing for imports of ethanol. However, there is an import duty of 28.64% on the cif value for denatured ethanol. The c.i.f. (cost, insurance, and freight) value represents the landed value of the merchandise at the first port of arrival in a given country. In comparison to the U.S. which has a tariff of 54 cents per gallon (with 45 cents per gallon offset by the ethanol blending subsidy) and a smaller ad valorem tax of 2.5% for denatured ethanol, import duties in India are much higher.

The analysis of India's biofuels developments appears to indicate that it will be self-sustaining if E5 is mandated (as noted by the sugar industry). However, as India strives to meet its E10 goal, it may need to rely on imports from other countries. India's own domestic production may grow from its current estimated production of 26 million gallons of ethanol (marketing year 2008/09), with production capacity expanding to 396 million gallons per year. To meet current E5 and E10 mandates, approximately 225 million gallons to 450 million gallons per year of ethanol, respectively, is required (note that this will continue to increase as fuel demands increase). Therefore, depending on the amount of ethanol that India chooses to mandate, India could either be an importer of ethanol or be able to meet its goals with domestically produced ethanol.

### *China*

In 2008, China was the world's fourth largest fuel ethanol producer, producing around 500 million gallons.[320] The majority of fuel ethanol in China is made from corn.[321,322] However, concerns in China about the security of their food supply and the inflationary impact of biofuels which use grains as feedstock have influenced the feedstocks to be used in the future. With a population of 1.3 billion people, corn growers have to meet the demand for food while also providing feedstock for fuel. In addition, they supply livestock feed for which demand is estimated to rise.[323]

In response to these food and feed demands for corn, according to the National Development and Reform Commission (NDRC), China stopped approvals for industrial corn processing for three years and suspended approved projects which had not yet started construction.[324] Since 2007, corn consumption by the deep-processing sector (i.e., transformation of corn into industrial products like ethanol) will be restricted to about 26 percent of China's total corn consumption.

The National Development and Reform Commission (NDRC) stated in their 11th Five Year Plan (2006-2010) that the production of approximately 2 billion gallons of grain-based ethanol will not threaten the country's grain security. In 2005, there were four fuel ethanol plants operating in the country with a production capacity of approximately 300 million gallons: Jilin Fuel Ethanol Co., Anhui BBCA Biochemical Co., Henan Tian Guan Fuel Ethanol Co., and the China Resources Alcohol Co.[325,326] These plants were established after 2000 to address a surplus of grains in China at the time. Since then, total production in 2008 has increased to an estimated 521 million gallons, see Table 1.5-19.[327]

**Table 1.5-19. Fuel Ethanol Production in China**

| Location (Province, City) | Company Name | Principal Feedstock | Estimated 2008 Production (Mgal) | Estimated 2009 Production Capacity (Mgal) |
|---|---|---|---|---|
| Heilongjiang, Zhaodong | China Resources Alcohol Co. | Corn/Rice | 59 | 59 |
| Jilin, Jilin | Jilin Fuel Ethanol Co. | Corn | 155 | 165 |
| Henan, Nanyang | Henan Tian Guan Fuel-Ethanol Co. | Wheat | 135 | 149 |
| Anhul, Bengbu | Anhui BBCA Biochemical Co. | Corn | 132 | 145 |
| Guangxi | Guangxi COFCO Bio-Energy Co. | Cassava | 40 | 66 |
| Total | | | 521 | 584 |

As seen in the above table, several distilleries have been looking into alternative feedstocks.[328] Examples of alternative feedstocks include sorghum, wheat, cassava, and sweet potato. These crops, however, are grown in much smaller quantities than corn. As such, if China ethanol production expands, China may have to rely on imported feedstocks.[329]

China began mandating fuel ethanol blending in gasoline in June 2002.[330] In 2004, the Chinese government introduced an ethanol mandate of 10% (E10) in several provinces-Helongjiang, Jilin, Liaoning, Henan, and Anhui. This mandate was further expanded to 27 cities in the provinces of Shandong, Jiangsu, Hebei, and Hubei in 2006. To keep up with fuel demand, a National Plan calls for fuel ethanol production to rise from approximately 330 million gallons of ethanol per year to 660 million gallons by 2010 and 3.3 billion gallons by 2020.[UU,331]

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[UU] Assuming a conversion of 1 million tonnes of ethanol equals 330 million gallons.

China may soon become a major importer of ethanol, especially if the E10 blend is extended across the country. With a nationwide E10 blend in 2020, biofuels demand would be approximately 7.6 billion gallons of ethanol.[332] Even if the National Plan which calls for China's domestic fuel ethanol production to reach 3.3 billion gallons by 2020 is met, a nationwide E10 blend would result in a supply shortfall of about 4.3 billion gallons of ethanol.[333] Another study, the "FAPRI 2009 U.S. and World Agricultural Outlook" also indicates that China would be a net importer of ethanol in the future (out to 2018), where domestic production only reaches approximately 600 million gallons. Assuming a possible E10 mandate nationwide and the projections for domestically produced ethanol, China would need to import approximately 4.3-7.0 billion gallons of ethanol per year.

### *Other Countries*

Although Brazil is the largest exporter of ethanol, there may still be other countries that could provide additional ethanol to the U.S. In fact, trace amounts of ethanol entered the U.S. market from Argentina, Canada, Netherlands, and Pakistan in the past.[334] The North American Free Trade Agreement (NAFTA) is similar to the Caribbean Basin Initiative (CBI) in that it welcomes tariff-free ethanol imports from Canada and Mexico.

In addition, there may also be other countries that are beginning biofuels programs and could demand smaller volumes of ethanol in the future. We provide a list of the potential mandates and goals for other countries below in Table 1.5-20. This list is not meant to be all-inclusive, but rather a look at biofuel initiatives in other countries.

**Table 1.5-20**
**Potential Mandates and Goals for Various Countries**[335,336,337,338,339,340,341,342]

| | |
|---|---|
| Argentina | Former Argentine President Nestor Kirchner signed a law in February 2007 implementing tax breaks and fuel-content mandates for biofuels. The Biofuels Act includes tax breaks for companies investing in the biofuels sector and mandates 5% ethanol in gasoline by 2010. Analysts estimate that the country will need 270 million liters per year of ethanol (71 million gallons per year) to satisfy the E5 requirements in 2010, which some believe will not be fully complied. In January 2008, Congress passed a law that promotes production of bioethanol from sugarcane, allowing sugar mills to participate under the biofuel promotional regime. |
| Australia | The Australian government has set a biofuels target of 93 Mgal by 2010 according to the 'Biofuels for Cleaner Transport' 2001 election policy. This target was never mandated in legislative form.<br>Queensland- In early August 2006 a mandate for a minimum of 5% ethanol from December 21, 2010.<br>New South Wales (NSW)- Beginning in September 2007, fuel supplied to wholesalers in New South Wales will be required to contain 2% ethanol. Proponents of ethanol in the region want to increase the mandate to 4% in 2009 and 10% in 2010.<br>Australian Capital Territory (ACT)- The ACT does not plan to mandate ethanol. Generally this territory follows the policies of NSW because most of their fuel supplies are sourced from NSW.<br>Victoria- Biofuels target of 5% of fuel market by 2010 (106 Mgal), this includes biodiesel.<br>South Australia- No plans to mandate of set a target for biofuels use.<br>Northern Territory- No plans to mandate or set a target for biofuels known.<br>Western Australia- Biofuels target of 5% of fuel market by 2010.<br>Tasmania- The alternative fuels policy is currently based on CNG use.<br>No plans to mandate or set a target for biofuels known. |
| Canada | On June 26, 2008, the Canadian Senate passed Bill C-33, which will require the use of 5% renewable content in gasoline by 2010. Canada's Government General Michaelle Jean signed the bill after it was passed in the senate, making it official.<br>Saskatchewan- Enacted in October 2006 a 7.5% ethanol mandate in gasoline (approximately 131 Mgal)<br>Ontario- Enacted in January 2007 a 5% ethanol mandate in gasoline, tentative increase to 10% by 2010<br>British Columbia- Bill C-16 to pass soon, 5% ethanol by 2010 to support federal plan<br>Alberta- Has not set its own standard as it prefers a national approach<br>Manitoba- Beginning April 1, 2008, 8.5% in gasoline (approximately 130 Mgal)<br>Quebec- 5% ethanol in gasoline by 2012, expects source to be met with cellulosic ethanol production<br>Nova Scotia- No goals for biofuels<br>New Brunswick- No goals for biofuels<br>Newfoundland Labrador,PIE- Interest on the East Coast, but nothing as of May 2008<br>North West Territories, Yukon, Nunavut- No goals for biofuels |
| Columbia | In September 2001, the Colombian Government issued Law 693, which made it mandatory to use 10% ethanol blends in gasoline in cities with populations larger than 500,000 inhabitants by the year 2008. The law went into effect in September 2005. Ethanol production, however, could not cover the entire country's demand, and thus the government established a phase-in period throughout the country for mandatory ethanol use. |
| Mexico | On February 1, 2008, the Mexican Government published the Biofuels Promotion and Development Law (LPDB) establising legal framework from which all biofuel public policies will develop. The law does not currently state specific mandates for biofuels. |

### *Summary of Potential Import/Export Demands*

For the main countries we have analyzed from above, there appears to be a large potential demand from the EU, Japan, India, and China for imported ethanol. See Table 1.5-21 for a summary of potential import demand by 2020/2022. Total import potential demand from all these countries could range from approximately 4.4-14.3 billion gallons. If these countries decide to meet their mandated ethanol blends or enact new mandates, this could greatly increase the amount that each country would demand from other countries. As discussed above, Brazil is only expected to export a total of 3.8-4.2 billion gallons by 2022. This is significantly below the volume we estimated that could be potentially demanded by other countries in the future. Therefore, it is likely that unless Brazil increases production much more than its government projects, the EU, Japan, India, and China will not be able to meet their stated goals. This also indicates that the U.S. will likely compete with other foreign countries for exports from Brazil. This analysis, however, only considers non-cellulosic biofuel potential. If cellulosic biofuel production develops in these countries, it is entirely possible that the biofuel demands could be lower due to greater supplies. We briefly discuss the potential for imported cellulosic feedstocks or biofuels in Section 1.1.2.6.

**Table 1.5-21. Potential Import Demand:**
**EU, Japan, India, and China by 2020/2022 (billion gallons).**[VV]

| Country | EU | Japan | India | China | Total |
|---|---|---|---|---|---|
| Potential Domestic Production | 1.6-5.3 | 0-0.1 | 0-0.4 | 0.6-3.3 | |
| Potential Consumption | | | | | |
| Petrobras Contract | n/a | 0.3 | n/a | n/a | |
| E3 | n/a | 0.5 | n/a | n/a | |
| E5 | n/a | n/a | 0.2 | n/a | |
| E10 (or 10% by energy for EU) | 5.2-6.8 | 1.6 | 0.5 | 7.6 | |
| 7% ETBE | n/a | 0.1 | n/a | n/a | |
| **Potential Import Demand** | **0-5.2** | **0.1-1.6** | **0-0.5** | **4.3-7.0** | **4.4-14.3** |

### 1.5.2.2 Projected Growth Under RFS2

As long as imported ethanol is cost-competitive with gasoline, there will continue be a demand for it. As our analysis from above shows, Brazil is the only country that will likely be able to provide a significant volume of ethanol to the U.S. Accordingly, Brazil will ship ethanol to the U.S. and other countries in the most cost-effective way.

The pathway Brazil chooses to ship ethanol will likely depend on the tariffs and taxes put in place by receiving nations. Specifically, the U.S. places a 54 cent tariff on all imported ethanol (as well as a 2.5 percent ad valorem tax for un-denatured ethanol and a 1.9 percent tax for denatured ethanol). A key reason for establishing a tariff was to offset a tax incentive for ethanol-blended gasoline, which is currently set at 45 cents per gallon of pure ethanol.[WW] This analysis assumes that both the tax subsidy and the tariff will continue in the future.

The tariff can be avoided by first shipping ethanol to countries under the Caribbean Basin Initiative (CBI) and then to the U.S. Historically, the majority of CBI ethanol to the U.S. comes from dehydrating ethanol from Brazil. Legislation and agreements since the 1980s have waived or significantly reduced the tariff on imports from Canada, Mexico, and those nations covered under the CBI. There are currently nineteen countries that can benefit from the CBI program. These countries are: Antigua and Barbuda, Aruba, Bahamas, Barbados, Belize, British Virgin

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[VV] Ranges are calculated assuming the potential values for production and consumption

[WW] Prior to the 2008 Farm Bill, the tax incentive was set at 54 cents per gallon

Islands, Costa Rica, Dominica, Grenada, Guyana, Haiti, Jamaica, Montserrat, Netherlands Antilles, Panama, St. Kitts and Nevis, St. Lucia, St. Vincent and the Grenadines, and Trinidad and Tobago.[343]

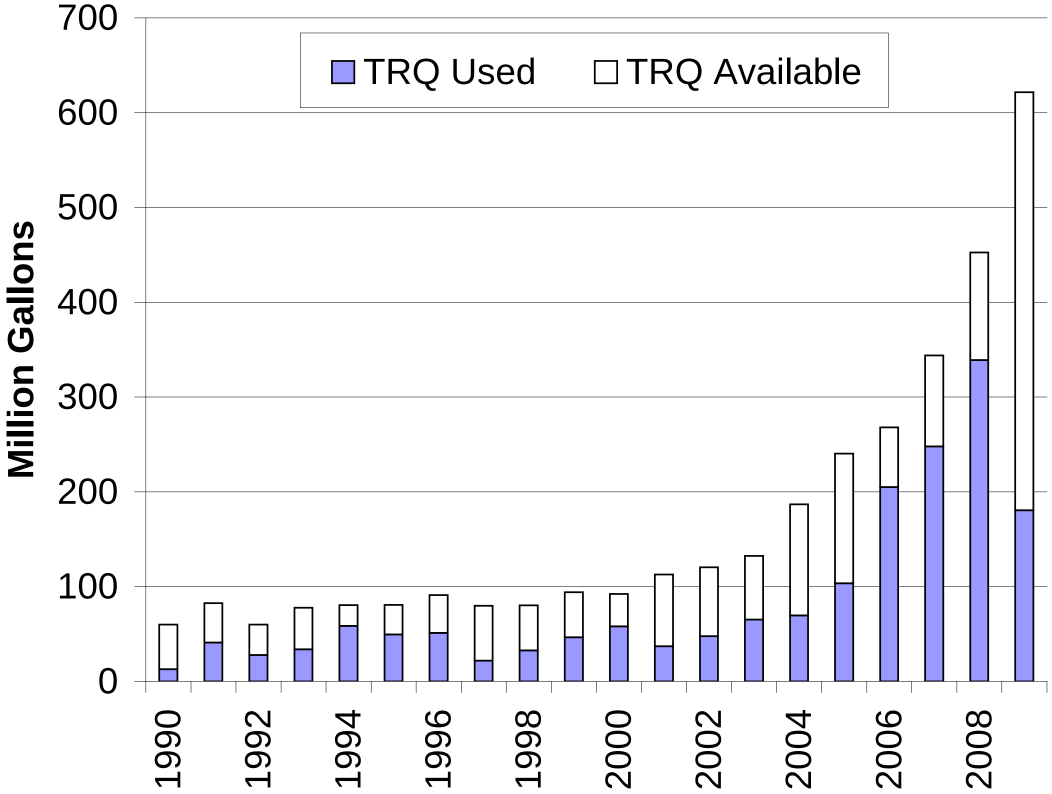
Under the Caribbean Basin Economic Recovery Act (CBERA), which created the CBI, countries in Central America and the Caribbean have had duty-free access to the United States since 1989 for ethanol produced from regional feedstocks. Although most analysts believe there is sufficient land available for sugarcane production in some CBI nations, there has been insufficient economic potential to spur sugarcane planting for ethanol production.[344] Ethanol derived from non-regional feedstocks has been limited to 7 percent of total U.S. ethanol consumption (based on figures from the previous year). There are also country-specific allocations for El Salvador (5.2 million gallons in first year (2006) and an annual increase of 1.3 million gallons per year, not to exceed 10% of CBI quota) and Costa Rica (31 million gallons annually) established by the U.S. Free Trade Agreement with Central America and the Dominican Republic (CAFTA-DR).[345] Since 2007, Costa Rica, El Salvador, Jamaica, Trinidad and Tobago, and the U.S. Virgin Islands are the only countries that have exported ethanol to the U.S. under the CBI quota.

Historically, the CBI nations have had little ethanol production capacity of their own but have supplemented it by importing hydrous Brazilian ethanol where it is further dehydrated before being re-exported to the U.S. duty-free. CBI countries have also relied on surplus wine alcohol from France, Italy, Spain and other Mediterranean countries in the past.[346] According to the United States International Trade Commission, the majority of fuel ethanol imports to the United States came through CBI countries between 1996 and 2003. However, in 2006, CBI ethanol imports to the U.S. totaled over 170 million gallons while imports to the U.S. from Brazil totaled 3 times that amount, or approximately 430 million gallons. This data indicates that in 2006 it was economical to import significant quantities of ethanol directly from other nations due to the withdrawal of MTBE and high oil prices. However, it is not clear on how much of this volume the tariff was paid, as there have been other means for importers to avoid the tariff.

In the past, companies have also imported ethanol from Brazil through a duty drawback.[347] The drawback is a loophole in the tax rules which allowed companies to import ethanol and then receive a rebate on taxes paid on the ethanol when jet fuel is sold for export within three years. The drawback considered ethanol and jet fuel as similar commodities (finished petroleum derivatives).[348,349] However, Senate Representative Charles Grassley from Iowa recently included a provision into the 2008 Farm bill that ended such refunds. The provision states that "any duty paid under subheading 9901.00.50 of the Harmonized Tariff Schedule of the United States on imports of ethyl alcohol or a mixture of ethyl alcohol may not be refunded if the exported article upon which a drawback claim is based does not contain ethyl alcohol or a mixture of ethyl alcohol."[350] The provision became effective on October 1, 2008 and companies have until October 1, 2010 to apply for a duty drawback on prior transactions. With the loophole closed, it is anticipated that there may be less ethanol directly exported from Brazil in the future.[351] World sugar prices are also attributing to a reduction in Brazilian imports.

CBI countries have not yet exceeded the tariff rate quotas (TRQs) for ethanol imports. The TRQ has been limited to 7 percent of total U.S. ethanol consumption (based on figures from the previous year). The fill rate, or percent of the TRQ used, has ranged from 22-77% between 1990 and 2009. See Figure 1.5-11. Thus, there is still considerable room for growth in CBI imported ethanol.

**Figure 1.5-11. U.S. Fuel Ethanol CBERA TRQ, 1990-2009***



*2009 TRQ Used data is preliminary. 2010 TRQ Available is 739.8.

In October 2003, the California Energy Commission (CEC) reported four active CBI ethanol dehydration plants, two in Jamaica, one in Costa Rica, and one in El Salvador. At the time, CEC concluded that reprocessing capacity was the limiting factor on CBI imports, with a total of 90 million gallons per year.[352] Since then, several companies have expanded plants or announced new plants as described below:

- *Jamaica*- In 2005, Petrojam Ethanol Limited (PEL), upgraded and expanded their ethanol dehydration plant in Jamaica to a capacity of 40 million .U.S gallons. Currently, the production of anhydrous (fuel grade) ethanol at the plant is based on a marketing agreement with the Brazilian company, Coimex Trading, where the feedstock - hydrous ethanol is supplied from Brazil.[353,354] Jamaica Broilers Group (JBG) launched fuel ethanol production at its 60 million gallon dehydration plant. The first shipment of 5.5 million gallons of ethanol , which arrived in June 2007, was converted to anhydrous ethanol for export to the U.S. JBG had a deal with Bauche Energy for the supply of 50 million gallons of hydrous ethanol out of Brazil for the first year of operation.[355] Jamaica

Ethanol Processing Ltd, which is ED & F Man's subsidiary on the island, has a small plant that dehydrates ethanol from Brazil at a capacity of 55 million gallons.

- *Costa Rica*- LAICA (cane co-op) has a plant currently dehydrating ethanol at 38 million gallons.[356]
- *El Salvador and Panama*- In 2004, it was reported that Cargill and Chevron Texaco had announced plans to construct new dehydration plants in El Salvador and Panama. These plants could produce 60 million gallons per year and between 50 and 100 million gallons per year, respectively.[357] Plants currently in operation include Gasohol de El Salvador (Liza/Vitol) at 100 million gallons per year and ARFS (CASA/Cargill/Crystalsev) at 60 million gallons per year.[358]
- *Trinidad*- EthylChem Inc. has reported plans to build an ethanol dehydration operation at the Petrotrin Refinery in Point-a-Pierre, a southern port city in Trinidad.[359] The cost to build the plant is estimated at $20 million.[360] It is probable, however, that not all the ethanol would be exclusively for U.S. consumption. According to Ron White, the executive director of Ethylchem, "While EthylChem intends to export the fuel to the United States the company is examining the possibility of shipping the product to other markets in the world".[361] Another company, Angostura Ltd., started processing ethanol in 2005.[362] The plant has an overall capacity of 100 million gallons per year, with 50 million gallons per year in the first phase.[363]
- *Others*- An idled ethanol plant in Haiti has attracted some investors and there are also projects in the works in Guyana, the Dominican Republic and Aruba. The U.S. Virgin Islands has one plant dehydrating ethanol at 100 million gallons per year capacity (Geonet).[364] A new ethanol dehydration plant is proposed to be built at the Bulk Terminal Facility near Spring Garden Highway in Barbados.[365] There is a proposal to build a US$36 million ethanol plant near Bridgetown, Barbados. The plant is expected to produce about 132 million gallons by refining ethanol imported from Brazil.[366]

In total, fuel ethanol plant capacity for dehydration in the Caribbean is estimated at 500 million gallons per year. Plans to expand total approximately 200 million gallons.[367] This means that there could be 700 million gallons per year of fuel ethanol capacity in the next few years.

Some stakeholders, however, have expressed concern that the CBI countries are not as stable for investment. Both Brazilian ethanol and European wine alcohol are susceptible to factors including availability, price fluctuations, trade regulations, currency movements and freight rates. Availability of European surplus wine alcohol has diminished since the World Trade Organization (WTO) placed limitations on export subsidies and has found new markets in Spain and Sweden.[368] CBI countries also need to compete for Brazilian ethanol. For example, Angostura's ethanol subsidiary, Trinidad Bulk Traders Ltd., was not profitable in 2006 because it could not get enough fuel from Brazil.[369]

There are other prohibitive factors to CBI ethanol production that exist. For instance, many of the CBI countries have no oil, natural gas or coal. Permitting is often a huge challenge and fresh water is typically scarce.[370]

In addition, increasing significantly beyond the 7% limit may be challenging. Few Caribbean countries are in a position to produce ethanol from domestic feedstocks such as sugarcane. Currently, all three plants exist in Central America (CATSA in Costa Rica, Pantleon Group in Guatemala, and Pellas Group in Nicaragua). Capacity for each plant is approximately 10 million gallons per year. The majority of this domestic fuel ethanol is shipped to the EU for fuel use rather than the U.S. due to higher opportunity prices and similar tariff free treatment.[371] In addition, the governments of Trinidad, St. Kitts and Barbados have already decided the sugar sectors of their islands are not worth further investment. Rum distillers such as Trinidad's Angostura and Jamaica's Appleton Ltd. have also had to import molasses from Fiji for their spirits.[372] Thus, it may take years before Caribbean countries are able to domestically produce large volumes of ethanol. As noted above, however, as dehydration capacity gets close to the U.S. CBI quota, processors may need to consider blending indigenous ethanol.

As a result of the economic benefit of shipping ethanol through CBI nations, we anticipate that the majority of the TRQ will be met in the future. If we assume that 90 percent of the TRQ is met and that total domestic ethanol (corn and cellulosic ethanol) consumed in 2021 was 19.2 Bgal (under the primary control case), then approximately 1.21 Bgal of ethanol could enter the U.S. through CBI countries in 2022.[XX] The rest of the Brazilian ethanol exports not entering the CBI will compete on the open market with the rest of the world demanding some portion of direct Brazilian ethanol. As shown in Table 1.5-22, to meet our advanced biofuel standard, we assumed 1.03 billion gallons of sugarcane ethanol would be imported directly to the U.S. in 2022. The total imported ethanol required by the Act was projected for each year based on the required volumes needed to meet the advanced biofuel standard after accounting for the volumes from cellulosic biofuel, biodiesel, and renewable diesel.

**Table 1.5-22.**
**Projected Contribution of Ethanol from CBI Countries and Direct Brazilian exports in 2022 (billion gallons)**

| Ethanol From CBI Countries | Ethanol Directly From Brazil | Total Imported Ethanol |
|---|---|---|
| 1.21 | 1.03 | 2.24 |

The amount of Brazilian ethanol available for direct shipment to the U.S. will be dependent on the biofuels mandates and goals set by other foreign countries (e.g., the EU, Japan, India, and China). Our estimates show that there could be a potential demand for imported ethanol of 4.4-14.3 billion gallons by 2020/2022 from these countries as noted in Section 1.5.2.1. This is due to the fact that some countries are unable to produce large volumes of ethanol because of e.g. land constraints or low production capacity. Therefore, unless Brazil or other countries increase biofuels production significantly, there may be a limited supply for imported ethanol to satisfy all foreign country mandates and goals.

### 1.5.3 Cellulosic Biofuel

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[XX] Total Domestic Ethanol is based on the amount needed to meet EISA (i.e. for the primary control case in 2021: 15 Bgal Corn Ethanol, 4.15 Cellulosic Ethanol)

The majority of the biofuel currently produced in the United States comes from plants processing first-generation feedstocks like corn, plant oils, sugarcane, etc. Non-edible cellulosic feedstocks have the potential to greatly expand biofuel production, both volumetrically and geographically. Research and development on cellulosic biofuel technologies has exploded over the last few years, and plants to commercialize a number of these technologies are already beginning to materialize. The $1.01/gallon tax credit for cellulosic biofuel that was introduced in the Food, Conservation, and Energy Act of 2008 ("2008 Farm Bill") and recently became effective, is also offering much incentive to this developing industry.[373] In addition to today's RFS2 program which sets aggressive goals for cellulosic biofuel production, the Department of Energy (DOE), Department of Agriculture (USDA), Department of Defense (DOD) and state agencies are helping to spur industry growth.

### 1.5.3.1 Current State of the Industry

There are a growing number of biofuel producers, biotechnology companies, universities and research institutes, start-up companies as well as refiners investigating cellulosic biofuel production. The industry is currently pursuing a wide range of feedstocks, conversion technologies and fuels. There is much optimism surrounding the long-term viability of cellulosic ethanol and other alcohols for gasoline blending. There is also great promise and growing interest in synthetic hydrocarbons like gasoline, diesel and jet fuel as "drop in" petroleum replacements. Some companies intend to start by processing corn or sugarcane and then transition to cellulosic feedstocks while others are focusing entirely on cellulosic materials. Regardless, cellulosic biofuel production is beginning to materialize.

We are currently aware of 36 small cellulosic biofuel plants operating in North America. This includes process development units with fuel production capabilities, pilot plants, demonstration plants, as well as commercial demonstration plants.[YY] These facilities are summarized by fuel type in Tables 1.5-23 and 1.5-24 below. The lists below do not include plants currently processing grains or sugars with plans to transition to cellulosic feedstocks in the future, e.g., Amyris, Gevo/ICM, and Virent.[ZZ] However, we will continue to track these companies during future cellulosic biofuel assessments.

Regardless of their size, the main focus at these facilities is research and development, not commercial production. As shown below, most of the plants are rated at less than 250,000 gallons of cellulosic biofuel per year and that's if they were operated at capacity. However, most only operate intermittently for the purpose of demonstrating that the technologies can be used to produce transportation fuels. As such, some don't even report production capacities. The industry as a whole is still working to increase efficiency, improve yields, reduce costs and prove

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[YY] Based on research of information available on the public domain and follow-up correspondence with cellulosic biofuel companies.

[ZZ] Both Amyris and ICM have received federal funding to further their cellulosic biofuel efforts. On January 29, 2008, DOE announced that it had awarded ICM a $40 million grant to help build a small cellulosic ethanol plant at an existing corn ethanol plant in St. Joseph, MO. The company is currently piloting butanol production from corn with Gevo. On December 4, 2009, DOE and USDA awarded ICM with another $25 million to further cellulosic ethanol production at the St. Joseph plant. In the same announcement, DOE and USDA awarded Amyris with a $25 million grant to help further cellulosic research at its pilot plant in Emmeryville, CA.

to the public, as well as investors, that cellulosic biofuel is both technologically and economically feasible.

## Table 1.5-23. Current Cellulosic Alcohol Plants

| Company/Plant Name | Plant Location | Plant Type[a] | Max Cap (MGY) | Online Date | Cell. Biofuel | Cell. Tech.[b] | Cell. Feedstocks[c] | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | AR | EC | W | UW |
| Abengoa Bioenergy Corporation[d] | York, NE | Pilot | 0.02 | Sep-07 | Ethanol | Bio | X | X | | |
| AE Biofuels | Butte, MT | Demo | 0.15 | Aug-08 | Ethanol | Bio | X | X | | |
| Arkenol Technology Center | Orange, CA | Pilot | N/A | 1994 | Ethanol | Bio | X | | | |
| Auburn University / Masada | Auburn, AL | Pilot | N/A | 1995 | Ethanol | Bio | | | X | |
| Chemrec & Weyerhaeuser | New Bern, NC | Pilot | N/A | 1996 | Ethanol | Thermo | | | X | |
| ClearFuels / Hawaii Natural Energy Institute | Honolulu, HI | Pilot | N/A | 2004 | Ethanol | Thermo | X | | | |
| Cobalt Biofuels | Mountainview, CA | Pilot | 0.01 | N/A | Butanol | Bio | X | | X | |
| Cornell University Biofuels Research Laboratory | Ithaca, NY | Pilot | N/A | Jan-09 | Ethanol | Bio | | X | X | |
| Coskata[e] | Warrenville, IL | Pilot | N/A | Mar-08 | Ethanol | Thermo | X | | | |
| Coskata[e] | Madison, PA | Demo | 0.04 | Oct-09 | Ethanol | Thermo | X | X | X | X |
| DOE National Renewable Energy Laboratory | Golden, CO | Pilot | N/A | 2001 | Ethanol | Bio | X | | | |
| Enerkem | Sherbrooke (CAN) | Pilot | N/A | 2003 | Ethanol | Thermo | | | X | X |
| Fiberight[f] | Lawrenceville, VA | Demo (C) | N/A | 2005 | Ethanol | Bio | | | | X |
| Fulcrum Bioenergy - Turning Point Ethanol Plant | Durham, NC | Demo | N/A | Mar-09 | Ethanol | Thermo | | | | X |
| Gulf Coast Energy | Livingston, AL | Demo | 0.20 | Sep-08 | Ethanol | Thermo | | | | X |
| INEOS Bio (formerly BRI)[e] | Fayetteville, AR | Pilot | 0.04 | 1998 | Ethanol | Thermo | X | | X | X |
| Iogen Corporation | Ottawa (CAN) | Pilot | N/A | 1985 | Ethanol | Bio | X | | X | |
| Iogen Corporation | Ottawa (CAN) | Demo (C) | 0.50 | 2004 | Ethanol | Bio | X | | | |
| KL Energy Corp / WBE | Upton, WY | Demo (C) | 1.50 | Sep-07 | Ethanol | Bio | | | X | |
| Lignol Energy | Burnaby (CAN) | Pilot | N/A | Jun-09 | Ethanol | Bio | X | | X | |
| Mascoma Corporation | Rome, NY | Pilot | 0.20 | Dec-08 | Ethanol | Bio | | | X | |
| Pan Gen Global (formerly Colusa Biomass) | Colusa County, CA | Pilot | N/A | 1995 | Ethanol | Bio | X | | | |
| Pearson Technologies Inc. | Aberdeen, MS | Pilot | N/A | 2001 | Ethanol | Thermo | X | | X | |
| POET Project Bell[d] | Scotland, SD | Pilot | 0.02 | Nov-08 | Ethanol | Bio | | | X | |
| PureVision Technology, Inc.[f] | Fort Lupton, CO | PDU | N/A | Mar-09 | Ethanol | Bio | X | | X | |
| Range Fuels K2A Optimization Plant | Broomfield, CO | Pilot | N/A | Mar-09 | Ethanol | Thermo | | | X | |
| SunOpta BioProcess Inc. | Norval (CAN) | Pilot | N/A | 2003 | Ethanol | Bio | X | | | |
| Verenium | Jennings, LA | Pilot | 0.05 | 2006 | Ethanol | Bio | X | | | |
| Verenium | Jennings, LA | Demo | 1.40 | Feb-09 | Ethanol | Bio | X | X | X | |

[a] PDU = Process development unit, Pilot = pilot-scale plant, Demo = demonstration-level plant, Demo (C) = Commercial demonstration plant.

[b] Conversion technology. Bio = Biochemical, Thermo = Thermochemical.

[c] Cellulosic feedstocks. AR = Ag residues, EC = Energy crops, W = Wood waste, chips, mill waste, etc., UW = Urban waste including sorted MSW and C&D debris.

[d] Cellulosic ethanol plant is co-located with an existing corn ethanol plant.

[e] Plant also processes non-cellulosic/renewable feedstocks, e.g., natural gas, coal.

[f] Plant is not currently operational and/or producing fuel at this time.

## Table 1.5-24. Current Cellulosic Hydrocarbon Fuel & Pyrolysis Oil Plants

| Company/Plant Name | Plant Location | Plant Type[a] | Max Cap (MGY) | Online Date | Cell. Biofuel | Cell. Tech.[b] | Cell. Feedstocks[c] | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | | | AR | EC | W | UW |
| Bell Bio-Energy[d] | Fort Stewart, GA | Pilot | 0.01 | Dec-08 | Diesel | Bio | | | X | X |
| Cello Energy[d] | Bay Minette, AL | Demo (C) | 20.00 | Dec-08 | Diesel | Cat | X | | X | |
| Clearfuels / Rentech[e] | Commerce City, CO | PDU | N/A | 2008 | Diesel, Jet | Thermo | X | | X | |
| Dynamotive | West Lorne (CAN) | Demo (C) | 3.55 | N/A | Py Oil | Thermo | | | X | |
| Dynamotive / Evolution Biofuels | Guelph (CAN) | Demo (C) | 5.46 | Sep-07 | Py Oil | Thermo | | | X | |
| Terrabon Advanced Biofuels Research Center | Bryan, TX | Pilot | 0.13 | Apr-09 | Gasoline | Bio | | X | X | X |
| ThermoChem Recovery International (TRI) | Durham, NC | Pilot | 0.02 | Jun-09 | Diesel | Thermo | X | X | X | |

[a] PDU = Process development unit, Pilot = pilot-scale plant, Demo (C) = Commercial demonstration plant.

[b] Conversion technology. Bio = Biochemical, Cat = Catalytic depolymerization, Thermo = Thermochemical.

[c] Cellulosic feedstocks. AR = Ag residues, EC = Energy crops, W = Wood waste, chips, mill waste, etc., UW = Urban waste including sorted MSW and C&D debris.

[d] Plant is not currently operational and/or producing fuel at this time.

[e] Currently in the process of expanding natural gas-based PDU to a pilot plant that can process biomass feedstocks.

As shown in Tables 1.5-23 and 1.5-24, today's cellulosic biofuel plants are run by a combination of academic, government, and private organizations. Some of the privately-owned companies are existing biofuel producers, but many are start-up companies entering the industry for the first time. The following companies were awarded federal funding to help build their small plants and/or facilitate cellulosic research – Bell Bio-Energy ($1.1 million from the Department of Defense), Clearfuels / Rentech ($2.5 million from the DOE) and Verenium ($10 million from the DOE).[374]

As indicated above, a variety of feedstocks are being investigated for cellulosic biofuel production. There is a great deal of interest in urban waste (MSW and C&D debris) because it is virtually free and abundant in many parts of the country, including large metropolitan areas where the bulk of fuel is consumed. There is also a lot of interest in agricultural residues (corn stover, rice and other cereal straws) and wood (forest thinnings, wood chips, pulp and paper mill waste, and yard waste). However, researchers are still working to find viable harvesting and storage solutions. Others are investigating the possibility of growing dedicated energy crops for cellulosic biofuel production, e.g., switchgrass, energy cane, sorghum, poplar, miscanthus and other fast-growing trees. While these crops have tremendous potential, many are starting with the feedstocks that are available today with the mentality that once the industry has proven itself, it will be easier to secure growing contracts and start producing energy crops. For more information on cellulosic feedstock availability, refer to Section 1.1.2.

The industry is also pursuing a number of different cellulosic conversion technologies and biofuels. Most of the technologies fall into one of two categories: biochemical or thermochemical. Biochemical conversion involves the use of acids and/or enzymes to hydrolyze cellulosic materials into fermentable sugars and lignin. Thermochemical conversion involves the use of heat to convert biomass into synthesis gas or pyrolysis oil for upgrading. A third technology pathway is emerging that involves the use of catalysts to depolymerize or reform the feedstocks into fuel. The technologies currently being considered are capable of producing cellulosic alcohols or hydrocarbons for the transportation fuel market. Many companies are also researching the potential of co-firing biomass to produce plant energy in addition to biofuels. For a more in-depth discussion on cellulosic technologies, refer to Section 1.4.3.

### 1.5.3.2 Setting the 2010 Standard

The Energy Independence and Security Act (EISA) set aggressive cellulosic biofuel targets beginning with 100 million gallons in 2010. However, EISA also supplied EPA with cellulosic biofuel waiver authority. For any calendar year in which the projected cellulosic biofuel production is less than the minimum applicable volume, EPA can reduce the standard based on the volume expected to be available that year. EPA is required to set the annual cellulosic standard by November 30th each year and should consider the annual estimate made by EIA by October 31st of each year. We are setting the 2010 standard as part of this final rule.

Setting the cellulosic biofuel standard for 2010 represents a unique challenge. As discussed above, the industry is currently characterized by a wide range of companies mostly focused on research, development, demonstration, and financing their developing technologies. In addition, while we are finalizing a requirement that producers and importers of renewable fuel provide us with production outlook reports detailing future supply estimates (refer to §80.1449), we do not have the benefit of this valuable cellulosic supply information for setting the 2010 standard. Finally, since today's cellulosic biofuel production potential is relatively small, and the number of actual potential producers few (as described in more detail below), the overall volume for 2010 can be heavily influenced by new developments, either positive or negative associated with even a single company, which can be very difficult to predict. This is evidenced by the magnitude of changes in cellulosic biofuel projections and the potential suppliers of these fuels since the proposal.

In the proposal, we did a preliminary assessment of the cellulosic biofuel industry to arrive at the conclusion that it was possible to uphold the 100 million gallon standard in 2010 based on anticipated production. At the time of our April 2009 NPRM assessment, we were aware of a handful of small pilot and demonstration plants that could help meet the 2010 standard, but the largest volume contributions were expected to come from Cello Energy and Range Fuels.

Cello Energy had just started up a 20 million gallon per year (MGY) cellulosic diesel plant in Bay Minette, AL. EPA staff visited the facility twice in 2009 to confirm that the first-of-its-kind commercial plant was mechanically complete and poised to produce cellulosic biofuel. It was assumed that start-up operations would go as planned and that the facility would be operating at full capacity by the end of 2009 and that three more 50 MGY cellulosic diesel plants planned for the Southeast could be brought online by the end of 2010.

At the time of our assessment, we were also anticipating cellulosic biofuel production from Range Fuels' first commercial-scale plant in Soperton, GA. The company received a $76 million grant from DOE to help build a 40 MGY wood-based ethanol plant and they broke ground in November 2007. In January 2009, Range was awarded an $80 million loan guarantee from USDA.[AAA] With the addition of this latest capital, the company seemed well on its way to completing construction of its first 10 MGY phase by the end of 2009 and beginning production in 2010.

Since our April 2009 industry assessment there have been a number of changes and delays in production plans due to technological, contractual, financial and other reasons. Cello Energy and Range Fuels have delayed or reduced their production plans for 2010. Some of the small plants expected to come online in 2010 have pushed back production to the 2011-2012 timeframe, e.g., Clearfuels Technology, Fulcrum River Biofuels, and ZeaChem. Alltech/Ecofin and RSE Pulp & Chemical, two companies that were awarded DOE funding back in 2008 to build small-scale biorefineries appear to be permanently on hold or off the table. In addition, Bell Bio-Energy, a company that received DOD funding has since abandoned plans to build additional cellulosic diesel plants at U.S. military bases.[BBB]

At the same time, there has also been an explosion of new companies, new business relationships, and new advances in the cellulosic biofuel industry. Keeping track of all of them

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[AAA] For more information on federal support for biofuels, refer to Section 1.5.3.3.

[BBB] Bell Bio-Energy is currently investigating other location for turning MSW into diesel fuel according to an October 14, 2009 conversation with JC Bell.

is a challenge in and of itself as the situation can change on a daily basis. EIA recently provided EPA with their first cellulosic biofuel supply estimate required under CAA section 211(o)(7)(D)(i). In a letter to the Administrator dated October 29, 2009, they arrived at a 5.04 million gallon estimate for 2010 based on publicly available information and assumptions made with respect production capacity utilization.[375] A summary of the plants they considered is shown below in Table 1.5-25.

**Table 1.5-25.**
**EIA's Projected Cellulosic Biofuel Plant Production Capacities for 2010**

| Online | Company | Location | Product | Capacity (million gallons) | Expected Utilization (%) | Production (million gallons)[3] |
|---|---|---|---|---|---|---|
| 2007 | KL Process Design | Upton, WY | Ethanol | 1.5 | 10 | 0.15 |
| 2008 | Verenium | Jennings, LA | Ethanol | 1.4 | 10 | 0.14 |
| 2008 | Terrabon | Bryan, TX | Bio-Crude | 0.93 | 10 | 0.09 |
| 2010 | Zeachem | Boardman, OR | Ethanol | 1.5 | 10 | 0.15 |
| 2010 | Cello Energy | Bay Minette, AL | Diesel | 20.0 | 10[1] | 2.00 |
| 2010 | Range Fuels | Soperton, GA | Ethanol | 5.0[2] | 50 | 2.5 |
|  | **Total** |  |  | **30.35** |  | **5.04** |

Notes: 1. Cello Energy is assigned a 10-percent utilization factor as they have not been able to run on a continuous basis long enough to apply for a Synthetic Minor Operating Permit or produce significant amounts of fuel during 2009. 2. It is estimated that only half the 2010 projected capacity (10 million gallons per year) will be a qualified fuel. 3. The production from these facilities in 2009 is not surveyed by EIA or EPA.

In addition to receiving EIA's information and coordinating with them and other offices in DOE, we have initiated meetings and conversations with over 30 up-and-coming advanced biofuel companies to verify publicly available information, obtain confidential business information, and better assess the near-term cellulosic biofuel production potential for use in setting the 2010 standard. What we have found is that the cellulosic biofuel landscape has continued to evolve. Based on information obtained, not only do we project significantly different production volumes on a company-by-company basis, but the list of potential producers of cellulosic biofuel in 2010 is also significantly different than that identified by EIA.

Overall, our industry assessment suggests that it is difficult to rely on commercial production from small pilot or demonstration-level plants. The primary purpose of these facilities is to prove that a technology works and demonstrate to investors that the process is capable of being scaled up to support a larger commercial plant. Small plants are cheaper to build to demonstrate technology than larger plants, but the operating costs ($/gal) are higher due to their small scale. As a result, it's not economical for most of these facilities to operate continuously. Most of these plants are regularly shut down and restarted as needed as part of the research and development process. Due to their intermittent nature, most of these plants operate at a fraction of their rated capacity, some less than the 10% utilization rate assumed by EIA. In addition, few companies plan on making their biofuel available for commercial sale.

However, there are at least two cellulosic biofuel companies currently operating demonstration plants in the U.S. and Canada that could produce fuel commercially in 2010. The first is KL Energy Corporation, a company we considered for the NPRM with a 1.5 MGY cellulosic ethanol plant in Upton, WY. This plant was considered by EIA and is included in their final plant summary presented in Table 1.5-25. The second is Iogen's cellulosic ethanol plant in Ottawa, Canada with a 0.5 MGY capacity. Iogen's commercial demonstration plant was referenced by EIA as a potential foreign source for cellulosic biofuel but was not included in their final table. In addition to these online demonstration plants, there are three additional companies not on EIA's list that are currently building demonstration-level cellulosic biofuel plants that are scheduled to come online in 2010. This includes DuPont Danisco Cellulosic Ethanol and Fiberight, companies currently building demonstration plants in the U.S. and Enerkem, a company building a demonstration plant in Canada. Cello Energy's plant in Bay Minette, AL continues to offer additional potential for cellulosic biofuel in 2010. And finally, Dynamotive, a company that currently has two biomass-based pyrolysis oil production plants in Canada is another potential source of cellulosic biofuel in 2010. All seven aforementioned companies are discussed in greater detail below along with Range Fuels.

KL Energy Corporation (KL Energy), through its majority-owned Western Biomass Energy, LLC (WBE) located in Upton, WY, is designed to convert wood products and wood waste products into ethanol. Since the end of construction in September 2007, equipment commissioning and process revisions continued until the October 2009 startup. The plant was built as a 1.5 MGY demonstration plant and was designed to both facilitate research and operate commercially. It is KL Energy's intent that WBE's future use will involve the production and sale of small but commercial-quality volumes of ethanol and lignin co-product. The company's current 2010 goal is for WBE to generate RINs under the RFS2 program.[CCC]

Iogen is responsible for opening the first commercial demonstration cellulosic ethanol plant in North America. Iogen's plant located in Ottawa, Canada has been producing cellulosic ethanol from wheat straw since 2004. Like KL Energy, Iogen has slowly been ramping up production at its 0.5 MGY plant. According to the company's website, they produced approximately 24,000 gallons in 2004 and 34,000 gallons in 2005. Production dropped dramatically in 2006 and 2007 but came back strong with 55,000 gallons in 2008. Iogen recently produced over 150,000 gallons of ethanol from the demonstration plant in 2009. Iogen also recently became the first cellulosic ethanol producer to sell its advanced biofuel at a retail service station in Canada. Their cellulosic ethanol was blended to make E10 available for sale to consumers at an Ottawa Shell station.[376] Iogen also recently announced plans to build its first commercial scale plant in Prince Albert, Saskatchewan in the 2011/2012 timeframe. Based on the company's location and operating status, Iogen certainly has the potential to participate in the RFS2 program. However, at this time, we are not expecting them to import any cellulosic ethanol into the U.S. in 2010.[DDD]

DuPont Danisco Cellulosic Ethanol, LLC (DDCE), a joint venture between Dupont and Danisco, is another potential source for cellulosic biofuel in 2010. DDCE received funding from the State of Tennessee and the University of Tennessee to build a small 0.25 MGY demonstration plant in Vonore, TN to pursue switchgrass-to-ethanol production. According to

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[CCC] Based on information provided by Lori Litzen, Environmental Permit Engineer at KL Energy on December 10, 2009.

[DDD] Based on website information, comments submitted in response to our proposal, and a follow-up phone call with Iogen Executive VP, Jeff Passmore on December 17, 2009.

DDCE, construction commenced in October 2008 and the plant is now mechanically complete and undergoing start-up operations. The facility is scheduled to come online by the end of January and the company hopes to operate at or around 50% of production capacity in 2010. According to the DDCE, the objective in Vonore is to validate processes and data for commercial scale-up, not to make profits. However, the company does plan to sell the cellulosic ethanol it produces.[EEE]

Enerkem is another company pursuing cellulosic ethanol production. The Canadian-based company was recently announced as a recipient of a joint $50 million grant from DOE and USDA to build a 10 MGY woody biomass-to-ethanol plant in Pontotoc, MS.[377] The U.S. plant is not scheduled to come online until 2012, but Enerkem is currently building a 1.3 MGY demonstration plant in Westbury, Quebec. According to the company, plant construction in Westbury started in October 2007 and the facility is currently scheduled to come online around the middle of 2010. While it's unclear at this time whether the cellulosic ethanol produced will be exported to the United States, Enerkem has expressed interest in selling its fuel commercially.[FFF]

Additional cellulosic biofuel could come from Fiberight, LLC (Fiberight) in 2010. We recently became aware of this start-up company and contacted them to learn more about their process and cellulosic biofuel production plans. According to Fiberight, they have been operating a pilot-scale facility in Lawrenceville, VA for three years. They have developed a proprietary process that not only fractionates MSW but biologically converts the non-recyclable portion into cellulosic ethanol and biochemicals. Fiberight recently purchased a shut down corn ethanol plant in Blairstown, IA and plans to convert it to become MSW-to-ethanol capable. According to the company, construction is currently underway and the goal is to bring the 2 MGY demonstration plant online by February or March, 2010. If the plant starts up according to plan, the company intends on making cellulosic ethanol commercially available in 2010 and generating RINS under the RFS2 program. Fiberight's long-term goal is to expand the Blairstown plant to a 5-8 MGY capacity and build other small commercial plants around the country that could convert MSW into fuel.[GGG]

Cello Energy, a company considered in the proposal, continues to be another viable source for cellulosic biofuel in 2010. Despite recent legal issues which have constrained the company's capital, Cello Energy is still pursuing cellulosic diesel production. According to the company, they are currently working to resolve materials handling and processing issues that surfaced when they attempted to scale up production to 20 MGY from a previously operated demonstration plant. As of November 2009, they were waiting for new equipment to be ordered and installed which they hoped would allow for operations to be restarted as early as February or March, 2010. Cello's other planned commercial facilities are currently on hold until the Bay Minette plant is operational.[HHH]

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[EEE] Based on a December 16, 2009 telephone conversation with DDCE Director of Corporate Communications, Jennifer Hutchins and follow-up e-mail correspondence.

[FFF] Based on an October 14, 2009 meeting with Enerkem and follow-up telephone conversation with VP of Government Affairs, Marie-Helene Labrie on December 14, 2009.

[GGG] Based on a December 15, 2009 telephone conversation with Fiberight CEO, Craig Stuart-Paul and follow-up e-mail correspondence.

[HHH] Based on a November 9, 2009 telephone conversation with Cello Energy CEO, Jack Boykin.

Another potential supplier of cellulosic biofuel is Dynamotive Energy Systems (Dynamotive) headquartered in Vancouver, Canada. As shown in Table 1.5-24, Dynamotive currently has two plants in West Lorne and Guelph, Ontario, Canada, that produce biomass-based pyrolysis oil (also known as "BioOil") for industrial applications. The BioOil production capacity between the two plants is estimated at around 9 MGY, but both plants are currently operating at a fraction of their rated capacity.[III] However, according to a recent press release, Dynamotive has contracts in place to supply a U.S.-based client with at least nine shipments of BioOil in 2010. If Dynamotive's BioOil is used as heating oil or upgraded to transportation fuel, it could potentially count towards meeting the cellulosic biofuel standard in 2010.

As for the Range Fuels plant, construction of phase one in Soperton, GA, is about 85% complete, with start-up planned for mid-2010. However, there have been some changes to the scope of the project that will limit the amount of cellulosic biofuel that can be produced in 2010. The initial capacity has been reduced from 10 to 4 million gallons per year. In addition, since they plan to start up the plant using a methanol catalyst they are not expected to produce qualifying renewable fuel in 2010. During phase two of their project, currently slated for mid-2012, Range plans to expand production at the Soperton plant and transition from a methanol to a mixed alcohol catalyst. This will allow for a greater alcohol production potential as well as a greater cellulosic biofuel production potential.[JJJ]

Overall, our most recent industry assessment suggests that there are six companies that could potentially produce cellulosic biofuel next year. Together these seven plants, summarized in Table 1.5-26, could have over 30 MGY of cellulosic biofuel plant capacity online by the end of 2010. However, the actual volume of cellulosic biofuel realized under the RFS2 program will likely be much lower, as explained in more detail below.

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[III] According to Dynamotive's website, the Guelph plant has a capacity to convert 200 tonnes of biomass into BioOil per day. If all modules are fully operational, the plant has the ability to process 66,000 dry tons of biomass per year with an energy output equivalent to 130,000 barrels of oil. The West Lorne plant has a capacity to convert 130 tonnes of biomass into BioOil per day (which, if proportional to the Guelph plant, translates to an energy-equivalent of 84,500 barrels of oil. According to a November 3, 2009 press release, Dynamotive has contracts in place to supply a U.S.-based client with at least nine shipments of BioOil in 2010.

[JJJ] Based on a November 5, 2009 telephone conversation with Range Fuels VP of Government Affairs, Bill Schafer.

## Table 1.5-26
## EPA's Cellulosic Biofuel Plant Assessment – Projected Plants/Capacity Online by End of 2010

| Company/Plant Name | Plant Location | Plant Type | Max Cap (MGY) | Operational Status | Proj. Op. Date | Cell. Biofuel | Cellulosic Feedstocks |
|---|---|---|---|---|---|---|---|
| Cello Energy | Bay Minette, AL | Demo (C) | 20.00 | Currently Off-Line | Mar-10 | Diesel | Wood chips, hay |
| DuPont Danisco (DDCE) | Vonore, TN | Demo | 0.25 | Undergoing Start-Up | Jan-10 | Ethanol | Corn cobs then switchgrass |
| Dynamotive | West Lorne (CAN) | Demo (C) | 3.55 | On-Line |  | Py Oil | Waste wood |
| Dynamotive | Guelph (CAN) | Demo (C) | 5.46 | On-Line |  | Py Oil | Waste wood, wood chips |
| Enerkem | Westbury (CAN) | Demo | 1.30 | Under Construction | Jun-10 | Ethanol | Treated wood |
| Fiberight | Blairstown, IA | Demo (C) | 2.00 | Under Construction | Mar-10 | Ethanol | Sorted MSW |
| KL Energy Corp / WBE | Upton, WY | Demo (C) | 1.50 | On-Line |  | Ethanol | Wood chips |

Since most of the plants in Table 1.5-26 are still under construction today, the amount of cellulosic biofuel produced in 2010 will be contingent upon when and if these plants come online and whether the projects get delayed due to funding or other reasons. In addition, based on our discussions with the developing industry, it is clear that we cannot count on demonstration plants to produce at or near capacity in 2010, or in their first few years of operation for that matter. The amount of cellulosic biofuel actually realized will depend on whether the process works, the efficiency of the process, and how regularly the plant is run. As mentioned earlier, most small plants, including commercial demonstration plants, are not operated continuously. As such, we cannot base the standard on these plants running at capacity - at least until the industry develops further and proves that such rates are achievable. We currently estimate that production from first-of-it's kind plants could be somewhere in the 25-50% range in 2010. Together, the implementation timelines and anticipated production levels of the plants described above brings the cellulosic biofuel supply estimate to somewhere in the 6-13 million gallon range for 2010.

In addition, it is unclear how much was can rely on Canadian plants for cellulosic biofuel in 2010. Although we currently receive some conventional biofuel imports from Canada and many of the aforementioned Canadian companies have U.S. markets in mind, the country also has its own renewable fuel initiatives that could keep much of the cellulosic biofuel produced from coming to the United States, e.g., Iogen. Finally, it's unclear whether all fuel produced by these facilities will qualify as cellulosic biofuel under the RFS2 program. Several of the companies are producing fuels or using feedstocks which may not in fact qualify as cellulosic biofuel once we receive their detailed registration information. Factoring in these considerations, the cellulosic biofuel potential from the seven plants summarized in Table 1.5-26 could result in several different production scenarios in the neighborhood of the recent EIA estimate. We believe this estimate of 5 million gallons or 6.5 ethanol-equivalent million gallons represents a reasonable yet achievable level for the cellulosic biofuel standard in 2010 considering the degree of uncertainty involved with setting the standard for the first year. As mentioned earlier, we believe standard setting will be easier in future years once the industry matures, we start receiving production outlook reports and there is less uncertainty regarding feasibility of cellulosic biofuel production.

### 1.5.3.3 Current Outlook for 2011 and Beyond

Since the proposal, we have also learned about a number of other cellulosic biofuel projects in addition to those described above. This includes commercial U.S. production plans by Coskata, Enerkem and Vercipia. However, production isn't slated to begin until 2011 or later and the same is true for most of the other larger plants we're aware of that are currently under development. Nonetheless, while cellulosic biofuel production in 2010 may be limited, it is remarkable how much progress the industry has made in such a short time, and there is a tremendous growth opportunity for cellulosic biofuels over the next several years.

Most of the cellulosic biofuel companies we've talked to are in different stages of proving their technologies. Regardless of where they are at, many have fallen behind their original commercialization schedules. As with any new technology, there have been delays associated with scaling up capacity, i.e., bugs to work out going from pilot to demonstration to commercialization. However, most are saying it's not the technologies that are delaying commercialization, it is lack of available funding. Obtaining capital has been very challenging given the current recession and the banking sector's financial difficulties. This is especially true for start-up companies that do not have access to capital through existing investors, plant profits, etc. From what we understand, banks are looking for cellulosic companies to be able to show that their plants are easily “scalable” or expandable to commercial size. Many are only considering companies that have built plants to one-tenth of commercial scale and have logged many hours of continuous operation.

The government is currently trying to help in this area. To date, the Department of Energy (DOE) and the Department of Agriculture (USDA) have allocated over $720 million in federal funding to help build pilot and demonstration-scale biorefineries employing advanced technologies in the United States.[KKK,378] The largest installment from Recovery Act funding was recently announced on December 4, 2009 and includes funding for a series of larger commercial demonstration plants including cellulosic ethanol projects by Enerkem and INEOS New Planet BioEnergy, LLC. DOE has also issued grants to help fund some of the first commercial cellulosic biofuel plants. Current recipients include Abengoa Bioenergy, BlueFire Ethanol[LLL] and POET Biorefining in addition to Range Fuels.[379] The DOE is also in the process of issuing loan guarantees.

The Energy Policy Act of 2005 (EPAct) authorized DOE to issue loan guarantees to eligible projects that "avoid, reduce, or sequester air pollutants or anthropogenic emissions of greenhouse gases" and "employ new or significantly improved technologies as compared to technologies in service in the United States at the time the guarantee is issued."[380] On October 4, 2007, DOE issued final regulations for its loan guarantee program and invited 16 pre-applicants to submit applications for federal support of innovative clean energy projects. Five of the pre-applicants are/were pursuing cellulosic biofuel production.[381]

Passage of the Recovery Act in 2009 created a new Section 1705 under Title XVII of the Energy Policy Act of 2005 for the rapid deployment of renewable energy projects and related manufacturing facilities, electric power transmission projects and leading edge biofuels projects that commence construction before September 30, 2011.[382] On December 7, 2009, Energy Secretary Steven Chu announced the issue of a final rule amending the Department of Energy’s regulations for its Loan Guarantee Program.[383] The revised rule will allow for increased participation in the program by financial institutions and other investors and enable the support of more innovative energy technologies in the United States. Although, to date, DOE has issued a number of solicitations and invited pre-applicants to submit full applications, no cellulosic

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[KKK] On January 29, 2008 DOE announced that it would provide $114 million to fund 4 small scale cellulosic biorefineries. On April 18, 2008, DOE announced that it would provide another $86 million to help fund three additional small-scale plants. On July 14, 2008, DOE announced another $40 million to help fund two more small cellulosic plants. On December 4, 2009, DOE and USDA announced that up to $483 million would be made available to fund 14 pilot-scale and 4 demonstration-scale biorefineries across the country, the majority of which are pursuing cellulosic biofuel production.

[LLL] Although BlueFire is still working on obtaining financing to build its first demonstration plant, it has received two installments of federal funding towards its first planned commercial-scale plant. The 19 MGY plant in Fulton, MS (originally planned for Southern California) was awarded $40 million from DOE on February 28, 2008 and another $81.1 million from DOE and USDA on December 4, 2009.

biofuel companies have been issued loan guarantees at this time.[MMM] However, the USDA has begun issuing loan guarantees under the 2008 Farm Bill (explained in more detail below).

The Farm Bill is assisting the cellulosic biofuel industry in many ways. First, it modified the $0.51/gal alcohol blender credit to give preference to ethanol and other biofuels produced from cellulosic feedstocks. Effective January 1, 2009, corn ethanol receives a reduced tax credit of $0.45/gal while cellulosic biofuel earns a credit of $1.01/gal.[NNN] In addition, the Farm Bill contains provisions that enable USDA to assist with the commercialization of second-generation biofuels, explained in more detail below.

Section 9003, also known as the Biorefinery Assistance Program, promotes the development of new and emerging technologies for the production of advanced biofuels - defined as fuels that are not produced from food sources. The program provides loan guarantees to develop, construct and retrofit viable commercial-scale biorefineries producing advanced biofuels. The maximum loan guarantee is $250 million per project. The program is designed to create energy-related jobs and economic development in rural America. On January 16, 2009, the USDA Rural Development approved its first ever loan guarantee to Range Fuels.[384] As mentioned earlier, Range received an $80 million loan from USDA to help build its Soperton, GA plant.[OOO] Section 9004 of the 2008 Farm Bill provides payments to biorefineries to replace fossil fuels with renewable biomass. Section 9005 provides payments to producers to support and ensure production of advanced biofuels. And finally, Section 9008 provides competitive grants, contracts and financial assistance to enable eligible entities to carry out research, development, and demonstration of biofuels and biomass-based based products.

In addition to helping fund a series of small cellulosic biofuel plants, the DOE and USDA are helping to fund critical research to help make cellulosic biofuel production more commercially viable. In March 2007, DOE awarded $23 million in grants to four companies and one university to develop more efficient microbes for ethanol refining.[385] In June 2007, DOE and USDA awarded $8.3 million to 10 universities, laboratories, and research centers to conduct genomics research on woody plant tissue for bioenergy.[386] Later that same month, DOE announced its plan to spend $375 million to build three bioenergy research centers dedicated to accelerating research and development of cellulosic ethanol and other biofuels. The centers, which will each focus on different feedstocks and biological research challenges, will be located in Oak Ridge, TN, Madison, WI, and Berkeley, CA.[387] In December 2007, DOE awarded $7.7 million to one company, one university, and two research centers to demonstrate the thermochemical conversion process of turning grasses, stover, and other cellulosic materials into biofuel.[388]

In February 2008, DOE awarded another $33.8 million to three companies and one research center to support the development of commercially-viable enzymes to support cellulose hydrolysis, a critical step in the biochemical breakdown of cellulosic feedstocks.[389] In March

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[MMM] To the best of our knowledge based on an assessment of DOE press releases.

[NNN] Refer to Part II, Subparts A and B (Sections 15321 and 15331).

[OOO] USDA also recently issued a $54.5 million loan guarantee to Sapphire Energy to help demonstrate an integrated algal biorefinery process in Columbus, NM. For more information on Sapphire and other algae-based biodiesel projects, refer to Section 1.5.4.3 of the RIA.

2008, DOE and USDA awarded $18 million to 18 universities and research institutes to conduct research and development of biomass-based products, biofuels, bioenergy, and related processes.[390] In July 2008, DOE and USDA awarded $10 million to 10 universities and research centers to advance biomass genomics to further the use of cellulosic plant material for bioenergy and biofuels.[391] In August 2008, DOE announced the availability of $7 million to seven DOE National Laboratories to accelerate clean energy technologies, including biofuels.[392] In September 2008, DOE announced plans to invest another $4.4 million in six universities to support research and development for cost-effective, environmentally-friendly biomass conversion technologies for turning non-food feedstocks into advanced biofuels.[393] On October 7, 2008, USDA and DOE released the National Biofuels Action Plan (NBAP), an interagency plan detailing the collaborative efforts of Federal agencies needed to accelerate the development of a sustainable biofuels industry.[394] The plan focuses on seven critical areas including sustainability, feedstock production, feedstock logistics, and conversion technology. On the same day, DOE announced a $7 million investment in five research organizations and institutions to advance technologies needed for stabilization of biomass-based fast pyrolysis oils.[395]

In July 2009, DOE and USDA announced the joint selection of two research centers and five universities to receive $6.3 million towards fundamental genomics-enabled research leading to the improved use of plant feedstocks.[396] In August 2009, DOE announced awards totaling $377 million for 46 Energy Frontier Research Centers.[397] The recipients, funded by the Recovery Act, include at least six centers focused on advanced biofuels (totaling more than $100 million). Later that month, DOE announced that $21 million would be made available to five projects to develop supply systems to handle and deliver high tonnage biomass feedstocks for cellulosic biofuels production.[398] In November 2009, DOE and USDA announced 12 projects selected for over $24 million in grants to research and develop technologies to produce biofuels, Bioenergy, and high-value biobased products.[399]

Numerous states are also offering grants and tax incentives to help encourage biofuel production. Most of the efforts are currently centered on expanding existing production and developing sustainable, second-generation feedstocks, technologies and fuels. According to a recent assessment of DOE’s Energy Efficiency and Renewable Energy (EERE) website, over 20 states currently offer some form of production incentive for advanced biofuels including, but not limited to, those made from cellulosic materials. The incentives range from grants, loan guarantees and tax breaks for advanced biofuel producers to support for technology and feedstock development.

In addition to the production incentives described above, a group of states in the Midwest have joined together to pursue ethanol and other biofuel production and usage goals as part of the Midwest Governors Association (MGA). States that have signed on to the MGA goals include Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, Ohio, South Dakota and Wisconsin. In 2007, the MGA adopted the Midwest Energy Security and Climate Stewardship Platform.[400] The Platform goals are to produce cellulosic ethanol on a commercial level by 2012 and to have E85 offered at one-third of refueling stations by 2025. They also want to reduce the energy intensity of ethanol production and supply 50% of their transportation fuel needs by regionally produced biofuels by 2025. In 2009, the MGA approved a follow-up infrastructure initiative called the Midwestern Energy Infrastructure Accord which includes the governors' support for building out a bio refueling system throughout the region.[401]

The refining industry is also helping to further cellulosic biofuel R&D efforts and fund some of the first commercial plants. Many of the major oil companies have invested in advanced second-generation biofuels over the past 12-18 months. A few refiners (e.g., BP and Shell) have even entered into joint ventures to become cellulosic biofuel producers. General Motors and other vehicle/engine manufacturers are also providing financial support to help with research and development.

A summary of some of the cellulosic biofuel companies with near-term commercialization plans in North America is provided in 1.5-27. The capacities presented represent maximum annual average throughput based on each company's current production plans. However, as noted, capacity does not necessarily translate to production. Actual production of cellulosic biofuel will likely be well below capacity, especially in the early years of production. We will continue to track these companies and the cellulosic biofuel industry as a whole throughout the duration of the RFS2 program. In addition, we will continue to collaborate with EIA in annual standard setting. A more detailed description of the new (commercial demonstration and larger) plants corresponding to these company estimates is provided in Tables 1.5-28 and 1.5-29.

## Table 1.5-27. Potential Growth in Cellulosic Biofuel Capacity by Company and Year*

| | | Capacity Expansion Plans (MGY) | | | | | |
|---|---|---|---|---|---|---|---|
| **Cellulosic Company** | **Biofuel(s)** | **Today** | **Dec-10** | **Dec-11** | **Dec-12** | **Dec-13** | **2014+** |
| Abengoa | Ethanol | 0.02 | 0.02 | 0.02 | 16.02 | 16.02 | 16.02 |
| AE Biofuels | Ethanol | 0.15 | 0.15 | 15.15 | 20.15 | 20.15 | 20.15 |
| BlueFire Ethanol | Ethanol | - | - | - | - | - | 22.90 |
| Cello Energy | Diesel | - | 20.00 | 20.00 | 20.00 | 20.00 | 120.00 |
| CMEC / SunOpta | Ethanol | - | - | - | - | - | 10.00 |
| Coskata | Ethanol | 0.04 | 0.04 | 0.04 | 50.04 | 50.04 | 100.04 |
| Dynamotive[a] | BioOil | 9.00 | 9.00 | 9.00 | 9.00 | 9.00 | 9.00 |
| Enerkem | Ethanol | - | 1.30 | 11.30 | 21.30 | 21.30 | 41.30 |
| Fiberight | Ethanol | - | 2.00 | 6.50 | 6.50 | 6.50 | 6.50 |
| Flambeau River Biofuels | Diesel | - | - | - | 8.00 | 8.00 | 8.00 |
| Fulcrum Bioenergy | Ethanol | - | - | - | 10.50 | 10.50 | 10.50 |
| Inbicon / Great River Energy | Ethanol | - | - | - | - | 20.00 | 20.00 |
| INEOS Bio / New Planet Energy | Ethanol | - | - | 8.00 | 8.00 | 8.00 | 8.00 |
| Iogen | Ethanol | 0.50 | 0.50 | 0.50 | 23.50 | 23.50 | 23.50 |
| KL Energy | Ethanol | 1.50 | 1.50 | 1.50 | 1.50 | 1.50 | 6.50 |
| Mascoma Corporation | Ethanol | 0.20 | 0.20 | 0.20 | 2.20 | 20.20 | 80.20 |
| New Page | Diesel | - | - | - | 2.50 | 2.50 | 2.50 |
| Ohio River Clean Fuels / Baard[b] | Diesel, Naphtha | - | - | - | - | - | 17.00 |
| Pacific Ethanol | Ethanol | - | - | - | - | - | 2.70 |
| POET Biorefining | Ethanol | 0.02 | 0.02 | 25.02 | 25.02 | 25.02 | 25.02 |
| Range Fuels | Methanol, Ethanol | - | 4.00 | 4.00 | 30.00 | 30.00 | 100.00 |
| Rentech[c] | Diesel | - | - | 0.15 | 7.15 | 7.15 | 7.15 |
| Vercipia (Verenium/BP JV) | Ethanol | 1.40 | 1.40 | 1.40 | 37.40 | 37.40 | 37.40 |
| **Maximum Plant Capacity (MGY)** | | **12.83** | **40.13** | **102.78** | **298.78** | **336.78** | **694.38** |

[a] Capacity has been estimated.

[b] Plant will co-process biomass and coal. It is unclear at this time how much fuel would come from biomass and potentially qualify as cellulosic biofuel.

[c] Includes Clearfuels demo plant and Silvagas commercial plant.

*Capacity, not actual production

## Table 1.5-28.
## Promising New Cellulosic Alcohol Plants

| Company/Plant Name | Plant Location | Current Plan | | Production Goal | | Cell. Biofuel | Cell. Tech.[a] | Cell. Feedstocks[b] | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | | Cap (MGY) | Op Date | Cap (MGY) | Op Date | | | AR | EC | W | UW |
| Abengoa Bioenergy Corporation[ac] | Hugoton, KS | 16.00 | 2012 | | | Ethanol | Bio | X | X | | |
| AE Advanced Fuels - Keyes[c,d] | Keyes, CA | 15.00 | 2011 | 20.00 | 2012 | Ethanol | Bio | X | X | | |
| BlueFire Ethanol | Lancaster, CA | | | 3.90 | TBD | Ethanol | Bio | | | X | X |
| BlueFire Ethanol | Fulton, MS | | | 19.00 | TBD | Ethanol | Bio | | | X | |
| Central Minnesota Cellulosic Ethanol Partners[c] | Little Falls, MN | | | 10.00 | TBD | Butanol | Bio | | | X | |
| Coskata / U.S. Sugar Corp. | Clewiston, FL | 50.00 | 2012 | 100.00 | TBD | Ethanol | Thermo | X | | | |
| Enerkem | Pontotoc, MS | 10.00 | 2012 | 20.00 | 2015 | Ethanol | Thermo | | | X | X |
| Enerkem GreenField Alberta Biofuels (EGAB) | Edmonton (CAN) | 10.00 | 2011 | 20.00 | TBD | Ethanol | Thermo | | | | X |
| Fiberight (former Xethanol plant) | Blairstown, IA | 2.00 | End-2010 | 6.50 | 2011 | Ethanol | Bio | | | | X |
| Fulcrum Bioenergy - Sierra BioFuels Plant | McCarran, NV | 10.50 | Mid-2012 | | | Ethanol | Thermo | | | | X |
| Inbicon / Great River Energy | Spiritwood, ND | 20.00 | 2013 | | | Ethanol | Bio | X | | | |
| INEOS Bio / New Planet Bioenergy, LLC | Vero Beach, FL | 8.00 | End-2011 | | | Ethanol | Thermo | X | | | X |
| Iogen Corporation | Prince Albert (CAN) | 23.00 | 2012 | | | Ethanol | Bio | X | | | |
| KL Energy Corp | Kremmling, CO | 5.00 | TBD | | | Ethanol | Bio | | | X | |
| Mascoma Corporation / Frontier Resources | Kinross, MI | 2.00 | 2012 | 20.00 | 2013 | Ethanol | Bio | | | X | |
| Pacific Ethanol | Boardman, OR | 2.70 | TBD | | | Ethanol | Bio | X | | X | |
| POET Project Liberty[c] | Emmetsburg, IA | 25.00 | End-2011 | | | Ethanol | Bio | X | | | |
| Range Fuels[e] | Soperton, GA | 30.00 | 2012 | 100.00 | TBD | Methanol | Thermo | | X | X | |
| Vercipia (Verenium/BP JV) | Highland County, FL | 36.00 | 2012 | | | Ethanol | Bio | | X | | |

[a] Conversion technology. Bio = Biochemical, Thermo = Thermochemical.

[b] Cellulosic feedstocks. AR = Ag residues, EC = Energy crops, W = Wood waste, chips, mill waste, etc., UW = Urban waste including sorted MSW and C&D debris.

[c] Cellulosic ethanol plant will be co-located with an existing corn ethanol plant.

[d] Will start off processing corn and then transition to cellulosic feedstocks.

[e] Will start off producing methanol and then switch catalysts and shift to producing a mix of methanol and ethanol.

## Table 1.5-29
## Promising New Cellulosic Hydrocarbon Plants

| Company/Plant Name | Plant Location | Current Plan | | Production Goal | | Cell. Biofuel | Cell. Tech.[a] | Cell. Feedstocks[b] | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | Cap (MGY) | Op Date | Cap (MGY) | Op Date | | | AR | W | UW |
| Cello Energy | Georgia (TBA) | | | 50.00 | TBD | Diesel | Cat | X | X | |
| Cello Energy | Alabama (TBA) | | | 50.00 | TBD | Diesel | Cat | X | X | |
| Flambeau River Biofuels[c] | Park Falls, WI | 8.00 | 2012 | | | Diesel | Thermo | | X | |
| New Page - Project Independence[c] | Wisconsin Rapids, WI | 2.50 | Early-2012 | | | Diesel | Thermo | | X | |
| Ohio River Clean Fuels, LLC / Baard[d] | Wellsville, OH | 17.00 | 2014 | | | Diesel, Naphtha | Thermo | X | X | |
| Rentech / Rialto Renewable Energy Center | Rialto, CA | 7.00 | End-2012 | | | Diesel | Thermo | | | X |

[a] Conversion technology. Cat = Catalytic depolymerization, Thermo = Thermochemical.

[b] Cellulosic feedstocks. AR = Ag residues, W = Wood waste, chips, mill waste, etc., UW = Urban waste including sorted MSW and C&D debris.

[c] Capacities exclude heavy distillate/wax production.

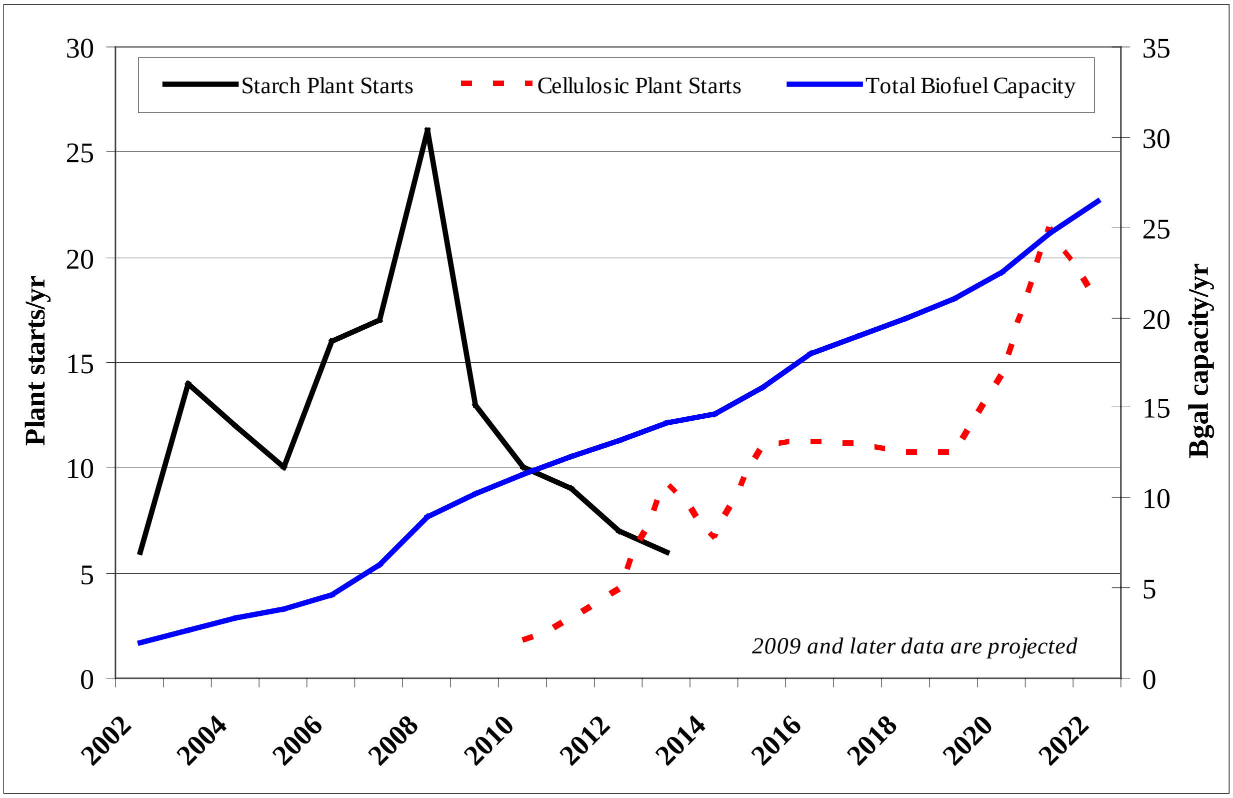
[d] Plant will co-process biomass and coal. It is unclear at this time how much fuel would come from biomass and potentially qualify as cellulosic biofuel.

### 1.5.3.4 Construction Feasibility for Cellulosic Biofuel Industry

Start-up of cellulosic biofuel plants (alcohol or hydrocarbon) is expected to begin in earnest with a few small plants in 2010-11, followed by addition of industry capacity continuing at an increasing pace due to more plant starts per year as well as increasing plant size. This is typical as an industry progresses up the learning curve, and investors become more confident and are willing to fund larger, more efficient plants. During the period from 2010-12, we also expect a slowing of starch ethanol plant construction, such that engineering and construction personnel and equipment fabricators would potentially be able to transition to work on cellulosic biofuel facilities.

Here we examine the build rate required to construct cellulosic plants in time to meet the standards in Table 1.2-1, and we compare this to the historic build rate of capacity in the starch ethanol industry. Figure 1.5-12 depicts these construction trends.

**Figure 1.5-12.**
**Historic and projected plant starts and projection capacity, 2001-2022.[a]**



[a] Volumes do not include biodiesel or renewable diesel.

Historical plant build rates for starch ethanol were derived from capacity information in Figure 1.5-1. Average plant capacity figures were estimated from existing capacity and plant counts, and we project that the recent trend toward larger plant sizes continues going forward. Approximately 200 starch ethanol plants are expected to be operating by 2022.

For cellulosic biofuel plant construction, we assumed new plant size would begin relatively small at 40 million gal/yr for any builds during 2010-13, increasing to 80 million gal/yr for 2014-17, and 100 million gal/yr afterwards. Given the volume standards laid out in the EISA, as well as the volume of cellulosic biofuel projected, we arrive at a maximum required build rate of approximately 2 billion gal/yr from 2018-2022. This is similar to the rate of starch ethanol construction in recent years. Table 1.2-30 shows a summary of the figures used in the analysis.

**Table 1.5-30.**
**Summary of figures used in the cellulosic biofuel plant construction rate analysis, 2001-2022.[a]**

| | Starch Ethanol | | | | Cellulosic Biofuel | | | |
|---|---|---|---|---|---|---|---|---|
| Year | Build Rate [b] *Starts/yr* | Avg Plant Capacity [c] *Mgal/yr* | Capacity Change *Bgal/yr* | Industry Capacity *Bgal/yr* | Build Rate [b] *Starts/yr* | Avg Plant Capacity [c] *Mgal/yr* | Capacity Change *Bgal/yr* | Industry Capacity *Bgal/yr* |
| 2001 | | | | 1.7 | | | | |
| 2002 | 6 | 50 | 0.3 | 2.0 | | | | |
| 2003 | 14 | 50 | 0.7 | 2.7 | | | | |
| 2004 | 12 | 50 | 0.6 | 3.3 | | | | |
| 2005 | 10 | 50 | 0.5 | 3.8 | | | | |
| 2006 | 16 | 50 | 0.8 | 4.6 | | | | |
| 2007 | 17 | 100 | 1.7 | 6.3 | | | | |
| 2008 | 26 | 100 | 2.6 | 8.9 | | | | |
| 2009 | 13 | 100 | 1.3 | 10.2 | | | | |
| 2010 | 10 | 100 | 1.0 | 11.2 | 2 | 40 | 0.1 | 0.1 |
| 2011 | 9 | 100 | 0.9 | 12.1 | 3 | 40 | 0.1 | 0.2 |
| 2012 | 7 | 100 | 0.7 | 12.8 | 4 | 40 | 0.2 | 0.4 |
| 2013 | 6 | 100 | 0.6 | 13.4 | 9 | 40 | 0.4 | 0.7 |
| 2014 | | | | 14.0 | 7 | 80 | 0.5 | 1.3 |
| 2015 | | | | 15.0 | 11 | 80 | 0.9 | 2.1 |
| 2016 | | | | 15.0 | 11 | 80 | 0.9 | 3.0 |
| 2017 | | | | 15.0 | 11 | 80 | 0.9 | 3.9 |
| 2018 | | | | 15.0 | 11 | 100 | 1.1 | 5.0 |
| 2019 | | | | 15.0 | 11 | 100 | 1.1 | 6.1 |
| 2020 | | | | 15.0 | 14 | 100 | 1.4 | 7.5 |
| 2021 | | | | 15.0 | 21 | 100 | 2.1 | 9.7 |
| 2022 | | | | 15.0 | 18 | 100 | 1.8 | 11.4 |

[a] Figures for 2009 and later are projected; volumes do not include biodiesel or renewable diesel. Year-by-year industry capacity figures were taken from RIA Table 1.2-1.
[b] Build rate is an approximate figure, derived from other figures used in this analysis.
[c] Average plant capacity is an approximate figure based on historical ethanol industry trends.

This analysis suggests that it is feasible to construct plants quickly enough to meet the cellulosic standard if plant starts can reach a rate similar to that of starch ethanol plants in recent years. Given that cellulosic biofuel technology is still developing, some types of plants may be considerably more complex and expensive to construct than starch ethanol plants. Therefore, we believe the market will need to react even more enthusiastically with capital funding, design and construction resources.

### 1.5.4 Biodiesel & Renewable Diesel

#### 1.5.4.1 Biodiesel

The biodiesel industry differs significantly in profile from the ethanol industry, in that it is comprised of plants with a wide variety of sizes, ranging from less than one million gallons to more than 50 million gallons per year production capacity, using feedstock ranging from virgin soy oil to recycled cooking grease and rendered fats. The industry capacity has expanded rapidly, going from a sparse network of small businesses selling locally to one with large companies selling internationally in less than a decade. As of November 2009, the aggregate production capacity of biodiesel plants in the U.S. was estimated at 2.8 billion gallons per year across approximately 191 facilities, with a mean size of 16 million gallons per year and a median size of just 6 million gallons per year.[402] Table 1.5-31 shows historical aggregate capacity, sales volumes, and other information related to biodiesel production and use.

**Table 1.5-31. Recent biodiesel industry production and use trends.**[403]

| Year | Domestic production capacity | Domestic total production | Apparent capacity utilization | Net domestic biodiesel use | Net domestic use as percent of production |
|---|---|---|---|---|---|
| 2004 | 245 | 28 | 11% | 27 | 96% |
| 2005 | 395 | 91 | 23% | 91 | 100% |
| 2006 | 792 | 250 | 32% | 261 | 104% |
| 2007 | 1,809 | 490 | 27% | 358 | 73% |
| 2008 | 2,610 | 776 | 30% | 413 | 53% |
| 2009 | 2,806 | 475 (est.) | 17% | 296 (est.) | 62% |

The average capacity utilization had been steady around 30% during 2006-2008 due to continued expansion of on-line capacity despite apparently adequate existing capacity. Reasons for this include various state incentives to build plants, along with state and federal incentives to blend and sell biodiesel, which have given rise to an optimistic industry outlook over the past several years. However, in 2009 utilization was about half this level, due to a steep decline in exports as a result of European trade barriers enacted early in the year, as well as a drop in U.S. diesel prices which has made biodiesel relatively more expensive.

We can speculate that sustained low capacity utilization has been feasible for this industry because of the relatively low capital cost (typically 5-10% of total per-gallon production cost) of these plants, which enables them to operate only part of the year or at reduced capacity, depending on feedstock prices or other market conditions. Besides fuel, some plants may also produce oleochemicals for use in detergents, lubricants or other products, providing additional sources of revenue for part of the industry.

In order to conduct our emissions and distribution analyses, we needed to have an industry characterization at the time of the fully phased-in program, the year 2022. This was not a simple task because of the apparent feasibility of sustained over-capacity and the variety of useable feedstocks. As discussed in Section 1.2, we project under our primary control case that in order to meet the RFS2 standards, 1.67 billion gallons of biodiesel will be produced in 2022. With this information, we estimated how many plants would continue to produce biodiesel and where they might be located based on three factors: state incentives for production and sales, BQ-9000 certification of existing plants, and capabilities for handling multiple feedstock types. This information was gathered from a database of member plants maintained by the National Biodiesel Board, and a summary of tax incentives from the Department of Energy website. [404] Existing plants with affirmative status for more of these factors were expected to be more likely to survive over those that had fewer. We also projected that a number of very small plants processing waste greases/fats would continue to operate based on local market niches regardless of these criteria.

We project that between now and 2022 the number of plants will decline by about 30%, pushing capacity utilization above 80%. It is expected that plants will continue to operate in 44 states. During this period most plants will have added the pre-treatment and feedstock segregation capacity to process any mix of feedstock types available in their area. Multi-product plants will retain the capacity to produce biodiesel, but it is not expected to be their primary product due to higher margins for more specialized products like surfactants, lubricants, or renewable oleochemical feedstocks for re-sale. Table 1.5-32 summarizes key parameters of the industry as it is currently and in the 2022 forecast.

**Table 1.5-32. Summary of Current Biodiesel Industry and Forecast.**[405]

| | 2008 | 2022 |
|---|---|---|
| Total production capacity on-line (million gal/yr) | 2,610 | 1,968 |
| Number of operating plants | 176 | 121 |
| Median plant size (million gal/yr) | 5 | 5 |
| Total biodiesel production (million gal) | 776 | 1,670 |
| Average plant utilization | 0.30 | 0.85 |

### 1.5.4.2 Renewable Diesel

For a period of time in 2007 and 2008, ConocoPhilips produced small quantities (300-500 bbl/day) of renewable diesel at their Borger, Texas, refinery from beef tallow generated by Tyson Foods, Inc. in Amarillo, Texas. This operation was stopped primarily due to changes in tax law that reduced the subsidy for renewable diesel products being coprocessed with petroleum at refineries. [406]

In fall of 2008, Dynamic Fuels, LLC (a joint venture of Syntroleum Corp. and Tyson Foods, Inc.) announced construction of a 75 million gallon per year plant (5,000 bbl/day) in Geismar, Louisiana, that will use Tyson meat processing byproducts as feedstock to Syntroleum’s Bio-Synfining process. Start-up is scheduled for 2010, with the primary product being high-quality diesel fuel that will be fungible within the existing petroleum supply system.[407] The Geismar facility plans to utilize supplies of hydrogen available in the industrial park where it will be located, as well as rail and shipping infrastructure already in place nearby.[408] However, it is not co-located with existing petroleum production, and therefore would be considered a stand-alone facility in our analyses (thus meeting the definition of non-coprocessed fuel eligible to generate RINs counting toward the biomass-based diesel standard).

Our industry projection is based on the expectation of that Dynamic Fuels, LLC, (or another company) will construct and operate two facilities like the one underway in Geismar, LA, during our analysis period.[409] It is conceivable that more facilities will be built by Dynamic Fuels or other companies (such as Neste), or that some renewable diesel will be imported into the U.S., but we felt there was too much uncertainty to project volumes, given the large capacity for biodiesel production already on-line. Also, considering tax subsidy and RIN incentives putting co-processed renewable diesel at a disadvantage, we've chosen to assume all renewable diesel is produced in stand-alone facilities.

### 1.5.4.3 Algae-Based Biofuel

Recently, there has been a renewed interest in the production of algae-based biofuels and a growth in the number of potential technology providers. To give a sense of the size of the industry, we've developed a list of over 70 companies from various locations around the world and summarized a basic description of their technologies for algae production (Table 1.5-33). This list is current as of November 2009 and is based mainly on biofuel magazines and articles that are supplemented with company websites. As new information is available on a near daily basis, it is possible that we have not included newly formed companies or those not highly publicized.

Companies that have announced plans for algae-based biofuel production include: Sapphire Energy for 135 MMgal by 2018 and 1 Bgal by 2025, Petrosun for a 30 MMgal/yr facility, Solazyme for 100 MMgal by 2012/13, and U.S. Biofuels for 4 MMgal by 2010 and 50 MMgal by full scale. It is important to realize that future projections are highly uncertain, and we have taken into account the best information we could acquire at the time. For more information on algae as a feedstock for biofuel, refer to Section 1.1.3.4.

In recent months, there have also been grants given to technologies based on algae. On December 4, 2009, the Department of Energy announced that it awarded several algae-based technology providers. This included the following companies: Algenol Biofuels ($25 million grant for a pilot scale project located in Freeport, Texas), Solazyme ($22 million grant for a pilot scale project located in Riverside, Pennsylvania) and Sapphire Energy ($50 million grant for a demonstration scale project located in Columbus, New Mexico).

### Table 1.5-33. Companies Developing Algae Production Technologies[PPP]

| Company Name | Technology | Headquarters & Facilities |
|---|---|---|
| A2BE Carbon Capture | Closed PBR algae system recycling CO2 from industries. | Boulder, Colorado |
| Advanced Lab Group | Polyethylene film for closed PBRs, wants to reduce costs for harvesting and dewatering, heat venting for closed systems, and reduce oil extraction and process costs. | Santa Monica, California |
| Alfa Laval | Algae/water separability tests using different centrifuge test units. | Headquarters in Sweden |
| Algae Venture Systems | Develops harvesting, dewatering, and drying of algae technology. | Marysville, Ohio |
| AlgaeLink | Uses photobioreactor (PBR) technology and has expertise in extracting oil and biomass. Offers algae production capacity for a farm of 250 ton dry algae per day. | Dutch-based, plant in the Netherlands |
| Algenol Biofuels | Direct to ethanol process, using algae, sunlight, CO2, and seawater. Produces ethanol at rate of 6,000 gallons per acre per year, targeting 10,000 gallons per acre per year. Ethanol is produced inside each algae cell. Uses hybrid algae in sealed, clear plastic photobioreactors. | Plans first US plant in Florida or Texas. One in development in Sonora, Mexico with company called BioFields. Corporate headquarters in Naples, Florida. Goal is to have 4 sites in US by 2010, target Florida, Texas, Arizona, New Mexico. Announced on June 29, 2009, demo plans of 3,100 bioreactors on a 24-acre site at Dow's Freeport, Texas site. |
| Aquaflow Bionomic Corporation | Produce biofuel from wild algae harvested from open air environments, clean-up algae-infested polluted water systems. | New Zealand |
| Aquatic Energy | Proprietary strain of algae for continuous outdoor growth, filed patents for growth and harvesting techniques. Interested in developing, constructing, and operating open pond algae farms. | Headquarters in Lake Charles, Louisiana; Couple of acre pilot facility in Lake Charles |

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[PPP] Although we provide this summary here, we caveat that we have not confirmed the statements made on the company websites or on the data collected from news magazine/articles. For latest information please refer to the company's website or contact the company's representatives. Blanks occur where information was not available or found.

| | | |
|---|---|---|
| Aurora Biofuels | Use genetically-modified algae to generate oil for production of biodiesel. Uses seawater-fed, open ponds. Has produced slightly under 1,000 gallons oil per year from 1/8th acre surface area. The company estimates that will translate into 6,000 gallons/yr/acre at commercial size. The company uses waste water technology and a wet extraction process instead of the traditional process of centrifugation and drying. On August 18, 2009 announced that it had optimized particular algae strains to more than double their uptake of carbon dioxide. | Headquarters in Alameda, California ;Developed at the University of California at Berkeley; Pilot-Scale facility in Florida |
| AXI LLC | Developing various strains of algae for the production of biofuels. | Quincy, Massachusetts |
| BARD, LLC | BARD's closed loop photo-bioreactor technology can produce 66 million gallon of algae oil in 7 acres of land, which is 8,571,428 gallon of algae oil per acre. The pilot facility will begin by producing 43,070 gallons of algae oil / biodiesel per annum using only six modules of photo-bioreactors covering 84 square feet. | Commercial scale algae system pilot facility located in the Commonwealth of Pennsylvania also plans for plant in Ohio. |
| Bellona | Supports algae in photobioreactors which can deliver food, fodder and fuel. | Norway |
| Bio Algene | Use algae to generate oil for production of biodiesel and extract oil by breaking cell wall. Algae cultivation to remediate pollution, produce fuel and other bioproducts. Company has developed methods to accelerate algae growth and is investigating different harvesting methods. | Headquarters near Seattle |
| Biocentric Energy | Manufactures and sells closed loop algae bioreactor systems for commercialization. | California |
| Biofuel Systems Group Limited | Use phytoplankton to produce biodiesel. Design and build biodiesel processing systems. | England |

| | | |
|---|---|---|
| Biolight Harvesting | Develop renewable fuels and chemicals from blue-green algae. Biolight is focused on brackish water and agricultural runoff as a long-term medium for cultivation. | California; 40-acre pilot facility in California's Imperial Valley |
| Bionavitas | High-volume production of algae using biofactories and fiber-optic lights in algaculture system. Claims to have a cost-efficient way to deliver light to biomass. Light Immersion Technology (LIT). | Redmond, Washington |
| BioProcess Algae LLC | Photobioreactor systems coupled next to an ethanol facility which provides water, heat, and CO2. | Pilot project anticipated to be in Shenandoah, Iowa |
| Blue Marble Energy | Convert algal biomass to energy by creating, centralizing, and harvesting wild algae blooms. BME’s proprietary AGATE (Acid, Gas, and Ammonia Targeted Extraction) system processes nearly any organic feedstock, utilizing cultured strains of bacteria to perform fermentation (like brewing beer) to produce a wide variety of biochemicals; can utilize wet biomass, bypassing energy-intensive drying | Seattle, Washington |
| Bodega Algae LLC | Developer of scalable algae photobioreactors. Developing proprietary light technology to enhance growth of algae. | Headquarters in Boston, Massachusetts |
| Canadian Pacific Algae Inc. | Grower and producer of phytoplankton (marine microalgae), current research center uses eight - 1 million liter tanks. | Nanaimo, British Columbia |
| Carbon Capture Corp. | Operates open algae ponds. In the business of processing algal-derived renewable diesel, butanol, biomethane and jet fuel propellant. | La Jolla, California; 40-acre Algae Research Center, part of a 326-acre R&D facility in Imperial Valley, California |
| Cellena | Open pond and PBR technology. Developing process for extracting algae oil without chemical use, drying or an oil press. Kona facility will grow only non-modified, marine microalgae in a hybrid system. | Hawaii; Building an open-pond demo facility in Hawaii - Kona Pilot Facility on Big Island began on January 16, 2008. |

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| Circle Biodiesel and Ethanol Corporation | Have manufactured an algae photobioreactor for the production of algae. Also has an algae harvesting system for the extraction of algae oil for algae biodiesel or algae biofuel. Algae harvesting system retails for $195,000 US dollars, can process one gallon of algae oil per minute. | Headquarters in San Marcos, California |
| Desert Sweet Biofuels | Using a combination of gasification and pyrolysis in such a way as to produce biochar, a byproduct is electricity. One low cost algae production system currently being developed is vectoring algae through Daphnia. | Gila Bend, Arizona |
| Diversified Energy Corp. | Has licensed technology from XL Renewables under the name Simgae for simple algae. | Gilbert, Arizona |
| Dynamic Biogenics | Utilizes photobioreactors. | Headquarters in Sacramento, California |
| ENN | | Hebei Province, China |
| General Atomics | Developing improved processes for growing and extracting oil from algae in open ponds. | San Diego, California |
| Genifuel | Licensed method to convert algae into renewable natural gas. Uses wet biomass like algae in a gasifier - Catalytic Hydrothermal Gasifier (CHG). The gasifier was developed by PNNL. Focus on outdoor ponds or inexpensive troughs. | |
| Global Green Solutions Inc. | Focused initially on biodiesel feedstock. Developed Vertigro, self-contained algae growing system. | Vancouver, British Colombia |
| Green Plains | Fourth largest ethanol producer in North America. Focus on photobioreactor systems. The pilot plant is planned to be used for animal feed, at least initially. | Shenandoah, Iowa; pilot project expected to be operational by July 2009 |
| Green Star Products | Developed formulas to increase algae growth rates, Montana Micronutrient Booster (MMB). Developed wet-algae stripping technology. | Headquarters in San Diego, California. Had plans to move algae facility to Utah. |

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| GreenShift | Has license agreement with Ohio University for bioreactor. | Corporate offices in New York, New York; Engineering located in Alpharetta, Georgia |
| HeroBX (formerly Lake Erie Biofuels) | Investigating algae as a feedstock, conducting a vetting process with PBRs. | Erie, Pennsylvania |
| HR Biopetroleum Inc. | Focus on earth-marine microalgae plants to produce biofuel feedstocks and animal nutrition products. The company offers algae products, such as algae oil, biodiesel, and animal feed proteins; carbohydrates for the production of ethanol and petroleum-based products; and military jet fuel. The technology is focused on coupling PBRs with open pond systems. | Hawaii |
| Infinifuel Biodiesel | Focusing on algae for biodiesel using algae ponds. | Headquarters in Dayton, Nevada |
| Ingrepro | Focused on open-pond systems. Suggests that best business model will remediate waters, integrate heat, and produce multiple products. | Netherlands; Plans to build algae facilities in Malaysia |
| International Energy Inc. | PBR | Washington, DC |
| Inventure Chemical Technology | Patent-pending algae-to-jet fuel product. The company provides expertise in both process conversion and plant design and construction. | Gig Harbor, Washington |
| Kai BioEnergy | Continuous, open pond system that produces bio crude oil from microalgae. Technology claims to overcome risk of algae contamination and allows for high yield growth of a dominant species. | Del Mar, California and Hawaii |
| Kelco | Harvests natural kelp beds. | San Diego, California |
| Kent BioEnergy | Develops open pond algae farm, experience in aquaculture. | San Diego, California; 160-acre process development/production facility south of Palm Springs |
| Live Fuels Inc. | Open-pond algae bioreactors to create green crude, not ethanol or biodiesel. Up to 20,000 gallons per acre predicted for algae yield. The | Headquarters in Menlo Park, California; Original plans to grow algae in ponds at the Salton Sea, an inland saline lake in |

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| | company grows a mix of native algae species in 45 acres of open saltwater ponds. To harvest the algae, the company uses “algae grazers” such as filter-feeding fish species and other aquatic herbivores. The fish, including those from the Tilapia or sardine families, collect and clean the algae through structures in their mouths, according to the company. They swallow it and the algae is digested and concentrated in the fish’s flesh. To extract the oil, the fish are cooked and pressure is applied, resulting in Omega-3 fatty acids and other oils used as feedstocks for renewable fuels. | Southern California, but has shifted to Texas. Will begin pilot operations at its test facility in Brownsville, Texas. The results of the pilot project will be used to commercialize the process along the coast of Louisiana. |
| Martek Biosciences Corporation | Martek currently produces algae in a closed, dark system where the algae are fed sugars in a fermentation process similar to yeast growing on corn sugar, in contrast to the photosynthetic processes being developed by others in the algae-to-fuel race. The sugar-to-biodiesel pathway will use advanced biological science to convert sugars derived from biomass into lipids which are then converted into fuel molecules through chemical or thermocatalytic processes. | Maryland |
| MBD Energy | Algae grown in waste water with high concentration of CO2 from a nearby power plant. Algae are harvested to produce algae oil and algae meal. | East Melbourne, Australia |
| Neptune Industries | Has a patented system to use fish waste for the growth of algae for biofuels and methane gas. | Boca Raton, Florida |
| Odyssey Oil and Energy Inc. | Company focuses on carbon sequestration and generation of renewable energy. PBR technology, ALG Bio Oil Ltd. | Pretoria, South Africa |

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| OriginOil | The company's bioreactor attempts to speed the growth of algae in a tank by blending light emitted from a rotating shaft with nutrients. The process does not require chemicals, initial dewatering, or high capex for heavy machinery. The company's technology combines electromagnetism and pH modification to break down cell walls, releasing algal oil within the cells. The oil rises to the top for skimming and refining, while the remaining biomass settles to the bottom for further processing as fuel and other valuable products. | Los Angeles, California |
| Petroalgae | Developing a commercialized system of technologies to grow and harvest oil from algae. Certain initial alga strains originated at the National Renewable Energy Lab ("NREL"). Selected and utilizes strains of algae to optimize growth and harvest characteristics for different applications and different geographic environments. | Based in Melbourne, FL; Pilot plant in Fellsmere; Plans to complete a 20-acre demo algae farm by end of 2009. |
| PetroSun | | Scottsdale, Arizona, factory in Rio Honda, Texas |
| Phycal | Aims to harvest oil from algae without killing it, by bathing in solvents that remove the oil. Olexal non-destructive extraction "milking" process. | Highland Heights, Ohio; Pilot by end of 2009. Sub-pilot scale in Ohio and R&D lab in St. Louis. Pilot facility in Hawaii planned to begin operations in 2010. |
| Plankton Power | Closed ponds and integrated PBR, continuous process with low energy algal separation, oil extraction. | Wellfeet, Massachusetts |
| Primafuel | Grown in shallow ponds with sunlight and fertilizers as inputs; Fertilizers are grass clippings and wood biomass. | Signal Hill, CA<br>Lund, Sweden |
| Renewed World Energies | Reportedly, the only fully automated and modular photo-bioreactor currently available, yields algae oil and cake. Captures nitrogen oxides and CO2 from flue | Georgetown, South Carolina |

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| | gases. | |
| SAIC | Focus on creation of algae-based jet fuel | Headquarters in McLean, Virginia; locations in 150 cities worldwide |
| Sapphire Energy | Plans to grow algae in open ponds of unusable water. Algae-based based fuels developed include gasoline, diesel, and aviation fuels. | San Diego, California; Demo in Las Cruces, California |
| SCIPIO Biofuels | Continuously circulating photobioreactors and continuous algae harvester. The company says it will target whatever fuel is demanded, be it jet fuel, ethanol, biodiesel, or biobutanol. | Headquarters in Laguna Hills, California<br>Plans for facility in Greensburg, Kansas |
| Seambiotic | Produces marine algae for a variety of applications, health foods, chemicals, medical products, and biofuels. Uses raceway/paddle-wheel open-pond algae cultivation. | Ashkelon, Israel |
| Solazyme | Grows algae in the dark using standard industrial bioproduction equipment, where the algae are fed a variety of non-food and waste biomass materials including cellulosic biomass and low-grade glycerol. | Headquarters in San Francisco, California |
| Solena Group | Plasma technology to gasify algae and other organics into energy outputs. Algae would be grown in big plastic containers and fed sunlight and sodium bicarbonate. Biomass is converted to syngas to produce electricity. | Headquarters in Washington D.C.; European Office in Madrid, Spain |
| Solix Biofuels | Harvest oil, uses PBR; After oil is extracted the rest can be used as animal feed and ethanol. Claims to use less water than other processes. | Headquarters in Fort Collins, Colorado. Announced in 2008 that it will build its first large scale facility at nearby New Belgian Brewery, where CO2 produced will be used to feed the algae. Plans for a Coyote Gulch Demonstration Facility, which will be operational by late summer 2009. The Utes chipped in more than $20 million and the land |

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| | | for the project in Southwest Colorado. |
| StellarWind Bioenergy | The company is using its proprietary PhycoGenic Reactor and PhycoProcessor systems as well as a RecyCO2Tron system for CO2 recovery. The PhycoProcessor is an oil recovery system. Their resource recovery system coverts algae biomass into methane, charcoal, fertilizer, or syngas. | Indianapolis, Indiana |
| SunEco Energy | Harvesting and growth of native algae species in open ponds, claims to can produce at least 33,000 gallons of biocrude per acre-foot per year. | Headquarters in Chino, California; Operations in Niland, California |
| Synthetic Genomics | Synthetic is collaborating with Exxon Mobil to research and develop the most advanced algae. In the future hope to mass farm the oil from algae. | La Jolla, California |
| Texas Clean Fuels | Developing photobioreactors and equipment for algae farms. Their product line, known as MOPS (Micro Organism Production System) | Headquarters in Rockwall, Texas |
| Univenture | Algae harvesting system that could reduce energy cost due to harvesting, dewatering, and drying of algae using a novel absorbent moving belt harvester. | Operations in Ohio, Ireland, China |
| US Biofuels | PBR | Negotiating with Co-op Greenhouse regarding locations in Fresno, the Imperial Valley, and Palmdale. |
| Valcent Products Inc. | Creates, designs, and develops patents e.g. vertical bioreactors in a closed loop. | Headquarters in El Paso, Texas |
| Vertigro Energy | Closed-loop vertical algae growth system. | San Diego, California; commercial-scale bioreactor pilot project in El Paso, Texas |

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| W2 Energy Inc. | SunFilter technology: a tubular algae bioreactor; Inside the bioreactor, low-power ultraviolet lights, in combination with the gases, feed the algae so it grows and fills the tubes with blooms. When the blooms have reached an appropriate density, a set of magnetic rings inside the tubes scrapes the blooms clean and pushes the algae to the upper manifold, where compressed air pushes it out. The algae is then compressed, dried and then either gasified or fed into a biodiesel reactor to produce biodiesel. W2 also has developed a multi-fuel reactor to produce ultra-low sulfur diesel, a blend of JP8 jet fuel or gasoline; a plasma-assisted gasifier; a SteamRay rotary system engine that converts energy from steam or fuel combustion into a rotary force; small energy generating systems; and the Non-Thermal Plasmatron. | Carson City, NV; Plans for bioreactor running in Guelph, Ontario in mid-Sept 2009 |
| XL Renewables (formerly XL Dairy Group) | Patent-pending hybrid algae system that can operate as a closed or open system. Focuses on creating renewable energy using dairy waste streams. Wants to produce algae biomass for animal feeds (high omega-oil content). Their Super Trough System design is expected to provide annual algae yield of 300 dry tons/acre. | Phoenix, Arizona; Developing a 400-acre integrated biorefinery located in Vicksburg, Arizona. Algae Development Center in Cas Grande, Arizona. |

## 1.6 Biofuel Distribution

### 1.6.1 Biofuel Distribution Overview

The current motor fuel distribution infrastructure has been optimized to facilitate the movement of petroleum-based fuels. Consequently, there are very efficient pipeline-terminal networks that move large volumes of petroleum-based fuels from production/import centers on the Gulf Coast and the Northeast into the heartland of the country. In contrast, the most biofuel volumes are produced in the heartland of the country and need to be shipped to the coasts, flowing roughly in the opposite direction of petroleum-based fuels. The location of renewable fuel production plants is often dictated by the need to be close to the source of the feedstocks used rather than to fuel demand centers or to take advantage of the existing pipeline distribution system for petroleum products.[QQQ]

To varying degrees, the physical/chemical nature of some biofuels also limit the extent to which they can be shipped/stored fungibly with petroleum-based fuels. The vast majority of biofuels are currently shipped by rail, barge and tank truck to petroleum terminals. All biofuels currently are blended with petroleum-based fuels prior to use. Most biofuel blends can be used in conventional vehicles. However, E85 can only be used in flex-fuel vehicles, requires specially-constructed retail dispensing/storage equipment, and may require special blendstocks at terminals. These factors limit the ability of biofuels to utilize the existing petroleum fuel distribution infrastructure. Hence, the distribution of renewable fuels raises unique concerns and in many instances requires the addition of new transportation, storage, blending, and retail equipment.

Significant challenges must be faced in reconfiguring the distribution system to accommodate the large volumes of biofuels that we project would be used to meet the proposed standards. Considerable efforts are underway by individual companies in the fuel distribution system, consortiums of such companies, industry associations, independent study groups, and inter-agency governmental organizations to evaluate what steps might be necessary to facilitate the necessary upgrades to the distribution system to support compliance with the volumes of biofuels required by the RFS2 standards.[RRR] EPA will continue to participate in or monitor these efforts as appropriate.

Considerations related to the distribution of ethanol, cellulosic distillate fuel, renewable diesel fuel, and biodiesel are discussed in the following sections as well as the changes to each segment in the distribution system that would be needed to support the volumes that we project would be used to satisfy the RFS2 standards. The costs associated with making the necessary changes to the fuel distribution infrastructure are discussed in Section 4.2 of this RIA. The importation of ethanol into the U.S. is discussed in Section 1.5.2 of this RIA.

### 1.6.2 Biofuel Shipment to Petroleum Terminals

Pipelines are the preferred method of shipping large volumes of petroleum products over long distances because of the relative low cost and reliability. Ethanol currently is not commonly shipped by pipeline because it can cause stress corrosion cracking in pipeline walls and its affinity for water and solvency can result in product contamination concerns.[410] Shipping ethanol in pipelines that carry distillate fuels as well as gasoline also presents unique difficulties in coping with the volumes of a distillate-ethanol mixture which would typically result.[SSS] We

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[QQQ] A discussion of the projected locations of ethanol production facilities can be found in Chapter 1.5 of this RIA.

[RRR] For example, the "Biomass Research and Development Board", an inter-governmental group co-chaired by USDA and DOE., includes a group that is focused on evaluating biofuels distribution infrastructure issues. http://www.usbiomassboard.gov/distribution_infrastructure.htm

[SSS] Different grades of gasoline and diesel fuel are typically shipped in multi-product pipelines in batches that abut each other. To the extent possible, products are sequenced in a way to allow the interface mixture between batches believe that it is currently not possible to re-process this mixture in the way that diesel-gasoline mixtures resulting from pipeline shipment are currently handled.[TTT] The Pipeline Research Council International (PRCI) in coordination with the Pipeline and Hazardous Materials Safety Administration (PHMSA), and the Association of Oil Pipelines (AOPL) are conducting research to address the safety and technical challenges to pipeline transportation of ethanol.[411] A short gasoline pipeline in Florida is currently shipping batches of ethanol and other more extensive pipeline systems have feasibility studies underway.[412] Thus, existing petroleum pipelines in some areas of the country may play an increasing role in the shipment of ethanol. Evaluations are also currently underway regarding the feasibility of constructing a new dedicated ethanol pipeline from the Midwest to the East coast.[413] Substantial issues would need to be addressed before construction on such a pipeline could proceed, including those associated with securing new rights-of-ways and establishing sufficient surety regarding the return on the several billion dollar investment.

We expect that cellulosic distillate fuels and renewable diesel fuel will not have materials compatibility issues with the existing petroleum fuel distribution infrastructure. Thus, there may be more opportunity for these biofuels to be shipped by pipeline. However, the location of ethanol and cellulosic distillate/renewable diesel production facilities relative to the origination points for existing petroleum pipelines will be a limiting factor regarding the extent to which pipelines can be used. The gathering of ethanol from production facilities located in the Midwest and shipment by barge down the Mississippi for introduction to pipelines in the Gulf Coast has been discussed by industry. This approach might also be considered for cellulosic distillate fuel when such plants are constructed. However, the additional handling steps to bring the ethanol or cellulosic distillate fuel to the pipeline origin points in this manner could negate the potential benefit of shipment by existing petroleum pipelines compared to direct shipment by rail.

Biodiesel is currently not widely shipped by pipeline due to concerns that it may contaminate jet fuel that is shipped on the same pipeline and potential incompatibility with pipeline gaskets and seals. Segments of Kinder Morgan's Plantation pipeline are currently shipping B5 blends, and its Oregon Pipeline that runs from Portland to Eugene is currently shipping B2 blends.[414] These systems do not handle jet fuel. The shipment of biodiesel by pipeline may become more widespread and might be expanded to systems that handle jet fuel. However, the relatively small production volumes from individual biodiesel plants and the widespread location of such production facilities may tend to limit the extent to which biodiesel may be shipped by pipeline. Rail cars, barges, and tank trucks that transport biodiesel over long distances will need to be heated/insulated in cold climates to prevent gelling.

Due to the uncertainties regarding the extent to which pipelines might participate in the transportation of biofuels in the future, we assumed that biofuels will continue to be transported by rail, barge, and truck to petroleum terminals as the vast majority of biofuel volumes are today.

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to be cut into one of the adjoining products. In cases where diesel fuel abuts gasoline in the pipeline, the resulting mixture must typically be reprocessed into its component parts by distillation for resale as gasoline and diesel fuel.

[TTT] We believe that it is not currently possible to separate ethanol from a gasoline/diesel mixture sufficiently by distillation. Hence, a significant amount of ethanol may remain in the gasoline and diesel fractions separated by distillation. Gasoline-ethanol mixtures can be blended into finished gasoline provided the applicable maximum allowed ethanol concentration is not exceeded. However, diesel-ethanol mixtures can not be used as motor fuel.

To the extent that pipelines do play an increasing role in the distribution of ethanol, this may improve reliability in supply and reduce distribution costs.

Apart from increased shipment by pipeline, biofuel distribution, and in particular ethanol distribution, can be further optimized primarily through the expanded use of unit trains. Unit trains are composed entirely of 70-100 ethanol tank cars, and are dedicated to shuttle back and forth to large hub terminals. In the future, unit trains might also be used for the shipment of cellulosic distillate fuel. Unit trains can be assembled at a single production plant or if a group of plants are not large enough to support such service individually, can be formed at a central facility which gathers fuel from a number of producers. The Manly Terminal in Iowa, accepts ethanol from a number of nearby smaller ethanol production facilities for shipment by unit train. Regional (Class 2) railroad companies are an important link bringing ethanol to gathering facilities for assembly into unit trains for long-distance shipment by larger (Class 1) railroads. We anticipate that the vast majority of new ethanol and cellulosic distillate facilities will be sized to facilitate unit train service. We do not expect that biodiesel facilities will be of sufficient size to justify shipment by unit train. In the NPRM, we projected that unit train receipt facilities would be located at petroleum terminals and existing rail terminals. Based on industry input regarding the logistical hurdles in citing unit train receipt facilities at petroleum/existing rail terminals, we expect that such facilities will be constructed on dedicated property with rail access that is as close to petroleum terminals as practicable.[UUU]

Shipment of biofuels by manifest rail to existing rail terminals will continue to be an important means of supplying biofuels to distant markets where the volume of the production facility and/or the local demand is not sufficient to justify shipment by unit train. Manifest rail shipment refers to the shipment of biofuel in rail tanks cars that are incorporated into trains which are composed of a variety of other commodities. Shipments by barge will also play an important role in those instances where production and demand centers have water access and in some cases as the final link from a unit train receipt facility to a petroleum terminal. Direct shipment by tank truck from production facilities to petroleum terminals will also continue for shipment over distances shorter than 200 miles.

We project that most biofuel volumes shipped by rail will be delivered to petroleum terminals by tank truck.[VVV] We expect that this will always be the case for manifest rail shipments. In the NPRM we projected that trans-loading of biofuels from rail cars to tank trucks would be an interim measure until biofuel storage tanks were constructed.[WWW] Based on industry input, we now expect trans-loading will be a long-term means of transferring manifest rail car shipments of biofuels received at existing rail terminals to tank trucks for delivery to petroleum terminals. We also anticipate that trans-loading will be used at some unit train receipt facilities, although we expect that most of these facilities will install biofuel storage tanks from which tank trucks will be filled for delivery to petroleum terminals. Imported biofuels will

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[UUU] Existing unit train receipt facilities have primarily followed this model. See the US Development Group's interactive map of their ethanol unit train receipt facilities at http://www.us-dev.com/terminals.htm

[VVV] At least one current ethanol unit train receipt facility has a pipeline link to a nearby terminal. To the extent that additional unit train receipt facilities could accomplish the final link to petroleum terminals by pipeline, this would significantly reduce the need for shipment by tank truck.

[WWW] Trans-loading refers to the direct transfer of the contents of a rail car to a tank truck without the intervening delivery into a storage tank.

typically be received and be further distributed by tank truck from petroleum terminals that already have receipt facilities for waterborne fuel shipments.

Our analysis of the shipment of ethanol and cellulosic distillate fuels to petroleum terminals is based on the Oakridge National Laboratory (ORNL) analysis of ethanol transportation activity under the EISA that was conducted for EPA.[415] The ORNL analysis contains detailed projections of which transportation modes and combination of modes (e.g. unit train to barge) are best suited for delivery of ethanol to specific markets considering ethanol source and end use locations, the current configuration and projected evolution of the distribution system, and cost considerations for the different transportation modes. The NPRM analysis assumed that all biofuel volumes other than biodiesel would be ethanol. For this FRM, we analyzed three scenarios under which varying volumes of cellulosic distillate fuel would take the place of ethanol production volumes to satisfy the RFS2 requirements. However, due to the timing of the various analyses for the FRM, the NPRM projections of the location of ethanol production facilities and end use areas contained in the NPRM had to be used as the inputs into the ORNL analysis. Our use of the ORNL analysis to evaluate the distribution impacts for the final rule assumes that cellulosic distillate production plants would take the place of some of the ethanol production plants projected in the NPRM. It further assumes that cellulosic distillate fuel use would coincide with the ethanol end-use areas projected in the NPRM.

The extent to which new cellulosic distillate fuel and cellulosic ethanol production facilities are more dispersed than projected in the NPRM, distribution for ethanol from new production facilities and from all cellulosic distillate facilities might be simplified as the fuel has more opportunity to be used locally. Cellulosic distillate fuel distribution may also be further simplified to the extent that in the future it is blended with petroleum-based diesel fuel in higher blend-ratios than the 20% blends currently registered by EPA. An increased blend ratio for cellulosic distillate fuel would tend to enhance the ability for its use close to the place of manufacture rather than having to be spread more widely over a larger petroleum diesel pool.

We projected the volumes of biodiesel that would be used on a State-by-State basis to meet anticipated State biodiesel mandates/incentives and the estimated demand for biodiesel as a blending component in heating oil. Using the estimated locations of biodiesel production facilities and their volumes, we evaluated the most efficient means of meeting this projected demand while minimizing shipping distances (and cost). The remaining biodiesel production volume from these production facilities that was needed to meet the RFS2 mandated volume was assumed to be used in the same State where it was produced up to the point where the State’s entire diesel fuel pool contained 5% biodiesel. We believe that this should provide a somewhat conservatively high estimate of biodiesel distribution costs since biodiesel might be used in excess of 5% even absent a State mandate. If a State was already saturated with 5% biodiesel, the remaining volume was assumed to be shipped out of State within a 1,000 mile shipping distance. A 1,000 mile shipping distance was selected to ensure that all biodiesel not used to satisfy a State mandate or for bio-heat could find a market. It is likely that some fraction would not need to travel quite as far. Therefore, this assumption is also likely to result in a conservatively high estimate of biodiesel freight costs. It was assumed that biodiesel production volumes will continue to be insufficiently concentrated to justify shipment by unit train. Where distances are beyond 300 miles, shipment by manifest rail was assumed to be the preferred option other than in cases on the East coast where there were apparent barge routes from production to demand centers. In case where biodiesel is shipped by manifest rail, it was assumed that it would be trans-loaded at a rail terminal for further shipment by tank truck to a petroleum terminal. Additional discussion of our estimate of how increased biodiesel volumes used to comply with the RFS2 standards would be transported to petroleum terminals can be found in Section 4.2 of this RIA on biodiesel freight costs.

We anticipate that the deployment of the necessary distribution infrastructure to accommodate the shipment of biofuels to petroleum terminals is achievable. We believe that construction of the requisite rail cars, barges, tank trucks, tank truck and rail/barge/truck receipt facilities is within the reach of the corresponding construction firms. Although shipment of biofuels by rail represents a major fraction of all biofuel ton-miles, it is projected to account for approximately 0.4% of all rail freight by 2022.[XXX] Many improvements to the freight rail system will be required in the next 15 years to keep pace with the large increase in the overall freight demand. Given the broad importance to the U.S. economy of meeting the anticipated increase in freight rail demand, and the substantial resources that seem likely to be focused on this cause, we believe that overall freight rail capacity would not be a limiting factor to the successful implementation of the biofuel requirements under EISA.

### 1.6.3 Changes in Freight Tonnage Movements Due to RFS2

In order to estimate the freight rail system impacts associated with biofuels transport under RFS2, we commissioned an analysis by Oak Ridge National Laboratories (ORNL) to examine fuel ethanol transportation, activity, and potential distribution constraints for the North American freight rail system.[416] The analysis found that biofuels transport is expected to constitute approximately 0.4% of the total freight tonnage for all commodities transported by the freight rail system through 2022. The results suggest that it should be feasible for the freight rail system to accommodate the additional biofuels freight associated with the RFS2.

For the analysis, we provided the estimated location of ethanol production facilities, sources of ethanol imports, and state-level consumption for the annual volumes of ethanol that we estimated would be consumed in response to the EISA.[YYY] We also provided the projected volumes of biodiesel and non-co-processed renewable diesel fuel that would be used. Due to the uncertainty associated with non-ethanol biofuels, biodiesel and non-co-processed renewable diesel fuel volumes were assumed to originate from the ethanol production facilities and follow projected ethanol use patterns in the analysis. This assumption seems reasonable, given the relatively small volumes of these non-ethanol biofuels relative to ethanol.

Rail traffic information from the 2006 Surface Transportation Board Carload waybill sample was incorporated into ORNL's North American Transportation Infrastructure Network Model to provide a baseline approximation of the current day freight rail system unstressed by the transport of EISA-mandated biofuels volumes. Freight rail activity for the unstressed baseline model was projected for 2012, 2014, and 2022 using information from the Commodity

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[XXX] See Section 1.6.3. of this RIA for a discussion of the increase in freight traffic due to the transport of the biofuels needed to comply with the RFS2 standards

[YYY] These inputs are summarized in the ORNL final report.

Origin-Destination Database of DOT's Freight Analysis Framework version 2 (FAF2) to identify potential distribution constraints for the North American freight rail system. FAF2 integrates data from a variety of sources to estimate commodity flows by different modes of transportation and related freight transportation activity among states, regions, and major international gateways. FAF2 provides freight transportation forecasts through 2035.

To estimate potential future constraints of the freight rail system, EISA-mandated biofuels volumes were superimposed onto the unstressed Infrastructure Network model for 2012, 2012, and 2022. For each forecast year, total biofuels demand includes biodiesel and non-co-processed renewable diesel fuel demand. As such, total biofuel demand for the forecast years were assumed to be 14.6, 17.5, and 35.1 billion gallons, respectively. See the ORNL report for additional assumptions and modeling details.

On average, 84% of the nation's freight rail system will not be affected by biofuels shipments under the RFS2 scenarios considered, according to the ORNL analysis. The 16% which will be impacted will see a 2.5% increase in freight rail traffic associated with biofuels shipments, on average.[ZZZ] Approximately 85% of all ethanol shipments are expected to originate in the Midwest, with approximately 24%, 15%, 13%, 8% and 6% of all unit train shipments of ethanol originating from Iowa, Nebraska, Illinois, Minnesota, and Indiana, respectively. The balance is expected to originate from the surrounding Midwestern states.

As such, the 16% of the freight rail system that is expected to see an increase in biofuels shipments under RFS2 will see it concentrated along rail corridors radiating out of the Midwest. Most high-volume ethanol movements are estimated to occur from the Midwest producing regions to high-demand regions, such as the northeast, west, and south. For instance, Midwest ethanol shipments destined for the west constitute about 19% of all ethanol shipments. Shipments destined from the Midwest to the Northeast constitute about 10% of all ethanol shipped while shipments to the southeast constitute another 10%. Shipments to the southwest constitute 7% of overall ethanol shipments as do shipments to the south. Interstate shipments account for 17% of all ethanol shipped. Shipments originating and terminating in the Midwest constitute approximately 31% of all ethanol unit train shipments. For all scenarios, the EISA-related transport impacts on the freight rail system were negligible.

The results of the analysis suggest that any additional stress placed upon the North American freight rail system by biofuels transport under EISA would have minimal impacts on transportation infrastructure overall since freight associated with biofuels constitutes only a small portion of the total freight tonnage for all commodities. The results of this analysis suggest that it should be feasible for the distribution infrastructure upstream of the terminal to accommodate the additional freight associated with this RFS2.

### 1.6.4 Rail Transportation System Accommodations

Many improvements to the freight rail system will be required in the next 15 years to keep pace with the large increase in the overall freight demand. Much of the projected increase in rail freight demand is associated with the expected rapid growth of inter-modal rail transport.

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[ZZZ] The overall increase in freight tonnage is 0.4% (2.5% x 16%)

Most of the needed upgrades to the freight rail system are not specific to the transport of renewable fuels and would be needed irrespective of the need for increased biofuel transport under the EISA. The modifications required to satisfy the increase in demand include upgrading tracks to allow the use of heavier trains at faster speeds, the modernization of train braking systems to allow for increased traffic on rail lines, the installation of rail sidings to facilitate train staging and passage through bottlenecks.

Some industry groups[AAAA] and governmental agencies in discussions with EPA and in testimony provided for the Surface Transportation Board (STB) expressed concerns about the ability of the rail system to keep pace with large increase in demand without the implementation of the RFS2 standards. A 27% overall increase in rail fright traffic is projected by 2022 without considering the potential impact of compliance with the RFS2 program. For example, the electric power industry has had difficulty keeping sufficient stores of coal in inventory at power plants due to rail transport difficulties and has expressed concerns that this situation will be exacerbated if rail congestion worsens. One of the more sensitive bottleneck areas with respect to the movement of ethanol from the Midwest to the East coast is Chicago. The City of Chicago commissioned its own analysis of rail capacity and congestion, which found that the lack of rail capacity is “no longer limited to a few choke points, hubs, and heavily utilized corridors.” Instead, the report finds, the lack of rail capacity is “nationwide, affecting almost all the nation’s critically important trade gateways, rail hubs, and intercity freight corridors.” This is due, in part, to the lack of critical linkages between the 27 major rail yards located in the Chicago-land area.

To help improve east-west rail connections through the city, federal, state, and local officials announced an agreement in 2006 to invest $330 million over three-years in city-wide rail infrastructure designed to improve the flow of rail traffic through the area. The State of Illinois, the City of Chicago, and seven Class I rail carriers, as well as Amtrak and Metra, the area's transit system, also committed $1.5 billion in improvements. Chicago is the largest rail hub in the country with more than 1,200 trains passing through it daily carrying 75% of the nation's freight valued at $350 billion; 37,500 rail freight cars pass through the city every day projected to increase to 67,000 by 2020. Chicago is the only city where all six Class I railroads converge and exchange freight. The plan calls for the creation of five rail corridors to aid in alleviating the bottleneck.

Significant private and public resources are focused on making the modifications to the rail system to cope with the increase in demand. Rail carriers report that they typically invest 16 to 18 billion dollars a year in infrastructure improvements.[417] Substantial government loans are also available to small rail companies to help make needed improvements by way of the Railroad Rehabilitation and Improvement Finance (RRIF) Program[BBBB], administered by Federal Railroad

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[AAAA] Industry groups include the Alliance of Automobile Manufacturers, American Chemistry Council, and the National Industrial Transportation League; governmental agencies include the Federal Railroad Administration (FRA), the General Accountability Office (GAO), and the American Association of State Highway Transportation and Officials (AASHTO). Testimony for the STB public hearings includes Ex Parte No. 671, *Rail Capacity and Infrastructure Requirements* and Ex Parte No. 672, *Rail Transportation and Resources Critical to the Nation’s Energy Supply*.

[BBBB] The RRIF program was established by the Transportation Equity Act for the 21st Century (TEA-21) and amended by the Safe Accountable, Flexible and Efficient Transportation Equity Act: a Legacy for Users

Administration (FRA), as well as Section 45G Railroad Track Maintenance Credits, offered by the Internal Revenue Service (IRS).

The RRIF program offers loans to railroads for a variety of capital purposes including track and equipment rehabilitation at “cost of money” for 25 year terms. Typically, short line railroads cannot secure this kind of funding in the private markets. Under this program, FRA is authorized to provide direct loans and loan guarantees up to $35.0 billion. Up to $7.0 billion is reserved for projects benefiting freight railroads other than Class I carriers. However, the program has lent less than $650 million to non-passenger rail carriers since 2002, according to the FRA/RRIF website.

The American Association of State Highway Transportation Officials (AASHTO) estimates that between $175 billion and $195 billion must be invested over a 20-year period to upgrade the rail system to handle the anticipated growth in freight demand, according to the report’s base-case scenario.[418] The report suggests that railroads should be able to provide up to $142 billion from revenue and borrowing, but that the remainder would have to come from other sources including, but not limited, to loans, tax credits, sale of assets, and other forms or public-sector participation. Given the reported historical investment in rail infrastructure, it may be reasonable to assume that rail carriers would be able to manage the $7.1 billion in annual investment from rail carriers that AASHTO projects would be needed to keep pace with the projected increase in freight demand.

The Association of American Railroads (AAR) estimates[419] that meeting the increase in demand for rail freight transportation will require an investment in infrastructure of $148 billion (in 2007 dollars) over the next 28 years and that Class I railroads' share is projected to be $135 billion, with $13 billion projected for short line and regional freight railroads.

In testimony before the STB, Class I railroads committed to working with all parties in the ethanol logistical chains to provide safe, cost-effective, and reliable ethanol transportation services as well as to resolve past freight rail capacity difficulties. Presumably, this commitment extends to the projected three-percent increase in overall freight tonnage envisioned herein.

However, the Government Accounting Office (GAO) found that it is not possible to independently confirm statements made by Class I rail carriers regarding future investment plans.[CCCC] In addition, questions persist regarding allocation of these investments, with the Alliance of Automobile Manufacturers, American Chemistry Council, National Industrial Transportation League, and others expressing concern that their infrastructural needs may be

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(SAFETEA-LU). RRIF funding may be used to: acquire, improve, or rehabilitate intermodal or rail equipment or facilities, including track, components of track, bridges, yards, buildings and shops; refinance outstanding debt incurred for the purposes listed above; and develop or establish new intermodal or railroad facilities.

[CCCC] The railroads interviewed by GAO were generally unwilling to discuss their future investment plans with the GAO. Therefore, GAO was unable to comment on how Class I freight rail companies are likely to choose among their competing investment priorities for the future, including those of the rail infrastructure, GAO testimony Before the Subcommittee on Surface Transportation and Merchant Marine, Senate Committee on Commerce, Science, and Transportation, U.S. Senate, *Freight Railroads Preliminary Observations on Rates, Competition, and Capacity Issues*, Statement of JayEtta Z. Hecker, Director, Physical Infrastructure Issues, GAO, GAO-06-898T Washington, D.C.: June, 21, 2006).

neglected by the Class I railroads in favor of more lucrative intermodal traffic. Moreover, the GAO has raised questions regarding the competitive nature and extent of Class I freight rail transport. This raises some concern that providing sufficient resources to facilitate the transport of increasing volumes of ethanol and biodiesel might not be a first priority for rail carriers. In response to GAO concerns, the Surface Transportation Board (STB) agreed to undertake a rigorous analysis of competition in the freight railroad industry.[DDDD]

Given the broad importance to the U.S. economy of meeting the anticipated increase in freight rail demand, and the substantial resources that seem likely to be focused on this cause, we believe that overall freight rail capacity would not be a limiting factor to the successful implementation of the biofuel requirements under the RFS2 standards. Evidence from the recent ramp up of ethanol use has also shown that rail carriers are enthusiastically pursuing the shipment of ethanol, although there is some indication that the Class I freight rail industry will expect ethanol to primarily be shipped by unit train from facilities that assemble unit trains which are developed and paid for by the ethanol industry.

Class 2 railroads have been particularly active in gathering sufficient numbers of ethanol cars to allow Class 1 railroads to ship ethanol by unit train. Based on this recent experience, we believe that biofuels will be able to compete successfully with other commodities in securing its share of freight rail service.

While many changes to the overall freight rail system are expected to occur irrespective of today’s final rule, several biofuel-specific modifications will be needed. Additional unit train and manifest rail receipt facilities will be needed to handle the volumes of ethanol and cellulosic distillate fuel that we project will be used to comply with the RFS2 standards. In the NPRM, we projected that unit train receipt facilities would be located at petroleum terminals and existing rail terminals. Based on industry input regarding the logistical hurdles in citing unit train receipt facilities at petroleum/existing rail terminals, we expect that such facilities will be constructed on dedicated property with rail access that is as close to petroleum terminals as practicable.[EEEE] We assumed that under the primary mid-ethanol and the low-ethanol control scenarios that all unit train and manifest rail receipt facilities would be capable of handling the receipt of both ethanol and cellulosic distillate fuel. There is no cellulosic distillate fuel under the high-ethanol scenario, thus all unit train receipt facilities would be dedicated to handling ethanol under the high-ethanol control scenario.

In the NPRM, we assumed that some new manifest rail receipt facilities for biofuels would be located at petroleum terminals. Since the NPRM we received industry input that it is unlikely that additional manifest rail receipt facilities could be located at petroleum terminals due to a lack of reasonable access to a rail line. Consequently, we are now assuming that additional manifest rail receipt facilities for biofuels would be placed at exiting rail terminals. We are assuming that biofuels will continue to be trans-loaded directly from rail cars to tank trucks at

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[DDDD] GAO, *Freight Railroads: Industry Health Has Improved, but Concerns about Competition and Capacity Should Be Addressed*, GAO-07-94 (Washington, D.C.: Oct. 6, 2006); GAO, *Freight Railroads: Updated Information on Rates and Other Industry Trends*, GAO-07-291R Freight Railroads (Washington, D.C.: Aug. 15, 2007).

[EEEE] Existing unit train receipt facilities have primarily followed this model.

rail terminals for shipment to petroleum terminals as is the case today, thereby obviating the need for biofuel storage at rail terminals.[FFFF] Some manifest rail receipt facilities would also handle biodiesel as well as ethanol, and cellulosic distillate fuel/renewable diesel fuel.

As part of Oakridge National Laboratory's study for EPA on the projected patterns of ethanol distribution from producer to terminal under the EISA, ORNL estimated the number of unit train receipt facilities.[420] The ORNL study used our NPRM estimate that all biofuel used to comply with the EISA (other than biodiesel) would be ethanol. Because unit train receipt facilities would handle both ethanol and cellulosic distillate fuel, the number of these facilities that would be needed is driven by the combined volume of these fuels that we project would used. Therefore, the ORNL estimate of the number of unit train receipt facilities for the NPRM control case is still very useful in estimating the number of such facilities under the control cases examined in this final rule. The NPRM control scenario assumed the use of 34.14 BGal/yr of ethanol by 2022. Under the high-ethanol control scenario in this final rule (FRM), we estimate that 33.24 BGal/yr of ethanol would be used by 2022. Given their similarity, we assumed that the ORNL results for the NPRM would be applicable to the FRM high-ethanol scenario for estimating the number of unit train receipt facilities required.

Based on our analysis of a spreadsheet used in the ORNL analysis, we determined that ORNL estimated that there would be approximately 210 unit train receipt facilities under the NPRM control case.[421] The ORNL estimate was based on an assumption by ORNL regarding the minimum annual throughput needed to justify the construction of a unit train facility (~20 MGal/yr) which we now believe to understate the throughput needed. Since the completion of the ORNL study, we received input from industry experts who are familiar with the construction of ethanol unit train receipt facilities that the minimum annual throughput for such a facility is approximately 230 million gallons per year. This minimum throughput volume assumes a fortuitous grouping of circumstances including low cost of the land needed, and ease of construction of the rail spur to the facility to a rail line. To provide a more realistic estimate under varied conditions, we assumed a minimum throughput volume of 280 MGal/yr.

We evaluated the location and annual throughput volumes of the unit train receipt facilities projected by ORNL. We consolidated the volumes from the smaller facilities projected by ORNL regionally to satisfy a minimum throughput volume of 280 MGal/yr while maintaining a reasonable trucking distance (<200 miles) from unit train facilities to petroleum terminals. Based on this analysis, we arrived at an estimate of 40 unit train receipt facilities to support the volumes of ethanol and cellulosic distillate fuel that we project would be used under the EISA. We estimated the additional transport by tank truck from these unit train facilities to petroleum terminals that would be needed to compensate for the reduced number of unit train receipt facilities compared to the ORNL study.[GGGG]

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[FFFF] In the NPRM, we assumed that trans-loading would only continue only until biofuel storage tanks could be constructed at rail terminals. Input from industry indicates that trans-loading will continue to be employed in the future. This input also indicates that construction of biofuel storage tanks at rail terminals is unlikely due to space and other constraints.

[GGGG] See Section 1.6.6 for a discussion of the tanker trucks needed to support the distribution of biofuels under the EISA. For a discussion of our estimation of ethanol and cellulosic distillate freight costs, see Sections 4.2.1.2 and 4.2.2.2 respectively in this RIA. The attribution of the costs of unit train facilities to the volumes of ethanol and cellulosic distillate fuel is discussed in Sections 4.2.1.1.2 and 4.2.2.1.3

We assumed that 40 unit train facilities would be needed under each of the 3 control scenarios that we evaluated. This may somewhat overstate the number needed under the primary mid-ethanol and the low ethanol scenarios since the total volume of ethanol and cellulosic distillate fuel is somewhat lower under these scenarios relative to the high-ethanol scenario. However, we believe that this is an appropriate approach since it provides some margin to compensate for the potential that there may be some instances where a unit train receipt facility may only handle ethanol or cellulosic distillate fuel (potentially increasing the overall number of unit train facilities needed slightly). We estimate that there would be 9 unit train receipt facilities to support the transport of biofuels under the AEO reference case and 3 under the RFS1 reference case. For the AEO reference case, this includes those unit train receipt facilities currently in place and those under construction. To estimate the number unit train facilities under the RFS1 reference case, we evaluated how many of these type of facilities were in place or under construction when historic ethanol consumption levels were consistent with the RFS1 case. Under the RFS1 reference case, we attributed the need for 37 additional biofuel unit train receipt facilities (40-3) to the implementation of the EISA. Under the AEO reference case, we attributed 31 additional unit train receipt facilities (40-9) to the EISA.

The construction of each of these unit train receipt facilities would require: the acquisition of land near a rail line and within trucking distance of the petroleum terminals that would be served, the construction of a rail spur and internal tracks to handle unit trains, facilities for the high-speed unloading of rail cars and loading of tank trucks, biofuel storage tanks and/or pipelines to ship biofuel to nearby petroleum terminals, and other miscellaneous biofuel handling equipment. For our analysis, we assumed that all unit train rail receipt facilities would construct biofuel storage tanks. Biofuels would be unloaded from unit trains into these storage tanks before being loaded into tank trucks for shipment to petroleum terminals. To the extent that some facilities are able to link to nearby petroleum terminals by pipeline or employ trans-loading, there would be less need for storage tanks at unit train receipt facilities. A large petroleum fuel terminal and transportation company recently announced a joint venture with a leading biofuel unit train receipt facility developer to facilitate the rapid expansion of ethanol logistics facilities throughout the U.S.[422]

A spreadsheet used in the ORNL analysis indicates that ORNL estimated that there would be 56 manifest rail receipt facilities for biofuels under the NPRM control case.[423] To provide some margin to compensate for the potential need for additional manifest rail receipt facilities beyond that indicated by the ORNL analysis, we used the estimate of 56 manifest rail facilities for each of the 3 FRM control scenarios relative to the RFS1 reference case.[HHHH] We estimated that an additional 43 manifest rail receipt facilities would be needed to support the transport of biofuels for the three FRM control cases relative to the AEO reference case. We arrived at this estimate by subtracting the number of manifest rail receipt facilities that could be attributed to the incremental increase in biofuel shipment volumes in going from the RFS1 to the AEO reference case from the number of facilities attributed to the EISA under the RFS1

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[HHHH] No deduction to the number of manifest rail receipt facilities attributed to the EISA was made based on the number of such facilities that would have been in place to support the transport of the volumes of biofuels corresponding to the RFS1 reference case.

reference case (56-13).[IIII] The construction of a new manifest rail receipt facilities at a rail terminal would involve the acquisition of a mobile trans-loading platform including fuel and fuel vapor transfer hoses, the preparation of spill containment for the area where trans-loading would take place, accommodations for recordkeeping and the preparation of bills of lading, and the installation of other miscellaneous equipment to support the trans-loading process.

A substantial number of additional rail cars would be needed to transport the volumes of ethanol, cellulosic distillate fuel, renewable fuel, and biodiesel that are projected to be used in response to the RFS2 standards. Biodiesel rail cars typically have a deliverable volume of 25,600 gallons, whereas the deliverable volume for ethanol rail cars is typically 29,000. We assumed that rail cars similar to those used for the transport of ethanol would be used to handle cellulosic distillate and renewable diesel fuels. Our estimation of the rail cars needed to transport ethanol and cellulosic distillate fuel under the 3 control scenarios is based on an interpolation of the results from the ORNL analysis for the NPRM control case (34.14 BG/yr of ethanol by 2022) and AEO reference case (13.18 BG/yr of ethanol by 2022). The underlying assumption in this approach is that the overall number of rail cars needed varies by the total volume of biofuel projected to be used under a given control scenario. Based on this approach, we estimate that 40,400 rail cars would be needed to transport the volumes of ethanol and cellulosic distillate fuel/renewable diesel fuel under the high-ethanol scenario, 36,200 under the primary mid-ethanol scenario, and 34,400 under the low-ethanol scenario**.** We subtracted the number of rail cars needed under the two reference cases to determine the incremental number of rail cars attributed to compliance with the EISA (see Table 1.6-1).

**Table 1.6-1.**
**Additional Rail Cars Needed by 2022 for Shipment of the Incremental RFS2 Volumes of Ethanol, and Cellulosic Distillate Fuel/Renewable Diesel Fuel**

| | Number of Rail Cars | |
|---|---|---|
| | Reference Case used for Comparison | |
| | RFS1 | AEO 2007 |
| Low-Ethanol Scenario | 24,600 | 12,600 |
| Mid-Ethanol Scenario | 20,400 | 8,300 |
| High Ethanol Scenario | 18,500 | 6,500 |

We estimated the number of rail cars that would be needed to transport biodiesel using the projected volume of biodiesel that we expect would be shipped by manifest rail and the assumed rail car volume and cycle time. We assumed a cycle time of one month for shipment by manifest rail car. We believe this is a conservatively high estimate given current industry experience and the potential for improvement in the future. We estimate that 1,370 rail cars would be needed by 2022 to transport the volume of biodiesel that we project will be used to satisfy the RFS2 standards. We estimate that 250 rail cars would be needed by 2022 to transport

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[IIII] The number of manifest rail receipt facilities attributed to the incremental increase in biofuel shipment volumes in going from the RFS1 to the AEO reference case was calculated by volume weighting.

the volume of biodiesel projected under the RFS1 reference case and 310 rail cars under the AEO reference case. Consequently, we attribute the construction of an additional 1,130 biodiesel rail cars to the implementation of the EISA under the RFS1 reference case and 1,060 under the AEO reference case. The total additional number of rail cars for the transport of ethanol, cellulosic distillate fuel/renewable diesel fuel, and biodiesel that we attribute to the implementation of the EISA is presented in Table 1.6-2.

**Table 1.6-2.**
**Additional Rail Cars Needed by 2022 for Shipment of**
**All Incremental RFS2 Biofuel Volumes**

| | Number of Rail Cars | |
|---|---|---|
| | Reference Case used for Comparison | |
| | RFS1 | AEO 2007 |
| Low-Ethanol Scenario | 25,800 | 13,700 |
| Mid-Ethanol Scenario | 21,500 | 9,400 |
| High Ethanol Scenario | 19,700 | 7,500 |

Our analysis of ethanol, biodiesel cellulosic distillate, and renewable diesel fuel rail car production capacity indicates that access to these cars should not represent a serious impediment to meeting the requirements under the RFS2 standards. Ethanol tank car production has increased approximately 30% per year since 2003, with over 21,000 tank cars expected to be produced in 2007. To accommodate the increased demand for ethanol tank cars, rail car producers converted existing boxcar production facilities to tank production facilities and brought on additional work shifts to adjust to rapidly changing to market conditions.

With the recent economic downturn, the backlog for railcars has decreased significantly. For example, the backlog for railcars of a major producer was approximately 7,000 railcars in 2009, but dropped to approximately 1,200 railcars scheduled for delivery in 2010. This has led to the closure of several railcar production facilities. We believe that the excess railcar production capacity will allow the industry to rapidly respond to potential increases in railcar demand due to ethanol, biodiesel, cellulosic distillate, and renewable diesel fuels, when the need arises.

### 1.6.5 Marine Transportation System Accommodations

The American Waterway's Association expressed concerns about the need to upgrade the inland waterway system in order to keep pace with the anticipated increase in overall freight demand. The majority of these concerns have been focused on the need to upgrade the river lock system on the Mississippi river to accommodate longer barge tows and on dredging inland waterways to allow for movement of fully loaded vessels. We do not anticipate that a substantial fraction of biofuels will be transported via these arteries. Thus, we do not believe that the ability to ship biofuels by inland marine will represent a serious barrier to the implementation of the requirements under RFS2 standards. Substantial quantities of the corn ethanol co-product dried distiller grains (DDG) is expected to be exported from the Midwest via the Mississippi river as the US demand for DDG becomes saturated. We anticipate that the volume of exported DDG would take the place of corn that would be shifted from export to domestic use in the production of ethanol. Thus, we do not expect the increase in DDG exports to result in a substantial increase in river freight traffic.

A number of new barges would be needed to transport the volumes of biofuels that are projected to be used in response to the RFS2 standards. We assumed the use of tank barges with a carrying capacity of 10,000 barrels (42,000 gallons). We understand that the tank barge industry is trending towards the use of tank barges with a carrying capacity of 30,000 barrels. Thus, our assumed use of 10,000 barrel barges may overstate the number of barges that would be needed. Our estimation of the barges needed to transport ethanol and cellulosic distillate fuel under the 3 control scenarios is based on an interpolation of the results from the ORNL analysis for the NPRM control case (34.14 BG/yr of ethanol by 2022) and AEO reference case (13.18 BG/yr of ethanol by 2022). The underlying assumption in this approach is that the over all number of barges needed varies by the total volume of ethanol and cellulosic distillate fuel projected to be used under a given control scenario. Based on this approach, we estimate that 167 barges would be needed to transport the volumes of ethanol and cellulosic distillate fuel/renewable diesel fuel under the high-ethanol scenario, 150 under the primary mid-ethanol scenario, and 143 under the low-ethanol scenario. We subtracted the number of barges needed under the two reference cases to determine the incremental number of rail cars attributed to compliance with the EISA (see Table 1.6-3).

**Table 1.6-3.**
**Additional Barges Needed by 2022 for Shipment of the Incremental RFS2 Volumes of Ethanol, and Cellulosic Distillate Fuel/Renewable Diesel Fuel**

| | Number of Barges | |
|---|---|---|
| | Reference Case used for Comparison | |
| | RFS1 | AEO 2007 |
| Low-Ethanol Scenario | 95 | 45 |
| Mid-Ethanol Scenario | 78 | 28 |
| High Ethanol Scenario | 71 | 21 |

We estimated the number of barges that would be needed to transport biodiesel using the projected volume of biodiesel that we expect would be shipped by barge and the assumed barge volume and cycle time. We assumed a 2 week barge cycle time, which we understand to be typical given the markets where we expect most barge shipments would occur.[JJJJ] We estimate that 41 barges would be needed by 2022 to transport the volume of biodiesel that we project will be used to satisfy the RFS2 standards. We estimate that 7 barges would be needed by 2022 to

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[JJJJ] We believe most barge shipments of biofuels would originate and terminate in the Northeast. Cycle time refers to the time needed to complete one delivery and return to the origin including the time to prepare for the next shipment.

transport the volume of biodiesel projected under the RFS1 reference case and 9 barges under the AEO reference case. Consequently, we attribute the construction of an additional 34 biodiesel barges to the implementation of the EISA under the RFS1 reference case and 32 under the AEO reference case. The total additional number of barges for the transport of ethanol, cellulosic distillate fuel/renewable diesel fuel, and biodiesel that we attribute to the implementation of the EISA is presented in Table 1.6-4.

**Table 1.6-4.**
**Additional Barges Needed by 2022 for Shipment of All Incremental RFS2 Biofuel Volumes**

| | Number of Barges | |
|---|---|---|
| | Reference Case used for Comparison | |
| | RFS1 | AEO 2007 |
| Low-Ethanol Scenario | 129 | 67 |
| Mid-Ethanol Scenario | 112 | 60 |
| High Ethanol Scenario | 105 | 53 |

The U.S. tank barge fleet currently numbers 3,600.[424] In 2004, over 500 barges of all types were added to the U.S. barge fleet. Given the gradual ramp up in demand for shipment of biofuels by barge over time, we believe that the addition to the fleet of the barges estimated to be needed to transport biofuels can be accommodated by the industry.

As discussed in Section 1.5.2. of this RIA, we are projecting significant imports of ethanol by 2022. To estimate which ports would receive ethanol imports we gave priority to ports that have a history of receiving ethanol imports from Brazil and Caribbean Basin Initiative Counties[KKKK] according to company-level historical fuel import data from the Energy Information Administration (EIA).[425] Additional ports were selected from those that have a history of receiving finished gasoline imports. Ports were selected in States that could not satisfy their internal ethanol demand from in-State production and from those ports that were closest to large demand centers. We estimate that a total of 30 ports would receive imported ethanol by 2022. The list of ethanol import ports was provided to ORNL as an input to the ethanol transportation analysis that they conducted for EPA.[426] Under the high-ethanol option, we estimate that the 18 ports which did not receive ethanol in the past would need to install/modify ethanol receipt facilities including piping, pumps, vapor handling systems, and ethanol storage tanks while ports that had received ethanol in the past would primarily need to install additional ethanol storage tanks. We project that under the primary mid-ethanol scenario that 15 new ethanol import locations would be added and that under the low ethanol scenario there would be 14 new ethanol import locations. We used these estimates relative to both the RFS1 and AEO reference cases since we expect that the increase in ethanol imports would most appropriately be attributed to the incremental increase in ethanol use levels above those reflected under both the

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[KKKK] Caribbean Basin Initiative countries receive special exemptions from U.S. ethanol import tariffs (See Section 1.5 of this RIA regarding the source of ethanol imports and for additional discussion regarding how we estimated where ethanol imports would enter the U.S..

AEO and RFS1 reference cases. We believe that all the ports where ethanol would be imported would be incorporated into existing petroleum terminals. Hence, the need for additional ethanol storage as well as outgoing ethanol shipping facilities would be covered within the context of our estimation of the upgrades needed to petroleum terminal facilities.

As part of Oakridge National Laboratory's study for EPA on the projected patterns of ethanol distribution from producer to terminal under the EISA, ORNL estimated the number of barge receipt facilities that would be needed to support biofuel shipments within the U.S.[427] Based on our analysis of a spreadsheet used in the ORNL analysis, we determined that ORNL estimated that there would be approximately 57 barge facilities under the NPRM control case.[428] Since the NPRM control case has a somewhat higher total biofuel volume than under the FRM high-ethanol control scenario, we believe that the ORNL estimate of the number of barge receipt facilities needed for the NPRM control scenario provides a reasonable (although perhaps conservatively high) estimate of the number of such facilities that would be needed under the high-ethanol scenario.

We assumed that all biofuel barge receipt facilities would handle ethanol and cellulosic distillate fuel and that some of these facilities would handle biodiesel. To compensate for the potential that there may be some instances where a manifest rail receipt facility might handle ethanol but not cellulosic distillate fuel or vice-versa (perhaps increasing the number of unit train facilities slightly), we assumed that 57 manifest rail receipt facilities would also be needed under the mid-ethanol and low-ethanol scenarios. Our analysis of the aforementioned ORNL spreadsheet indicates that ORNL estimated there would be approximately 4 barge receipt facilities under the RFS1 reference case. Therefore, we estimate that an additional 53 barge receipt facilities would need to be configured to receive biofuels in order to facilitate compliance with the RFS2 program relative to the RFS1 reference case. By interpolating between the ORNL results for the RFS1 reference case and the NPRM control case, we estimated that 16 barge receipt facilities would be needed under the AEO reference case. Therefore, we estimate that an additional 41barge receipt facilities would need to be configured to receive biofuels in order to facilitate compliance with the RFS2 program relative to the AEO reference case

We believe that barge receipt facilities that receive shipments of biofuels would be those that already handle the receipt of petroleum-based fuels and which are incorporated into petroleum terminals or would be linked to unit train receipt facilities. Such facilities would need to install/modify piping, pumps, vapor handling systems. The need for biofuel storage tanks and other facilities to handle the storage and transfer of biofuels to other means of distribution at such is addressed within the context of the additional facilities needed at petroleum terminals and unit train facilities.

### 1.6.6 Road Transportation System Accommodations

A substantial number of tank trucks would be needed to distribute the additional volume of biofuels that we project would be used to meet the RFS2 volumes. In all cases, a tank truck capacity of 8,000 gallons was assumed. Larger tank trucks are permitted in some areas, so this assumption will tend to overestimate of the number of tank trucks needed. We assumed that tank trucks similar to those used for the transport of ethanol would be used to handle cellulosic distillate and renewable diesel fuels.

Our estimation of the tank trucks needed to transport ethanol and cellulosic distillate fuel under the 3 control scenarios is based on an interpolation of the results from the ORNL analysis for the NPRM control case (34.14 BG/yr of ethanol by 2022) and AEO reference case (13.18 BG/yr of ethanol by 2022). The underlying assumption in this approach is that the overall number of tank trucks needed varies by the total volume of ethanol and cellulosic distillate fuel projected to be used under a given control scenario. We increased the estimated number of tank trucks needed from that which we arrived at from this interpolation to compensate for our reduction in the number of unit train facilities that would be constructed from the estimate in the ORNL study.

The volume of biofuels shipped to the unit train facilities under the ORNL analysis which we consolidated into larger unit train receipt facilities represents 41% of the total volume shipped to unit train facilities (12.6 BG/yr out of 21.4 BG/yr in 2022 under the NPRM control case). We compared the location of the 170 unit train facilities that we consolidated into the remaining 40 such facilities from the ORNL analysis to the location of the petroleum terminals that these facilities were intended to service. Based on this comparison, we estimated that 41% of the volume of biofuels shipped by unit train would need to be shipped 3 times farther on average to reach the petroleum terminals serviced than under the ORNL analysis. We assumed that this would result in a 3 fold increase in the number of trucks needed to take this volume from the unit train facility to the petroleum terminal.[LLLL] The majority of the number tank trucks which ORNL estimated would be needed are attributed to the transport of biofuels from rail receipt facilities to petroleum terminals. Consequently, we believe that a reasonable (albeit conservatively high) estimate of the increase in the number of tank trucks that would be needed due to our decrease in the number of unit train facilities can be arrived at by multiplying the fraction of biofuels shipped by unit train that is attributed to consolidated unit train terminals (41% of the total volume shipped by unit train) by the average increase in shipping distance for the affected volume (factor of 3). By so doing, we arrived at an estimate that the reduction in the number of unit train receipt facilities would result in a 23% increase in the number of tank trucks needed compared to that indicated by interpolation of the results from the ORNL study

Based on this approach, we estimate that 1,940 tank trucks would be needed to transport the volumes of ethanol and cellulosic distillate fuel/renewable diesel fuel under the high-ethanol scenario, 1,720 under the primary mid-ethanol scenario, and 1,620 under the low-ethanol scenario. We subtracted the number of tank trucks which ORNL estimated would be needed under the two reference cases to determine the incremental number of tank trucks attributed to compliance with the EISA (see Table 1.6-5).

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[LLLL] This may somewhat overstate the number of additional tank trucks needed given that the tank truck loading/unloading time remains constant. ORNL assumed a relatively short shipping distance from rail receipt facility to petroleum terminal.

### Table 1.6-5.
### Additional Tank Trucks Needed by 2022 for Shipment of the Incremental RFS2 Volumes of Ethanol, and Cellulosic Distillate Fuel/Renewable Diesel Fuel

| | Number of Biofuel Tank Trucks | |
|---|---|---|
| | Reference Case used for Comparison | |
| | RFS1 | AEO 2007 |
| Low-Ethanol Scenario | 1,490 | 1,080 |
| Mid-Ethanol Scenario | 1,230 | 820 |
| High Ethanol Scenario | 1,120 | 710 |

To estimate the number of tank trucks needed to transport biodiesel to petroleum terminals we assumed 6 shipments per day per truck from production facilities to terminals. We believe that a short shipping distance for tank truck transport from biodiesel production facilities is justified based on the widespread dispersion and the fact that some would be located at petroleum terminals. We estimate that 150 tank trucks would be needed by 2022 to transport the volume of biodiesel that we project will be used to satisfy the RFS2 standards. We estimate that 30 tank trucks would be needed by 2022 to transport the volume of biodiesel projected under the RFS1 reference case and 35 tank trucks under the AEO reference case. Consequently, we attribute the construction of an additional 130 biodiesel tank trucks to the implementation of the EISA under the RFS1 reference case and 120 under the AEO reference case. The total additional number of tank trucks for the transport of ethanol, cellulosic distillate fuel/renewable diesel fuel, and biodiesel that we attribute to the implementation of the EISA is presented in Table 1.6-6.

### Table 1.6-6.
### Additional Tank Trucks Needed by 2022 for Shipment of All RFS2 Incremental Biofuel Volumes

| | Number of Biofuel Tank Trucks | |
|---|---|---|
| | Reference Case used for Comparison | |
| | RFS1 | AEO 2007 |
| Low-Ethanol Scenario | 1,610 | 1,200 |
| Mid-Ethanol Scenario | 1,350 | 940 |
| High Ethanol Scenario | 1,240 | 830 |

In Section 1.6.8 of this RIA we discuss our estimation of the number of tank trucks than might potentially be needed to transport butane to terminals for E85 blending. The results of this analysis are presented in Table 1.6-7.

**Table 1.6-7.**
**Estimated Number of Tank Trucks Needed for Shipment of Butane[a]**

| | Number of Tank Trucks Needed to Transport Butane | | |
|---|---|---|---|
| | Low-Ethanol Scenario | Primary Mid-Ethanol Scenario | High-Ethanol Scenario |
| Tank Truck (8,200 gallons) | 2,165 | 3,280 | 5,530 |

[a] If a solution to the current difficulty in blending E85 to meet minimum volatility specifications can not be arrived upon by ASTM International to allow the use of commonly available gasoline blendstocks.

Concerns have been raised in the trade press regarding the ability of the trucking industry to attract a sufficient number of drivers to keep pace with demand. We used estimates of the number of truck drivers required to transport biofuels from the ORNL report as a basis for our estimate of the number of truck drivers that would be needed to transport the additional volume of biofuels attributed to the RFS2 program. Given the volume of butane required for blending into E85, typical travel distances, etc., we estimated that the number of truck drivers required to transport butane was approximately 1,500. Similar inputs were used to estimate the number of truck drivers required to transport non-ethanol biofuels; this number was approximately 300. When combined with the estimates from ORNL, the number of truck drivers required to transport biofuel feedstocks and finished product is approximately 5,300 drivers.[MMMM]

According to a 2005 study commissioned by the American Trucking Association (ATA), the motor carrier industry will face a shortage of qualified professional long-haul truck drivers by 2014.[429] In the study, ATA found that the long-haul, heavy-duty truck transportation industry in the United States is currently experiencing a national shortage of 20,000 truck drivers and, if the current trend continues, that shortage of long-haul truck drivers could increase to 111,000 by 2014. ATA projected the need for additional 54,000 drivers each year. The trucking industry is active in a number of efforts to attract and retrain a sufficient number of new truck drivers including ATA's National Truck Driver Recruiting Campaign and Driver Tuition Finance Program.

As discussed above, we estimate that the growth in the transportation of biofuels by truck through 2022 due to the RFS2 standards would result in the need for a total of approximately 5,300 additional trucks drivers for the transport of biofuel feedstocks and finished products. Given the relatively small number of new truck drivers needed to transport the volumes of biofuels projected to be used to comply with the RFS2 standards through 2022 compared to the total expected increase in demand for drivers over the same time period (>750,000), we do not expect that the implementation of the RFS2 standards would substantially exacerbate the potential for an overall shortage of truck drivers. Discussions with transport industry officials support this conclusion. However, specially-certified drivers are required to transport biofuels because these fuels are classified as hazardous liquids. Thus, there may be a heightened level of concern about the ability to secure a sufficient number of such specially-certified drivers to

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[MMMM] This is the maximum number of drivers that would be needed under any control scenario. Somewhat fewer drivers would be needed under the mid-ethanol and low-ethanol scenarios.

transport biofuels. The trucking industry is involved in efforts to streamline the certification of drivers for hazardous liquids transport. We do not anticipate that the need for special hazardous liquids certification for biofuels truck drivers of would substantially interfere with the ability to transport the projected volumes of biofuels by tank truck. We project that tank truck deliveries of biofuels would typically be accomplished within an 8 hour shift allowing the driver to return home each evening.[NNNN] The ATA sponsored study indicated that there was particular difficulty in attracting and retaining drivers for long haul routes the keep the driver away from home overnight. Thus, driving a tank truck (with typical 8 hour shift) may be relatively more attractive compared to a long haul truck driving position.

Truck transport of biofuel feedstocks to production plants and finished biofuels and co-products from these plants naturally is concentrated on routes to and from these production plants. This may raise concerns about the potential impact on road congestion and road maintenance in areas in the proximity of these facilities. We do not expect that such potential concerns would represent a barrier to the implementation of the RFS2 standards. Distant truck traffic associated with the plant will be diffuse. Hence, we expect that impacts associated with such distant traffic are negligible. Routes in close proximity to plants may require repaving as a result of construction traffic associated with the facility. As such, the repaved routes would be more capable of handling additional truck traffic associated with production at the plants. The improved routes can also be expected to provide benefits for communities in close proximity to the production plant as well as lower maintenance costs. The potential impact on local road infrastructure and the ability of the road net to be upgraded to handle the increased traffic load is an inherent part in the placement of new biofuel production facilities. Consequently, we expect that any issues or concerns would be dealt with at the local level. The transport of biofuel feedstocks is discussed in Section 1.3.3 of this RIA.

### 1.6.7 Petroleum Terminal Accommodations

Petroleum terminals will need to install additional storage capacity to accommodate the volume of ethanol, cellulosic distillate fuel/renewable diesel fuel, and biodiesel that we anticipate will be used in response to the RFS2 standards. We estimate that it would be necessary to maintain an inventory level of 15% of the annual consumption of a given biofuel at the terminal level in order to provide a sufficient downstream buffer to ensure consistent supply. We chose a working inventory level of 15% rather than the 10% that is typical for petroleum-based fuels to compensate for the potential increase in temporary disruptions in biofuel delivery compared to petroleum-based fuels. We believe that this is appropriate due to the reliance on rail, barge, and truck for the transport of biofuels in our analysis as opposed to use of pipelines for the shipment of petroleum-based fuels. The need for additional biofuel storage volume at terminals to provide a buffer for interruptions in delivery may be reduced somewhat to the extent that pipelines play a role in the distribution of biofuels. We further estimate that an additional 30% of storage capacity would be needed as working space to accommodate biofuel deliveries.[OOOO] Our estimates of the biofuel storage capacity needed at petroleum terminals by 2022 to facilitate the

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[NNNN] A small fraction of biofuels deliveries may require a sleep-over on the road of the driver due to limitations on the amount of time a driver can spend behind the wheel in a day.

[OOOO] Petroleum terminals typically allow an additional 30 percent of storage capacity (in relation to the amount provided for working inventory) to accommodate the receipt of petroleum products.

distribution of the volume of biofuels that we project would be used to meet the RFS2 volumes are based on the application of these working inventory and working space estimates. These estimates are presented in Table 1.6-8.

**Table 1.6-8.**
**Total Biofuel Storage Capacity needed at Petroleum Terminals by 2022 to Handle the RFS2 Volumes**

| | Biofuel Tankage (Mbbl) | | |
|---|---|---|---|
| | Low-Ethanol Scenario | Mid-Ethanol Scenario | High-Ethanol Scenario |
| Ethanol | 81.2 | 103.9 | 149.7 |
| Cellulosic Distillate Fuel/ Renewable Diesel Fuel | 43.0 | 30.3 | NA |
| Biodiesel | 7.2 | 7.2 | 7.2 |

To estimate of the additional biofuel storage tank capacity that should be attributed to the incremental RFS2 biofuel volumes relative to the 2 reference cases, we subtracted the volume which would have been in place regardless of the RFS2 program under the 2 reference cases. The same working inventory and working space estimates were used to estimate the volume of biofuel storage under the reference cases.

Overall demand for the gasoline motor vehicle fuel is expected to remain relatively constant through 2022 whereas demand for compression ignition vehicle fuel is anticipated to increase by over 10% over the same time period.[430] We expect that much of the demand for new ethanol storage capacity could be accommodated by modifying storage tanks that had previously been used for the gasoline that would be displaced by ethanol. Due to the lower energy density of ethanol relative to gasoline (67%), we project that only 67% of the demand for new ethanol storage might potentially be accommodated by modifying existing gasoline tanks for ethanol service. Likewise, we anticipate that much of the demand for cellulosic distillate fuel/renewable diesel fuel storage capacity might be satisfied by dedicating storage tanks that would have been constructed to store petroleum-based diesel fuel to instead store these biofuels. Due to the anticipated lower energy density of cellulosic distillate fuel relative to petroleum-based diesel fuel (~90% of petroleum-based diesel fuel), we project that only 90% of the demand for new cellulosic distillate/renewable diesel fuel storage might potentially be accommodated by modifying existing gasoline tanks for cellulosic distillate/renewable diesel fuel service. To provide some margin to compensate for the need for a greater degree of new tank construction than that indicated by the above analysis, we assumed that 5% of the tanks which might have been rededicated tanks previously used for petroleum-based fuels would instead be new construction. The rededication to ethanol service of storage tanks previously used to store gasoline involves lining the tank and other miscellaneous modifications to ensure the tank is compatible with ethanol. We assume that no changes would be needed to petroleum-based diesel fuel storage tanks to allow them to be used to store cellulosic distillate fuel/renewable diesel fuel. Since biodiesel storage tanks need to be insulated and heated under cold conditions, we assumed that all of the need for additional biodiesel storage capacity would be satisfied through new construction.

The volume of new biofuel storage capacity that we project would be needed as a result of the implementation of the EISA under the 2 reference cases is presented in Tables 1.6-9 and 1.6-10.

## Table 1.6-9.
## Additional Biofuel Storage Capacity at Petroleum Terminals by 2022 to Meet the EISA Volumes Relative to the RFS1 Reference Case[a]

| | Biofuel Tankage (Mbbl) | | |
|---|---|---|---|
| | Low-Ethanol Scenario | Mid-Ethanol Scenario | High-Ethanol Scenario |
| Ethanol, Total | 48.5 | 70.2 | 116.9 |
| Ethanol, New Construction | 17.6 | 25.5 | 42.5 |
| Ethanol, Retrofitted Tanks | 30.9 | 44.7 | 74.4 |
| Cellulosic Distillate Fuel/Renewable Diesel Fuel, Total | 43.0 | 30.3 | NA |
| Cellulosic Distillate Fuel/Renewable Diesel Fuel, New Construction | 6.2 | 4.4 | NA |
| Cellulosic Distillate Fuel/Renewable Diesel Fuel, Rededicated Tanks | 36.8 | 25.9 | NA |
| Biodiesel, New Construction | 5.9 | 5.9 | 5.9 |
| All Biofuels, New Construction | 29.7 | 35.8 | 48.4 |
| All Biofuels, Retrofitted Tanks | 30.9 | 44.7 | 74.4 |
| All Biofuels, Redicated Tanks | 36.8 | 25.9 | 0 |

[a] "Retrofitted" refers to tanks that need significant changes to be made suitable for biofuel storage. "Rededicated" refers to tanks that need essentially no changes to be made suitable for biofuel storage.

## Table 1.6-10.
## Additional Biofuel Storage Capacity at Petroleum Terminals by 2022 to Meet the EISA Volumes Relative to the AEO Reference Case[a]

| | Biofuel Tankage (Mbbl) | | |
|---|---|---|---|
| | Low-Ethanol Scenario | Mid-Ethanol Scenario | High-Ethanol Scenario |
| Ethanol, Total | 20.0 | 41.7 | 88.5 |
| Ethanol, New Construction | 12.7 | 26.5 | 56.3 |
| Ethanol, Retrofitted Tanks | 7.3 | 15.2 | 32.2 |
| Cellulosic Distillate Fuel/Renewable Diesel Fuel, Total | 43.0 | 30.3 | NA |
| Cellulosic Distillate Fuel/Renewable Diesel Fuel, New Construction | 6.2 | 4.4 | NA |
| Cellulosic Distillate Fuel/Renewable Diesel Fuel, Rededicated Tanks | 36.8 | 25.9 | NA |
| Biodiesel, New Construction | 5.5 | 5.5 | 5.5 |
| All Biofuels, New Construction | 24.4 | 36.4 | 61.8 |
| All Biofuels, Retrofitted Tanks | 7.3 | 15.2 | 32.2 |
| All Biofuels, Rededicated Tanks | 36.8 | 25.9 | 0 |

[a] "Retrofitted" refers to tanks that need significant changes to be made suitable for biofuel storage. "Rededicated" refers to tanks that need essentially no changes to be made suitable for biofuel storage.

Concerns have been raised by terminal operators in the Eastern U.S. about the ability of some terminals to install the needed storage capacity due to space constraints and difficulties in securing permits.[431] We acknowledge that it may not be possible for some terminals that have become surrounded by urban growth over time to install additional storage tanks within the boundaries of their existing facilities. However, we believe that there are ways to manage this situation. The areas served by existing terminals often overlap. In such cases, one terminal might be space constrained while another serving the same area may be able to install the additional capacity to meet the increase in demand. Terminals with limited biofuel storage could receive truck shipments of ethanol from terminals with more substantial biofuel storage capacity. In cases where it is impossible for existing terminals to sufficiently expand their storage capacity due to a lack of adjacent available land or difficulties in securing the necessary permits or to make arrangements to sufficiently reduce the need for such additional storage, new satellite storage or new separate terminal facilities may be need for additional biofuel storage. However, we believe that there will be few (if any) such situations.

As discussed below, we project that all terminals that distribute gasoline would install ethanol blending capability in response to the RFS2 standards. We estimate that approximately 91% of terminals that distribute diesel would install biodiesel blending/storage capability under the RFS2 standards. Therefore, in the case of biodiesel, those terminals that would experience that most difficulty in installing new storage capacity would have some opportunity to forgo bringing biodiesel into their terminal

Another question is whether the storage tank construction industry would be able to keep pace with the increased demand for new tanks that would result from today’s proposal. The storage tank construction industry recently experienced a sharp increase in demand after years of relatively slack demand for new tankage. Much of this increase in demand was due to the unprecedented increase in the use of ethanol. Storage tank construction companies have been increasing their capabilities which had been pared back during lean times. Given the projected gradual increase in the need for biofuel storage tanks, it seems reasonable to conclude that the storage tank construction industry would be able to keep pace with the projected demand.

Petroleum terminals would need to install additional equipment to blend ethanol, cellulosic distillate fuel/renewable diesel fuel, and biodiesel into petroleum-based fuels. In the case of ethanol other miscellaneous upgrades to piping, pumps, seals, and vapor recovery systems would also be needed to ensure ethanol compatibility. In the case of biodiesel, piping and blending systems would need to be heated/insulated under cold conditions. All terminals with biofuel blending capability would need to provide facilities for receipt of biofuels via tank truck.

There are currently 1,063 petroleum terminals that carry gasoline.[432] We project that 899 of these terminals (85% of the total) would install E10 blending equipment absent the implementation of the RFS2 requirements in order to support the consumption of 13.18 BGY of ethanol by 2022 under the AEO reference case. This is based on 85% of the gasoline needing to be blended with ethanol in order to consume 13.18 BGY of ethanol considering the projected use levels of E10 versus E85 and total motor vehicle fuel consumption in 2022.[433] We project that essentially all gasoline would be either E10 or E85 by 2022 under the RFS2 standards. Thus, we estimate that all terminals would need to have ethanol blending capability to support the use of the volume of ethanol we project would be used under the RFS2 standards. Based on our projection that 899 terminals would install ethanol blending capability absent the RFS2 standards under AEO reference case, we estimate that 164 terminals would need to install ethanol blending equipment to meet the RFS2 volumes relative to the AEO reference case.

The estimated number of terminals that would need to install ethanol blending capability as a result of the RFS2 standards relative to the RFS1 reference case is based on an extrapolation of the estimate for the AEO reference case. The volume of ethanol projected to be used under the RFS1 reference case is 53% of the volume projected to be used under the AEO reference case. We estimated that the number of terminals that blend ethanol under the RFS1 reference case is 53% of the number under the AEO reference case (899 x 53% = 481). Based on this, we estimate that an additional 582 terminals would install ethanol blending capability to meet the RFS2 volumes under the RFS1 reference case.

We estimate that E85 would need to be reasonably available in 70% of the nation in order to support the use of the projected volume of E85 needed to comply with the RFS2 standards under the high-ethanol scenario.[PPPP] To provide a conservatively high estimate, we are projecting that 90% of all gasoline terminals (931) would need to install E85 blending capability by 2022 under the high-ethanol scenario. The remaining terminals (132 out of a total of 1,063) would only have E10 blending capability in 2022 under the high-ethanol scenario.

Under the primary mid-ethanol scenario, we estimate that 60% of the nation would need to have reasonable access to E85 in order to support the use of the projected volume of E85 needed to comply with the RFS2 standards. Our estimate of the number of terminals that would need to install E85 blending capability under the mid-ethanol scenario is based on the ratio of the percent of the country which would need to have reasonable access to E85 under the mid-ethanol scenario relative to the high-ethanol scenario. By multiplying our 90% estimate of the number of terminals that would need to install E85 under the high-ethanol scenario by 60%/70%, we arrived at an estimate of 77% of all gasoline terminals (820) having E85 access under the mid-ethanol scenario. Under the low-ethanol scenario, we estimate that 40% of the nation would need to have reasonable access to E85 in order to support the use of the projected volume of E85 needed to comply with the RFS2 standards. We used the same approach outlined above to estimate that 51% of all gasoline terminals (547) would install E85 blending capability under the low-ethanol scenario.

We estimate that the terminals which would have installed E10 blending capability absent the RFS2 standards would upgrade their E10 blending facilities to accommodate E85 as well as E10. This is based on the assumption that those terminals that were the first to blend E10 would also be the first to begin blending E85. Input from terminal operators indicates that the modification of E10 blending equipment to handle E85 primarily involves an upgrade to the blending equipment software.[QQQQ] We estimate that the vapor recovery systems at all terminals that had not received ethanol before would need to be upgraded to handle ethanol-blended

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[PPPP] A discussion of our E85 use projections is contained in chapter 1.7 of this RIA.

[QQQQ] Additional ethanol storage and modifications to terminal piping would also be needed to supply additional quantity of ethanol needed to blend E85.

gasoline.  The potential need to provide special blendstocks at petroleum terminals for the manufacture of E85 is discussed in Section 1.6.8 of this RIA.

Our estimate of the number of terminals that would install biodiesel blending capability under the RFS2 standards is based on an extrapolation of the analysis conducted for the NPRM. We estimate that 853 terminals handle diesel fuel.[434] We estimate that approximately 62.5 billion gallons of diesel fuel would be used in 2022.[RRRR] Thus, the average diesel throughput per terminal would be approximately 73.2 MGY.  In the NPRM analysis, we estimate that on a national average basis biodiesel would represent approximately 2.9% of the diesel fuel pool.  For the purposes of our calculation of the number of terminals that would carry biodiesel, we assumed that 2.9% of the diesel fuel they dispense would be biodiesel.  This is likely to result in a conservatively high number of terminals that would need to carry biodiesel, since those terminals that do carry biodiesel would be expected too blend at higher than the national average concentration.  Assuming that 2.9% of a terminal's diesel fuel throughput would be biodiesel, we arrive at an estimate that 377 terminals would need to blend biodiesel to support the projected use of 810 MGY of biodiesel assumed to be used by 2022 under the RFS2 standards in the NPRM.

We estimated the number of terminals that would need to blend biodiesel for our FRM analysis by increasing the NPRM estimate in proportion to volume of biodiesel that we project would be used in the FRM by 2022 relative to that projected in the NPRM (1,671 Mgal/yr  / 810 Mgal/yr).  By so doing, we estimate that 777 terminals will be needed to blend biodiesel by 2022 to support the use of the biodiesel volume projected to be used in this FRM.  We estimate that 200 terminals would need to store/blend biodiesel in order to support the use of volume of biodiesel that we estimate would be used as a result of the RFS2 standards relative to the AEO 380 MGY 2022 baseline.  Thus, we project that 637 additional terminals would blend biodiesel as a result of the RFS2 standards under the RFS1 reference case and 600 under the AEO reference case.

The Independent Fuel Terminals Operators Association (IFTOA) stated that terminals are concerned that the market would not be able to adapt in time to ensure that the necessary distribution infrastructure accommodations are in place to support compliance with the timetable for the implementation of the RFS2 standards.[435] Based on this concern, in a presentation at the recent SAE government-industry conference IFTOA suggested that EPA should consider reducing and or slowing the pace of the implementation of the RFS2 standards in order to allow the market sufficient time to adjust.[436] We believe that given the time over which biofuel volumes ramp up under the RFS2 standards, it should be feasible for terminals to adapt sufficiently within the time frame established by the EISA.

### 1.6.8 Potential Need for Special Blendstocks at Petroleum Terminals for E85

ASTM International is considering a proposal to lower the minimum ethanol concentration in E85 to facilitate meeting ASTM minimum volatility specifications in cold

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[RRRR] A discussion of our estimate of  biodiesel use in relation to the use of petroleum-based diesel is contained in Section 1.5.4 of this RIA.

climates and when only low vapor pressure gasoline is available at terminals.[SSSS] Commenters on the ASTM proposal have stated that the current proposal to lower the minimum ethanol concentration to 68 volume percent may not be sufficient for this purpose. ASTM International may consider an additional proposal to further decrease the minimum ethanol concentration. Absent such an adjustment, a high-vapor pressure petroleum-based blendstock such as butane would need to be supplied to most petroleum terminals to produce E85 that meets minimum volatility specifications. In such a case, butane would need to be transported by tank truck from petroleum refineries to terminals and storage and blending equipment would be needed at petroleum terminals.

Automated inline butane blending systems located at terminals can be used to blend butane into gasoline before it is blended with denatured ethanol. Such systems consist of inline RVP analyzers which sample gasoline being transferred from storage tanks to loading racks where it is to be mixed with ethanol to produce E85.

The analyzers determine the RVP of the incoming gasoline stream and use this information to determine the volume of butane which must be blended with the gasoline down stream of the analyzer required to meet the volatility specification for the finished product. The analyzer, variable frequency butane pump, and supporting equipment are self-contained on a skid-mounted unit, and require at least one 60,000 gallon butane storage tank.

We estimated the number of automated inline butane blending systems, butane storage tanks, tanks trucks, railcars, trans-loading facilities, and other facility changes needed for butane blending as follows. Of the existing 1,063 terminals, two-thirds (709 terminals) are assumed to require butane in order to blend E85 that is complaint with ASTM International volatility specifications. All 709 terminals are assumed to require new butane blending equipment. Of these terminals, twenty-five percent (177) are assumed to receive butane via railcar and seventy-five percent (532) are assumed to receive butane via tank truck. Of the 177 terminals that receive butane via railcar, fifty-percent are assumed to have butane directly off-loaded to tank storage. In the case of the other fifty-percent of the terminals, butane is assumed to be trans-loaded from railcars to tank trucks for final delivery to terminals. This requires that each terminal have a skid-mounted inline butane blending system and two 60,000 gallon butane tanks. Usable tank volumes are assumed to be 51,000 gallons per tank. Tank trucks are assumed to carry 8,200 gallons of butane. Railcars are assumed to carry 31,500 gallons of butane.

Our estimates of the number of tank trucks and railcars required to deliver butane varies by control scenario (see Table 1.6-11).

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[SSSS] Minimum volatility specifications were established by ASTM to address safety and vehicle driveability considerations.

**Table 1.6-11.**
**Estimated Number of Tank Trucks and Rail Cars Needed for Shipment of Butane**

| | Number of Tank Trucks and Rail Cars Needed to Transport Butane | | |
|---|---|---|---|
| | Low Case | Medium Case | High Case |
| Tank Truck (8,200 gallons) | 2,165 | 3,280 | 5,530 |
| Railcar (31,500 gallons) | 236 | 358 | 602 |

Instead of lowering the minimum ethanol concentration of E85, some stakeholders are discussing establishing a new high-ethanol blend for use in flex-fuel vehicles. Such a fuel would have a minimum ethanol concentration that would be sufficient to allow minimum volatility specifications to be satisfied while using finished gasoline that is already available at petroleum terminals.[TTTT] E85 would continue to be marketed in addition to this new fuel for use in flex-fuel vehicles when E85 minimum volatility considerations could be satisfied.

We believe that industry will resolve the concerns over the ability to meet the minimum volatility needed for high-ethanol blends used in flex-fuel vehicles in a manner that will not necessitate the use of high-vapor pressure blendstocks in their manufacture. Nevertheless, petroleum terminals may find it advantageous to blend butane into E85 because of the low cost of butane relative to gasoline provided that the cost benefit outweighs the associated butane distribution costs.[UUUU]

### 1.6.9 Need for Additional E85 Retail Facilities

The number of additional E85 retail facilities needed to consume the volume of ethanol used under EISA varies substantially depending on the control case. As discussed in Section 1.7.1.2 of this RIA, we estimate that end-users would need to have reasonable access to E85 in 70% of the nation by 2022 under the high-ethanol scenario given our projections regarding the population of flexible fuel vehicles (FFVs) and E85 refueling frequencies.[437] Under the primary mid-ethanol scenario we estimate that reasonable access would be needed in 60% of the nation, and 40% under the low-ethanol scenario.

We define reasonable access as one in four gasoline retail facilities offering E85 in a fashion consistent with the way they currently offer gasoline. We selected one in four based on a review of the number of facilities that have been postulated to be needed to support the introduction of alternative fuels vehicles such as hydrogen and natural gas vehicles, the number of facilities that currently offer diesel fuel, and industry estimates regarding the number of E85 facilities that would be needed. One-in-five to one-in-three retail facilities has been discussed as a reasonable rule of thumb regarding the number of retail facilities needed to support the widespread introduction of alternative fuel vehicles.

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[TTTT] Such a new fuel might have a lower ethanol concentration of 60% and a maximum ethanol concentration of 85%.

[UUUU] EPA may consider reevaluating its policies regarding the blendstocks used in the manufacture of E85 to facilitate this practice.

We estimate that approximately one in three fuel retail facilities (32%) offered diesel fuel in 1999 based on our review of fuel retailer survey data.[438] The National Association of Convenience Stores (NACS) reported that in 2006, 36.6% of the respondents to their survey offered diesel fuel.[439] We believe that given that NACS members typically do not include truck stop operators (who all offer diesel fuel) that that it is most likely that the number of diesel fuel retailers has increased since 1999. Since fuel retailers make most of their money from in-store sales as opposed to fuel sales, it seems likely that more retailers recognized an opportunity to attract additional customers by offering diesel fuel since 1999. In any event, the number of diesel fuel refueling facilities available in 1999 or 2006 has not hindered the use of diesel fuel vehicles. Unlike diesel fuel vehicles that can refuel only on diesel fuel or alternative fuel vehicles that can only be fueled on the alternative fuel, flex fuel vehicles can refuel on gasoline as well as E85. Thus, we believe that fewer E85 stations should be necessary than were provided for diesel fuel.[VVVV]

At the same many time fleet operators were divesting of their in-house fueling facilities because of new environmental regulations, most retailers were installing equipment to blend mid-grade gasoline at the pump rather than store a separate mid-grade gasoline. This allowed for a significant number of retailers to begin offering diesel fuel at relatively low capital cost by converting storage tanks that had been dedicated to mid-grade gasoline storage to diesel fuel service. A number of retail facilities (40% of the total that installed diesel fuel tanks had low annual diesel throughput volumes of less than 60,000 gallons per year in 2000.[440] Only 5% of total diesel retail sales are estimated to be sold at these low-volume retailers. Given that the installation of some diesel retail facilities was not strictly driven on the expectation or realization of substantial throughput, it seems reasonable to assume that some fraction of low-volume retailers may not be absolutely necessary to ensure adequate diesel availability. Therefore, somewhat less than 32% of retail facilities might actually be needed to ensure adequate diesel fuel availability. We believe that this comparison to the number of diesel fuel retail facilities available supports our estimate that one in four retail facilities would be sufficient to provide reasonable access to E85.

The National Petroleum News (NPN) estimates that there were a total of 161,768 gasoline retail facilities in the United States in 2008.[441] We multiplied the one-in-four reasonable access assumption by the percentage of the retail market that would need to have reasonable access to E85 and the total number of retail facilities to arrive at our estimate of the number of E85 retail facilities needed under a given RFS2 control scenario. Under the high-ethanol scenario, we estimate that a total of 28,309 E85 refueling facilities would be needed. Under the primary mid-ethanol scenario, we estimate that 24,265 facilities would be needed, and that 16,177 facilities would be needed under the low-ethanol scenario.

In order to provide for sufficient E85 throughput while maintaining timely access of customers to an E85 dispenser, we estimated that all E85 retail facilities would have 3 E85 dispensers under the high-ethanol scenario.[WWWW] Under the primary mid-ethanol scenario, we estimate that half of E85 retail facilities would have a single dispenser and the other half would

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[VVVV] Particularly since we do not assume that flex-fuel vehicles would refuel on E85 all the time. A discussion of E85 refueling rates is contained in Section 1.7.1.2.4 of this RIA.

[WWWW] Each dispenser has two E85 refueling positions.

have 2 dispensers. Under the low-ethanol scenario, we estimate that all E85 retail facilities would have a single dispenser. These estimates are based on ensuring that E85 throughput per refueling position is consistent with historical data for gasoline throughput per refueling position. We believe that this approach provides an estimate consistent with ensuring that consumers have reasonable access to a E85 refueling position while providing the retailer with sufficient throughput to justify their investment in installing E85 refueling facilities.

The National Association of Convenience Stores (NACS) reports throughput per refueling position.[442] For all types of fuel dispensed, NACS reports that from 2001 through 2006, the annual throughput varied from approximately 142,000 to 164,000 gallons per refueling position. These data include reports on the sales of all fuels including premium, mid-grade, and regular gasoline, diesel fuel and other fuels. The most appropriate comparison would be made to throughput from refueling positions that dispense only regular gasoline since the use of E85 would primarily displace regular gasoline sales. However, this is not possible given that most gasoline is dispensed from blender pumps that can dispense any gasoline grade. Hence, we choose to make the comparison to throughput over dispensers that offer all gasoline grades, which may tend to underestimate the potential utilization rate of dispenser that dispenses only regular grade gasoline.

NACS reports that there is an average of 8.6 refueling positions at the retail facilities that responded to their survey. NACS reports that 36.6% of stores sold diesel fuel and 15.1% sold “other” fuels (i.e. not diesel, regular, mid-grade, or premium gasoline).[XXXX] To estimate how many refueling positions are dedicated to diesel fuel and “other” fuels, we assumed that retailers offer diesel fuel from one pump with two nozzles, and other fuels from one pump with one nozzle. By multiplying the percentage of retailers that offer diesel fuel/other fuel by the assumed refueling positions for these fuels where they are present, we arrived at an estimate of 0.9 refueling positions per facility on average dedicated to diesel fuel and other fuel. This translates to an average of 7.7 refueling positions per facility that dispenses gasoline. NACS reports that 92.7% of fuel volumes sold by respondents to their survey is gasoline (of all grades). By dividing 92.7% of the total average throughput for all fuels per facility reported by NACS by 7.7 refueling positions, we arrived at an estimate of annual gasoline throughput per nozzle of 177,000 gallons for 2003.[YYYY]

The National Ethanol Vehicle Coalition (NEVC) estimates there are currently 2,095 E85 refueling facilities.[443] However, the NEVC estimate includes E85 refueling facilities that are not open to the general public. “NEAR85” estimates that there are currently 1,293 E85 retail facilities.[444] The Near85 estimate includes only retail facilities. Based on these data, we are assuming that there are approximately 1,300 E85 retail facilities currently in service. By increasing the number of E85 retail facilities by the same proportion as the growth in ethanol use under the AEO reference from now until 2022, we estimate that 4,500 E85 refueling facilities would be in place by 2022 absent the RFS2 standards. We estimate that there would be 1,210 E85 refueling facilities under the RFS1 reference case. We arrived at this estimate by a review of historical data regarding the number of E85 retail facilities that were in place when ethanol use levels matched those under the RFS1 reference case. We assume that all E85 retail facilities

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[XXXX] In many cases, we expect that the “other” fuel is kerosene.

[YYYY] The year 2003 had the highest average throughput per refueling position over the years 2001- 2006.

under the REFS1 and AEO reference cases would have a single E85 dispenser (with 2 refueling positions).

To estimate the E85 refueling facility changes which that may be needed to reach the RFS2 volumes, we compared the changes needed to support the use of the total volume of E85 projected to be used under the 3 control scenarios to the E85 refueling facilities needed under the 2 reference cases. Our estimates of the of the E85 facility changes that will take place to reach the RFS2 volumes are contained in Tables 1.6-12 and 1.6-13

**Table 1.6-12.**
**Additional E85 Retail Facilities Needed by 2022 to Reach the RFS2 Volumes Relative to the RFS1 Reference Case**

| | Low-Ethanol Scenario | Mid-Ethanol Scenario | High-Ethanol Scenario |
|---|---|---|---|
| New E85 Installation with 1 Dispenser | 15,000 | 10,900 | 0 |
| New E85 Installation with 2 Dispensers | 0 | 12,100 | 0 |
| New E85 Installation with 3 Dispensers | 0 | 0 | 27,100 |
| Addition of 2 Dispensers to Retail Facility that had 1 Dispenser | 0 | 0 | 1,200 |

**Table 1.6-13.**
**Additional E85 Retail Facilities Needed by 2022 to Reach the RFS2 Volumes Relative to the AEO Reference Case**

| | Low-Ethanol Scenario | Mid-Ethanol Scenario | High-Ethanol Scenario |
|---|---|---|---|
| New E85 Installation with 1 Dispenser | 11,700 | 7,600 | 0 |
| New E85 Installation with 2 Dispensers | 0 | 12,100 | 0 |
| New E85 Installation with 3 Dispensers | 0 | 0 | 23,800 |
| Addition of 2 Dispensers to Retail Facility that had 1 Dispenser | 0 | 0 | 4,500 |

On average, approximately 1,520 additional E85 facilities will be needed each year from 2010 through 2022 under our primary scenario relative to the AEO reference case. Under the high and low-ethanol scenarios, an additional 1,820 and 900 E85 retail facilities per year would be needed respectively. Under the high-ethanol scenario, 4,500 facilities would also need to be upgraded to provide 3 E85 dispensers rather than a single dispenser. Under the high ethanol case and to a lesser extent under the primary case, this represents an aggressive timeline for the addition of new E85 facilities given that the small number of E85 retail facilities in service today. Nevertheless, we believe the addition of these numbers of new E85 facilities may be possible for the industries that manufacture and install E85 retail equipment. Underwriters Laboratories requires that E85 refueling dispenser systems must be certified as complete units.[zzzz] To date, no complete E85 dispenser systems have been certified by UL. We

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[zzzz] See http://ulstandardsinfonet.ul.com/outscope/0087A.html

understand that all the fuel dispenser components with the exception of the hoses that connect to the refueling nozzle have successfully passed the necessary testing. There does not appear to be a technical difficulty in finding hoses that can pass the required testing. Therefore, we anticipate this situation will be resolved once the demand for new E85 facilities is demonstrated. Hence, we believe that the current lack of a UL certification for complete E85 dispenser systems will not impede the installation of the additional E85 facilities that we projected will be needed.

Petroleum retailers expressed concerns about their ability to bear the cost of installing the needed E85 refueling equipment given that most retailers are small businesses and have limited capital resources. They also expressed concern regarding their ability to discount the price of E85 relative to E10 sufficiently to persuade flexible fuel vehicle owners to choose E85 given the lower energy density of ethanol. Today's rule does not contain a requirement for retailers to carry E85. We understand that retailers will only install E85 facilities if they can be assured of sufficient E85 throughput to recover their capital costs and that this could become an issue. However, if obligated parties are going to comply with the RFS2 standards, they will have to find a way to get the appropriate incentives to retailers. In addition, the projections regarding the future cost of gasoline relative to ethanol indicate that as crude oil prices rise it may be possible to price E85 more profitably. While the $3 billion total cost for E85 refueling facilities is a substantial sum under our primary E85 facility scenario, it equates to 3 cents per gallon of E85 throughput.[AAAAA] We expect that larger fuel retailers would be most likely to install new E85 refueling facilities. Therefore, the smallest retailers would not need to install E85 facilities. Government incentives are also available to help defer the cost of installing E85 retail equipment and expansions of these incentives are under consideration.[BBBBB] Given the projections regarding ethanol pricing relative to gasoline and other factors that may tend to encourage ethanol consumption, we believe that it may be possible for retailers to price E85 in such a way as to facilitate the sale of the E85 volumes that we estimate would be used to facilitate meeting the RFS2 volumes.[CCCCC]

### 1.6.10 Fuel Distribution Accommodations to Support the Introduction of E15 Should a Waiver be Granted

We evaluated the changes to the fuel distribution system that might be needed to support the introduction of E15 if a waiver is granted by EPA in order to provide the basis for a preliminary cost analysis regarding such changes. Our nation's system of gasoline fuel regulation, fuel production, fuel distribution, and fuel use is built around gasoline with ethanol concentrations limited to E10. As a result, while a waiver may legalize the use of mid-level ethanol blends under the CAA, there are a number of other actions that would have to occur to bring mid-level blends to retail. This discussion focuses on the changes which may impact the costs associated with the introduction of E15. A number of changes/accommodations would also be needed to federal, state, and local regulations.

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[AAAAA] Our estimates of the cost of the E85 retail facilities that would be needed to support the use of the volume of ethanol that we project would be used under the RFS2 standards is contained in Section 4.2 of this RIA. E85 retail costs were amortized over 15 years at a 7% cost of capital.

[BBBBB] See Section 1.7.1.2.3 of this RIA for a discussion of government incentives to install E85 retail refueling equipment.

[CCCCC] This issue is discussed in Section 1.7.1.2.5 of this RIA.

The CAA provides a 1 pound RVP waiver for ethanol blends of 10 volume percent or less. This waiver was granted at a time when ethanol use was not widespread. Thus, the environmental considerations at the time were relatively minor. Now that the nation is moving to E10 nationwide, the 1 psi waiver may have significant environmental implications for all conventional gasoline. Lacking a similar RVP waiver, a special low-RVP gasoline blendstock would be needed at terminals to allow the formulation of mid-level ethanol blends that are compliant with EPA RVP requirements. Providing such a separate gasoline blendstock would present significant logistical challenges and costs to the fuel distribution system. It should be possible for refiners to formulate a gasoline blendstock that would be suitable for manufacturing both mid-level ethanol blends and E10 at the terminal. While this would avoid the logistical problems associated with maintaining separate blendstocks, there could be additional refining costs.

Assuming that refiners develop a common gasoline blendstock for both E10 and E15, the accommodations that would be needed to the fuel distribution infrastructure to facilitate the introduction of a mid-level ethanol blend would primarily be limited to vehicle refueling facilities. Some terminal operators may need to modify their ethanol blending facilities to allow the in line blending of a mid-level ethanol blend. However, in most if not all cases this would only involve a modification to the software for the blending system to allow a mid-level as well as an E10 or E0 blend rate rather than necessitating a physical change to the system. Terminal operators would also need to provide for the receipt and storage of the greater volumes of ethanol needed to manufacture a mid-level ethanol blend.[DDDDD]

Fuel retailers would need to ensure that the equipment used to store and dispense E15 is suitable for this purpose. EPA's Office of Underground Storage Tanks (OUST) requires that underground storage tank (UST) systems must be compatible with the substance stored in the system. A number of authorities require that fuel retailers use equipment that has been certified as compatible with the fuel being sold. Such a certification is required by the Occupational Safety and Health Administration (OSHA), many local fire marshals, tank insurance and state tank fund policies, and the provisions contained in many business loan agreements.

Underwriters Laboratories (UL) is the leading safety certification organization and is often specifically referenced in regulations and insurance policies. UL stated that they have data which indicates that the use of fuel dispensers certified for up to E10 blends could dispense blends up to a maximum ethanol content of 15 volume percent without causing critical safety concerns.[EEEEE] Based on these data, UL stated that it would support a decision by Authorities who Have Jurisdiction (AHJs, e.g. state and local fire marshals) to permit equipment originally certified for up to E10 blends to be used to dispense up to 15 volume percent ethanol.[FFFFF] However, UL stated that it could not recertify equipment that was originally certified for up to

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[DDDDD] The need for additional facilities to receive, store, and blend ethanol is anticipated in any event due to the projected need for expanded use of E85 to meet the renewable fuel volume requirements under EISA.

[EEEEE] The UL announcement can be found at http://www.ul.com/newsroom/newsrel/nr021909.html

[FFFFF] The reference of up to 15 volume percent ethanol by UL does not equate to E15. Variability in the test method for ethanol content and other factors mean that in-use fuel blends with a nominal ethanol content of 15 % could at times exceed 15 volume percent.

E10 blends for a higher ethanol blend.[GGGGG] Furthermore, the UL announcement did not address underground storage systems (storage tank, piping, valves, pumps, fittings, leak detection, etc.).

Evaluations are currently underway by EPA's Office of Underground Storage Tanks (OUST) in coordination with the Department of Energy (DOE) and UL regarding the compatibility of existing UST systems to store mid-level ethanol blends. Based on this evaluation, OUST could prepare guidance to states on how facilities with UST systems that store a mid-level ethanol blend could demonstrate compliance with the EPA requirement that such systems are compatible with the substance stored in the system.[HHHHH] The Department of Energy in coordination with UL is conducting testing to evaluate the suitability of existing retail fuel dispensing equipment to accommodate a mid-level ethanol blend.[IIIII] Depending on the results of the OUST and DOE/UL efforts, the authorities referenced above may be encouraged to allow the use of certain existing equipment originally certified for E10 to handle a mid-level ethanol blend. One potential approach in lieu of requiring a UL certification might be for AHJs to require that fuel retailers have records to establish what type of equipment is present and to obtain manufacture certifications that the equipment is suitable for a mid-level ethanol blend.

Documenting the manufacturer and model number of the various components of their fuel storage and dispensing equipment may be a relatively simple undertaking for newer stations that have records readily on hand. However, for older stations that may have had multiple owners, it may be difficult to assemble a full list of their fuel handling components. For above ground components (i.e. the dispenser), a potential gap in the records could be resolved by a visual inspection. However, with respect to underground components there may no be practical way to identify certain components without breaking concrete. The most difficulty is likely to be faced in identifying the type of seals, gaskets, pipe joints, and bonding materials used by the contractors who installed the equipment.[JJJJJ] Many UST installation companies and components manufactures may have gone out of business, further complicating the process of identifying what hardware is installed and obtaining a manufacture certification of compatibility. This may tend to limit the ability to introduce a mid-level ethanol blend to newer fuel retailers and larger chain retailers who may have more complete records. However, such retailers are also likely to have a relatively high fuel sales compared to the fuel retailer population as a whole. Thus, the ability to introduce a mid-level ethanol blend at such retailers could potentially support the sale of a substantial volume of such a fuel.

If a partial waiver is granted which provides for the use of a mid-level ethanol blend in a subset of vehicles, then E10 would need to continue to be made available for use in vehicles/equipment not covered by the waiver.[KKKKK] We believe that this might be most

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[GGGGG] UL announced a separate retail dispenser certification pathway for ethanol blends up to E25 in August of 2009 (http://www.ul.com/global/eng/pages/corporate/newsroom/newsitem.jsp?n=ul-announces-new-certification-path-for-ethanol-fuel_20090810122400). This is addition to the UL certification pathways to cover up to E10 blends and to cover E85 and lesser ethanol blends.

[HHHHH] The EPA OUST requirement is located at 40 CFR Part 280.32. Enforcement of this requirement is typically delegated to the State level.

[IIIII] This is the above ground equipment commonly referred to as the fuel pump stand or fuel dispenser.

[JJJJJ] These are the UST components where there may be the most concern regarding compatibility with a mid-level ethanol blend.

[KKKKK] E0 will also be needed for use in gasoline piston engine aircraft.

practicably accomplished by switching some or all dispensers of regular gasoline at a retail facility to handle the mid-level ethanol blend.[LLLLL] The premium dispenser could continue to handle E10 (or E0) for use in legacy vehicles/equipment.[MMMMM] Some of the nonroad equipment currently requires the use of a premium grade fuel. Thus, premium gasoline would continue to be the "universal fuel" as it is today, capable of being used in any gasoline vehicle or equipment. Some retailers who have multiple regular grade storage tanks may choose to offer both an E15 and E10 regular grade in order to offer a less expensive E10 fuel to customers that do not require the use of premium but are not covered by a partial waiver. In most cases this would likely involve breaking concrete to separate tanks that are currently interconnected.

If the OUST and DOE evaluations show that current retail fuel equipment is largely compatible with a mid-level ethanol blend, it may be possible for a substantial number of retail facilities to introduce a mid-level ethanol blend at a modest cost. If some components of the above ground existing retail hardware are found to be incompatible with a mid-level ethanol blend, it may be possible for them to be replaced through normal attrition. For example the "hanging hardware" which includes the nozzle and hose from the dispenser is typically replaced every 3 to 5 years. If more extensive modifications are shown to be necessary, the costs could approach those necessary to introduce E85. If this is the case, the costs would tend to inhibit the rapid introduction of a mid-level ethanol blend. The potential costs to the fuel distribution system associated with the introduction of E15 are discussed in Section 4.2.1.1.

## 1.7 Ethanol Consumption Feasibility

### 1.7.1 Background

Over the past decade, ethanol use has grown rapidly due to oxygenated fuel requirements, MTBE bans, tax incentives, state mandates, the first federal renewable fuels standard ("RFS1"), and rising crude oil prices. Although the cost of crude has come down since reaching record levels in 2008, uncertainty surrounding pricing and the environmental implications of fossil fuels has continued to drive ethanol use.

As shown in Table 1.7-1, a record 9.5 billion gallons of ethanol were blended into U.S. gasoline in 2008 and EIA is forecasting additional growth in the years to come. According to their recently released Short-Term Energy Outlook (STEO), EIA is forecasting 0.7 million barrels of daily ethanol use in 2009, which equates to 10.7 billion gallons. The October 2009 STEO projects that total ethanol usage (domestic production plus imports) will reach 12.1 billion gallons by 2010.[445]

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[LLLLL] Commenters stated that this arrangement could encourage misfueling if the "premium grade" E10 was substantially more costly than the "regular grade" E15.

[MMMMM] The state of Oregon recently amended its requirement that all gasoline contain 10 percent ethanol to allow premium grade gasoline which does not contain ethanol to be sold for use in specified equipment/vehicles which may not be ethanol tolerant (including gasoline piston engine aircraft) http://www.leg.state.or.us/09reg/measures/hb3400.dir/hb3497.en.html

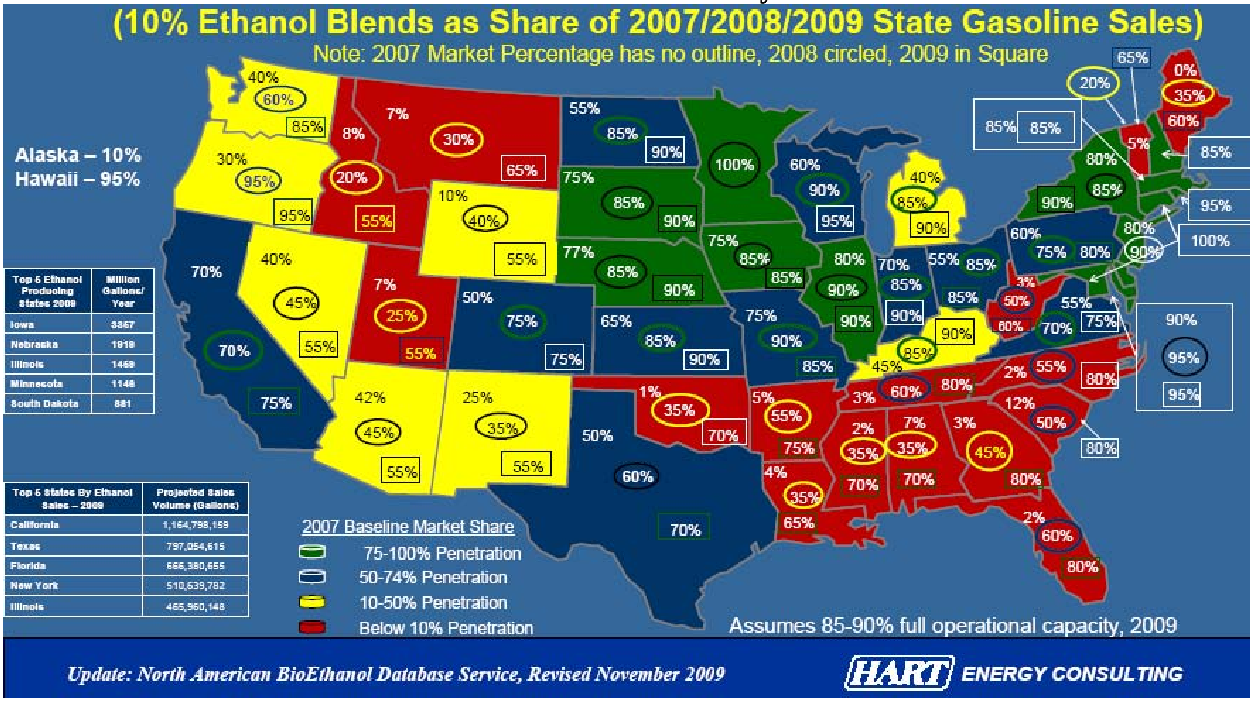
### Table 1.7-1.
### U.S. Ethanol Consumption

| | **Ethanol Usage (Bgal)** | | |
|---|---|---|---|
| **Year** | **Production** | **Net Imports**[b] | **Total**[a] |
| 1999 | 1.4 | 0.0 | **1.4** |
| 2000 | 1.6 | 0.0 | **1.6** |
| 2001 | 1.7 | 0.0 | **1.7** |
| 2002 | 2.0 | 0.0 | **2.0** |
| 2003 | 2.7 | 0.0 | **2.8** |
| 2004 | 3.3 | 0.1 | **3.5** |
| 2005 | 3.8 | 0.1 | **4.0** |
| 2006 | 4.6 | 0.7 | **5.3** |
| 2007 | 6.3 | 0.4 | **6.7** |
| 2008 | 9.0 | 0.5 | **9.5** |

[a] EIA Monthly Energy Review September 2009 (Table 10.2)
bEIA website (http://tonto.eia.doe.gov/dnav/pet/hist/mfeimus1a.htm)

The National Petrochemical and Refiners Association (NPRA) estimates that ethanol is currently blended into about 75 percent of all gasoline sold in the United States.[446] The vast majority is blended as E10 or 10 volume percent ethanol, although a small amount is blended as E85 for use in flexible fuel vehicles (FFVs). California, the largest U.S. consumer of gasoline is yet to reach 100% E10 saturation. Historically, the state has only blended ethanol into gasoline at 5.7 vol%, limited by its Predictive Model blending constraints. However, California has since adjusted its model and effective January 1, 2010, ethanol blending is expected to increase to 10%.[NNNNN] A publication by Hart Energy Consulting estimating ethanol penetration by state is provided in Figure 1.7-1.[447]

**Figure 1.7-1.**
**E10 Market Penetration by State**



(10% Ethanol Blends as Share of 2007/2008/2009 State Gasoline Sales)

Note: 2007 Market Percentage has no outline, 2008 circled, 2009 in Square

Alaska – 10%
Hawaii – 95%

| Top 5 Ethanol Producing States 2009 | Million Gallons/ Year |
|---|---|
| Iowa | 3367 |
| Nebraska | 1919 |
| Illinois | 1459 |
| Minnesota | 1148 |
| South Dakota | 881 |

| Top 5 States By Ethanol Sales – 2009 | Projected Sales Volume (Gallons) |
|---|---|
| California | 1,164,798,159 |
| Texas | 797,054,615 |
| Florida | 666,380,655 |
| New York | 510,639,782 |
| Illinois | 465,960,148 |

2007 Baseline Market Share
- 🟩 75-100% Penetration
- 🟦 50-74% Penetration
- 🟨 10-50% Penetration
- 🟥 Below 10% Penetration

Assumes 85-90% full operational capacity, 2009

*Update: North American BioEthanol Database Service, Revised November 2009*

HART ENERGY CONSULTING

Complete saturation of the gasoline market with E10 is referred to as the ethanol "blend wall." The height of the blend wall in any given year is directly related to gasoline demand. In AEO 2009, EIA projects that gasoline energy demand will peak around 2013 and then start to taper off due to vehicle fuel economy improvements. As shown below in Figure 1.7-2, not only is EIA forecasting a flattening of gasoline energy demand in the future due to vehicle improvements, AEO 2009 also shows an additional decline due to the recent economic downturn. This is a considerably different projection of the future than EIA made in their prior forecasts. Although we have presented AEO 2008 and AEO 2007 for illustrative purposes, the final release of AEO 2009 (April 2009 – ARRA Update) is the basis for all energy and ethanol consumption calculations utilized in this analysis.

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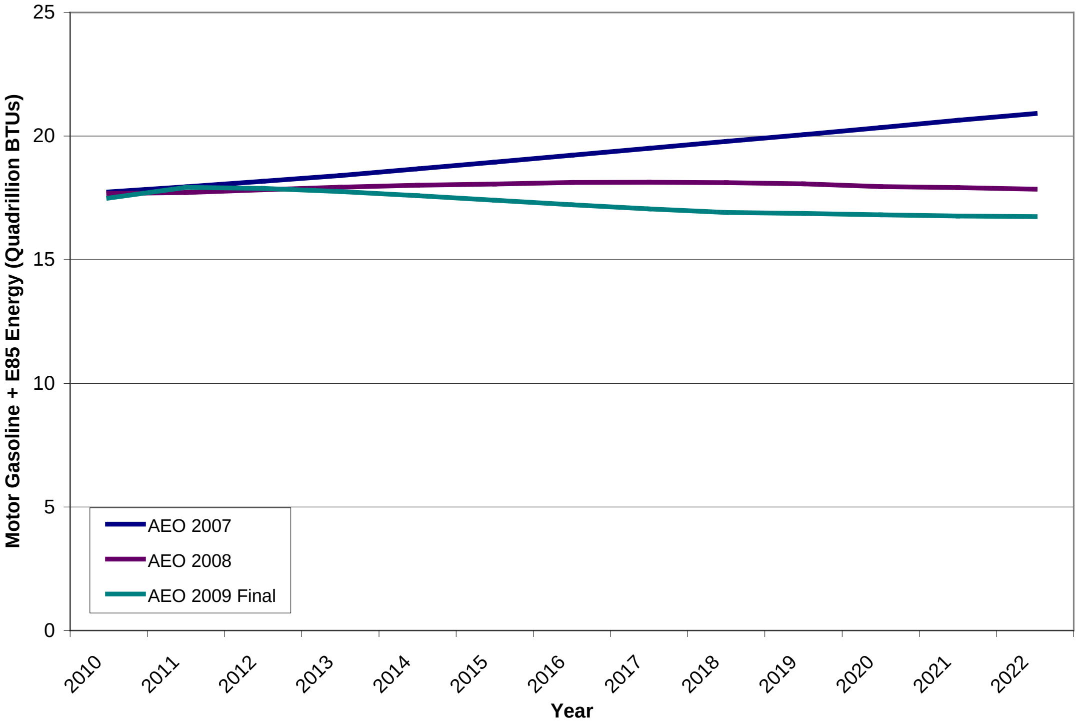
**Figure 1.7-2.**
**Projected Gasoline Energy Demand**[448]



Based on the gasoline demand projections in AEO 2009, the maximum amount of ethanol that can be blended into gasoline as E10 will be around 14-15 billion gallons, depending on the year (refer ahead to Figure 1.7-3). There are many challenges associated with getting beyond the ethanol blend wall and consuming more than 14-15 billion gallons including rapid growth in FFV/E85 infrastructure, problems with meeting ASTM specs, testing and potential approval of mid-level blends, etc. As such, as discussed in Sections 1.4.3 and 1.5.3, a growing number of companies are investigating non-ethanol biofuels (e.g., cellulose-based diesel, gasoline, etc.) as a mechanism for meeting the cellulosic biofuel standard. The benefit of synthetic hydrocarbon fuels is that there is virtually no blend wall issue, they are fungible with existing fuel infrastructure and they can be priced at parity with petroleum at retail. In many ways, they are essentially drop-in replacements for gasoline and diesel. However, like all second-generation biofuels, there are technological and financial hurdles that need to be overcome before biomass-based synthetic hydrocarbon fuels can be brought to market.

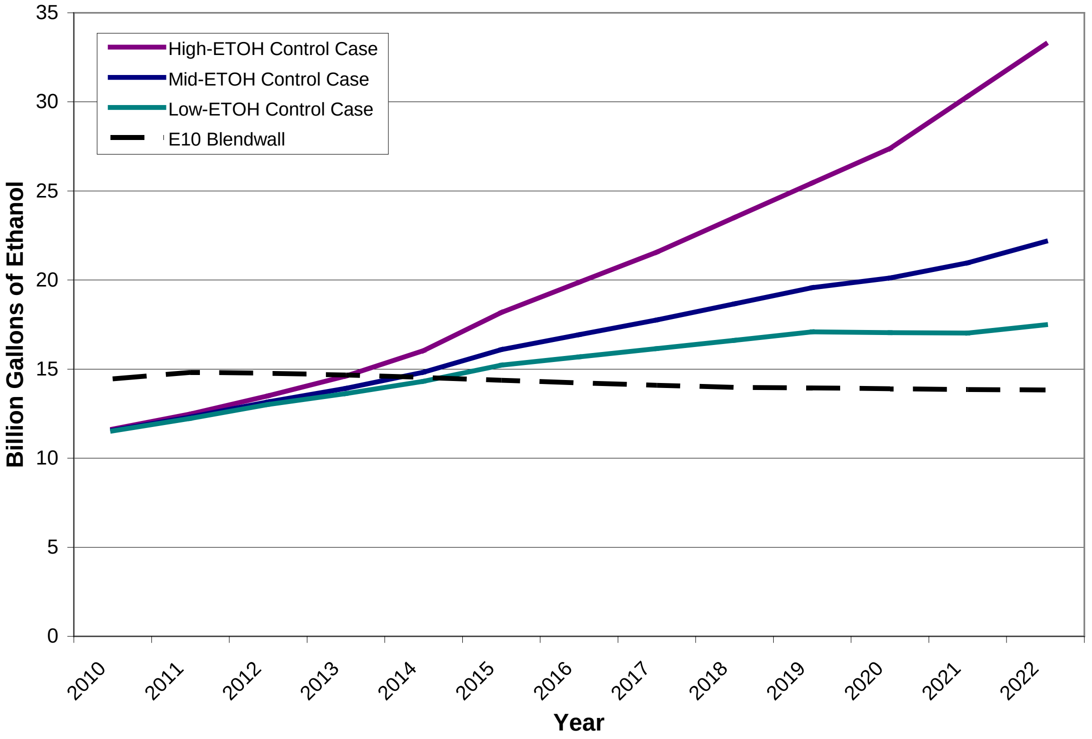
These factors make it difficult to project the mix of renewable fuels types that will be used in the future to meet the RFS2 standards. To address the uncertainty of which fuels will be used, we have analyzed three control cases with varying levels of ethanol as part of this final rule. As shown below in Table 1.7.2, total ethanol usage (corn, imported and cellulosic) could range from 17.5 to 33.2 billion gallons in 2022.

**Table 1.7-2.**
**Potential Ethanol Usage Scenarios Under RFS2**

| **Scenario** | **2022 Total Ethanol Use** |
|---|---:|
| RFS1 Reference Case | 7.1 |
| AEO 2007 Reference Case | 13.2 |
| Low-ETOH Control Case | 17.5 |
| **Mid-ETOH Control Case (Primary)** | **22.2** |
| High-ETOH Control Case | 33.2 |

Under the primary control case, ethanol consumption will need to be about three times higher than RFS1 levels, more than twice as much as today's levels, and 9 billion gallons higher than the ethanol consumption predicted to occur in 2022 absent RFS2 (according to AEO 2007). A summary of the projected ramp up in ethanol usage in each of these three cases compared to the blend wall is provided in Figure 1.7-3.  For more information on how the control case volumes were derived, refer to Section 1.2 of the RIA.

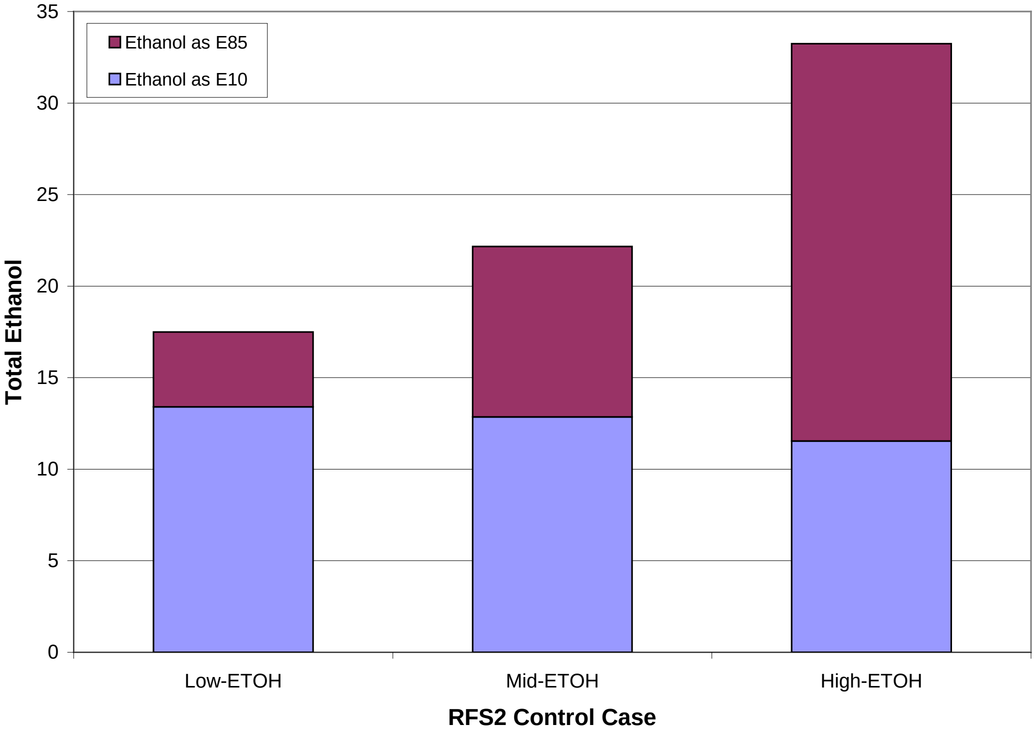
**Figure 1.7-3.**
**Projected Increase in Ethanol Under RFS2**



As shown above in Table 1.7-2, all three ethanol usage scenarios modeled require the nation to get beyond the E10 blend wall. As expected, the more aggressive the ethanol usage, the sooner the nation will hit the blend wall. As shown above, the nation is expected to hit the blend wall in 2013 under our high-ethanol control case, in 2014 under our primary mid-ethanol control case and closer to 2015 under our low-ethanol control case. Regardless, to meet today's RFS2 requirements using increased volumes of ethanol we are going to need to see growth in FFV and E85 infrastructure and increases in FFV E85 refueling rates (consideration of mid-level blends is discussed below in Section 1.7.6 below). However, the amount of change needed is proportional to the amount of ethanol we rely on versus other renewable fuels. As expected, the low-ethanol case would require only moderate changes in FFV/E85 infrastructure and refueling whereas the high-ethanol case would require very dramatic changes and likely a mandate.

Once the nation gets past the blend wall, more ethanol will need to be blended as E85 and less as E10. FFV owners who were formerly refueling on E10 will need to start filling up on E85. As shown in Figure 1.7-4, under our primary mid-ethanol control case, we project that 12.9 billion gallons of ethanol would be blended as E10 and 9.3 billion gallons would be blended as E85 to reach the 22.2 billion gallons in 2022.

**Figure 1.7-4.**
**Ethanol by Blend in 2022**



In the subsections that follow, we will present the FFV and E85 infrastructure assumptions made for the final regulatory impact analysis and the corresponding FFV E85 refueling rates that would be required to reach the ethanol volumes described above. We will also discuss some of the retail and other changes that might be needed to encourage E85 usage.

It is possible that conventional gasoline (E0) could co-exist with E10 and E85 for some time. However, for analysis purposes, we have assumed that E10 would replace E0 as expeditiously as possible and that all subsequent ethanol growth would come from E85. Furthermore, we assumed that no ethanol consumption would come from the mid-level ethanol blends (E15 or E20) since they are not currently approved for use in non-FFVs. However, in light of the Growth Energy waiver request[449], we discuss how approval of E15 for use in conventional vehicles could help the nation postpone the blend wall in Section 1.7.6.

## 1.7.2 Projected Growth in Flexible Fuel Vehicles

Over the years there have been several policy attempts to increase FFV sales including Corporate Average Fuel Economy (CAFE) credits[OOOOO] and government fleet alternative-fuel

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[OOOOO] Under the CAFE program, the production of FFVs provides credits toward meeting the required standards. However, the EPCA incrementally phases out these credits through MY 2019, after which they are no longer available to help demonstrate CAFE compliance. EPA recently proposed similar FFV credits as part of their Rulemaking to Establish Light-Duty Vehicle GHG Emission Standards and Corporate Average Fuel Economy vehicle requirements. As a result, there are an estimated 8 million FFVs on the road today, up from just over 7 million in 2008.[PPPPP,450] While this is not insignificant in terms of growth, FFVs continue to make up less than 4 percent of the total gasoline vehicle fleet.

According to EPA certification data, over one million FFVs were sold in both 2008 and 2009. Despite the recession and current state of the auto industry, automakers are incorporating more and more FFVs into their light-duty production plans. While the FFV system (i.e., fuel tank, sensor, delivery system, etc.) used to be an option on some vehicles, most are moving in the direction of converting entire product lines over to E85-capable systems. Still, the number of FFVs that will be manufactured and purchased in future years is uncertain.

To measure the impacts of increased volumes of renewable fuel, we considered three different FFV production scenarios that might correspond to the three biofuel control cases analyzed for the final rule. For all three cases, we assumed that total light-duty vehicle sales would follow AEO 2009 trends. The latest EIA report suggests lower than average sales in 2008-2013 (less than 16 million vehicles per year) before rebounding and growing to over 17 million vehicles by 2019 as shown below in Figure 1.7-5.[451] These vehicle projections are consistent with EPA's recently proposed Light-Duty Vehicle GHG Rule.[452]

We also applied the AEO 2009 projected car/truck sales split adjusted for NHTSA's new car definition beginning in 2011.[QQQQQ] Accordingly, by 2022, cars are expected to comprise over 70% of new light-duty vehicle sales. With respect to in-use vehicle stock, we relied on historical car/truck sales reported by DOE's Energy Efficiency and Renewable Energy (EERE) combined with vehicle survival rates taken from the proposed Light-Duty Vehicle GHG Rule.[453,454]

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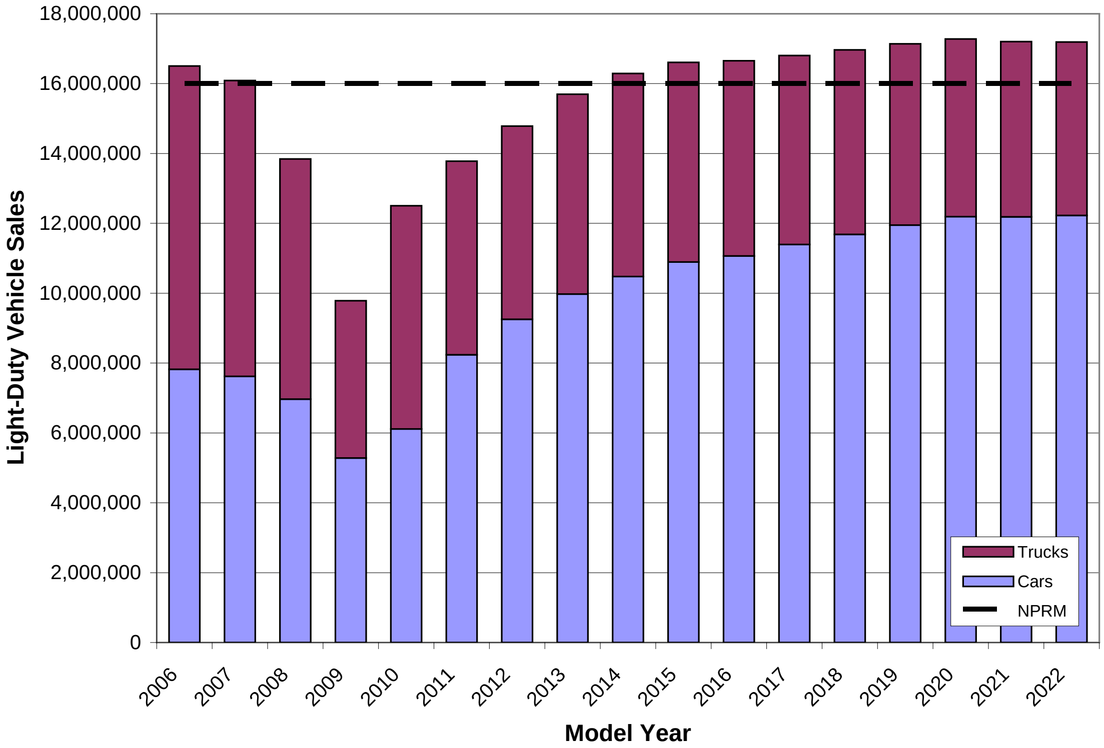
Standards (74 FR 49454 September 28, 2009). Under the proposed program, FFV credits would remain available for 2016 and later model years, but the credits would be based on demonstrated E85 usage.

[PPPPP] FFV sales based on DOE's Energy Efficiency and Renewable Energy (EERE) for 1998-2005 and EPA's vehicle certification data for 2006-2008. In-use FFV estimates based on vehicle survival rates taken from EPA's proposed Light-Duty Vehicle GHG Rule.

[QQQQQ] According to NHTSA's Final Rule on 2011 MY Vehicles (74 FR 14196 March 30, 2009), starting in MY 2011, 2WD versions of SUVs are no longer classified as off-highway capable light trucks under 49 CFR § 523.5(b), simply because the SUV also comes in a 4WD version. Based on an estimate used in EPA's Proposed Light-Duty Vehicle GHG Rule, approximately 22% of the forecasted AEO 2009 light-duty truck sales are cars based on the new NHTSA definition.

**Figure 1.7-5.**
**Assumed Light Duty Vehicle Production**



Although we assumed that total vehicle and car/truck sales would be the same in all three cases, we assumed varying levels of FFV production. For our low-ethanol control case, we assumed steady FFV growth according to AEO 2009 predictions.[455] For our primary mid-ethanol control case, we assumed increased FFV sales under the presumption that GM, Ford and Chrysler (referred to hereafter as the "Detroit 3") would follow through with their commitment to produce 50% FFVs by 2012. Despite the current state of the economy and the hardships facing the auto industry, the Detroit 3 appear to still moving forward with their voluntary FFV commitment.[456] And finally, for our high-ethanol control case, we assumed a theoretical 80% FFV mandate based on the Open Fuel Standard Act of 2009 that was reintroduced in Congress on March 12, 2009.[457] Based on reduced vehicle sales and gasoline demand, we believe an FFV mandate would be the only viable means for consuming the 32.2 billion gallons of ethanol in 2022 required under the high-ethanol control case.

For the two reference cases, we assumed more modest, business-as-usual FFV sales. For the RFS1 reference case, we assumed that automakers would continue to make about 8% of all light-duty vehicles FFVs (current 2008 marketshare based on EPA certification data). For the AEO 2007 reference case, we assumed FFV growth according to EIA's AEO 2007.[458] The annual FFV sales assumptions for our three control cases and two reference cases are presented below in Table 1.7-3. More information on FFV cost and assumptions made with respect to our primary mid-ethanol control case is presented below.

We estimate that the cost to produce FFVs could be anywhere from $50 to $100 per vehicle, depending on the vehicle and how many FFV-capable systems the automaker is producing. Current estimates suggest that the per-FFV cost could easily be as high as $100.[RRRRR,459] However, in the event of a hypothetical mandate, automakers would likely find a more economical way to mass produce the necessary ethanol-compatible fuel tanks, sensors, etc. As such, we assigned higher per-vehicle FFV production costs in the low-ethanol control case and lower production costs in the high-ethanol case. For more on this rationale and the resulting FFV production costs, refer to Section 4.2 of the RIA.

**Table 1.7-3.**
**Annual FFV Sales Assumptions**

| | **Reference Cases** | | **Control Case FFV Production** | | |
|---|---|---|---|---|---|
| | **RFS1** Based on Today's Marketshare | **AEO 2007** Based on AEO 2007 Predictions | **Low-ETOH** Based on AEO 2009 Predictions | **Mid-ETOH** Based on 50% Domestic 3 Commitment | **High-ETOH** Based on OFS Mandate in Congress |
| **2010** | 983,267 | 1,669,998 | 1,253,426 | 1,848,835 | 3,617,298 |
| **2011** | 1,083,940 | 1,746,847 | 1,598,610 | 2,661,252 | 5,439,471 |
| **2012** | 1,162,875 | 1,768,321 | 1,903,862 | 3,523,548 | 7,393,103 |
| **2013** | 1,234,554 | 1,795,684 | 2,251,284 | 3,740,737 | 9,418,573 |
| **2014** | 1,281,162 | 1,826,871 | 2,523,575 | 3,881,960 | 11,403,172 |
| **2015** | 1,306,173 | 1,817,706 | 2,693,557 | 3,957,744 | 13,286,614 |
| **2016** | 1,309,814 | 1,817,699 | 2,761,794 | 3,968,776 | 13,323,649 |
| **2017** | 1,321,421 | 1,826,073 | 2,804,322 | 4,003,948 | 13,441,727 |
| **2018** | 1,334,395 | 1,834,957 | 2,929,336 | 4,043,259 | 13,573,697 |
| **2019** | 1,348,016 | 1,855,352 | 2,825,574 | 4,084,529 | 13,712,247 |
| **2020** | 1,358,903 | 1,899,794 | 2,771,285 | 4,117,519 | 13,822,998 |
| **2021** | 1,352,943 | 1,913,799 | 2,669,883 | 4,099,459 | 13,762,369 |
| **2022** | 1,351,996 | 1,913,938 | 2,607,584 | 4,096,590 | 13,752,738 |

For our primary mid-ethanol control case, we assumed that the Detroit 3 would continue to comprise 45% of total light-duty vehicle sales – 2008 production levels less Hummer, Landrover, Jaguar, Saab, Saturn, and Volvo (brands that were recently or are in the process of being sold off). We assumed that domestic automakers would continue to dominate truck sales and car sales would gradually increase to allow the Detroit 3 to continue to maintain 45% marketshare in future years. With respect to FFV sales, we assumed that the Detroit 3 would follow through with their FFV commitment and increase FFV production from 16% of total sales in 2008 to 50% of total sales in 2012. With respect to vehicle type, we assumed that about two-thirds of the Detroit 3's FFV sales would be trucks – based on historical sales and 2009 MY offerings.

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[RRRRR] According to DOE and others, conventional gasoline engines need to be slightly modified (at an additional cost of about $100) to handle higher blends of ethanol.

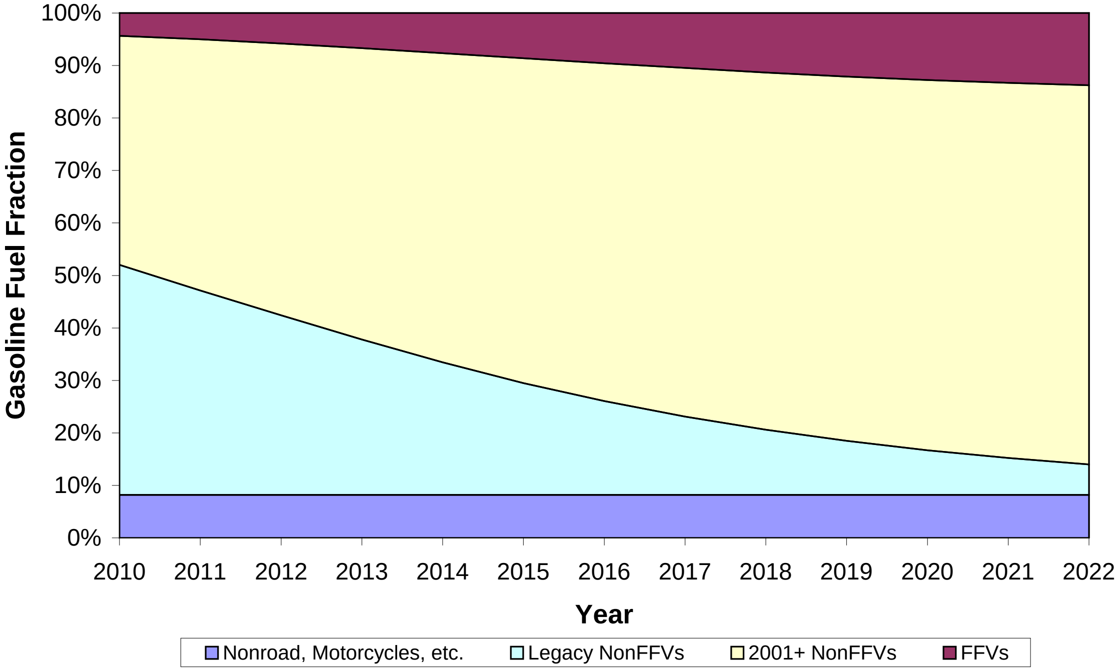
We assumed that non-domestic automakers would continue to maintain 55% marketshare in 2009 and beyond (based on adjusted 2008 production levels). Although non-domestic automakers have not made any official FFV production commitments, Nissan, Toyota, Mercedes, Izuzu, and Mazda all included at least one flexible fuel vehicle in their 2009 model year offerings.[460] We do not currently anticipate that the non-domestic automakers will follow through with an FFV commitment. However, it seems reasonable that we could expect a small amount of FFV growth in the future. As such, for our primary mid-ethanol control case, we assumed that non-domestic FFV production would grow from 1% in 2008 to 2% in 2009 and future years based on current FFV offerings. With respect to FFV vehicle type, we assumed about equal car and truck FFV sales (52% and 48%, respectively) based on 2008 sales.

Under our primary mid-ethanol scenario, as shown in Table 1.7-3, Detroit 3 and non-domestic FFV sales amount to just over 4 million per year in 2017 and beyond. This is less aggressive than the assumptions made in the NPRM. At that time, we were expecting more cellulosic ethanol which could justify higher FFV production assumptions. We assumed that not only would the Detroit 3 fulfill their 50% by 2012 FFV production commitment, non-domestic automakers might follow suit and produce 25% FFV in 2017 and beyond. We also assumed that annual light-duty vehicle sales would continue around the historical 16 million vehicle mark resulting in 6 million FFVs in 2017 and beyond.

Based on our revised vehicle/FFV production assumptions coupled with vehicle survival rates, VMT and fuel economy estimates applied in the recently proposed Light-Duty Vehicle GHG Rule, we estimate that the maximum percentage of fuel (gasoline/ethanol mix) that could feasibly be consumed by FFVs in 2022 would be about 20% under our mid-ethanol control case. Under our low-ethanol control, the 2022 fuel fraction was estimated at 14%. And under the high-ethanol control case, with the FFV mandate, the fuel fraction was 56% in 2022. A summary of the FFV fuel fraction over time for each of these scenarios is presented in Figures 1.7-6 through 1.7-8.

## Figure 1.7-6

## Low-ETOH / Low-FFV Fuel Fraction



## Figure 1.7-7

## Mid-ETOH / Mid-FFV Fuel Fraction

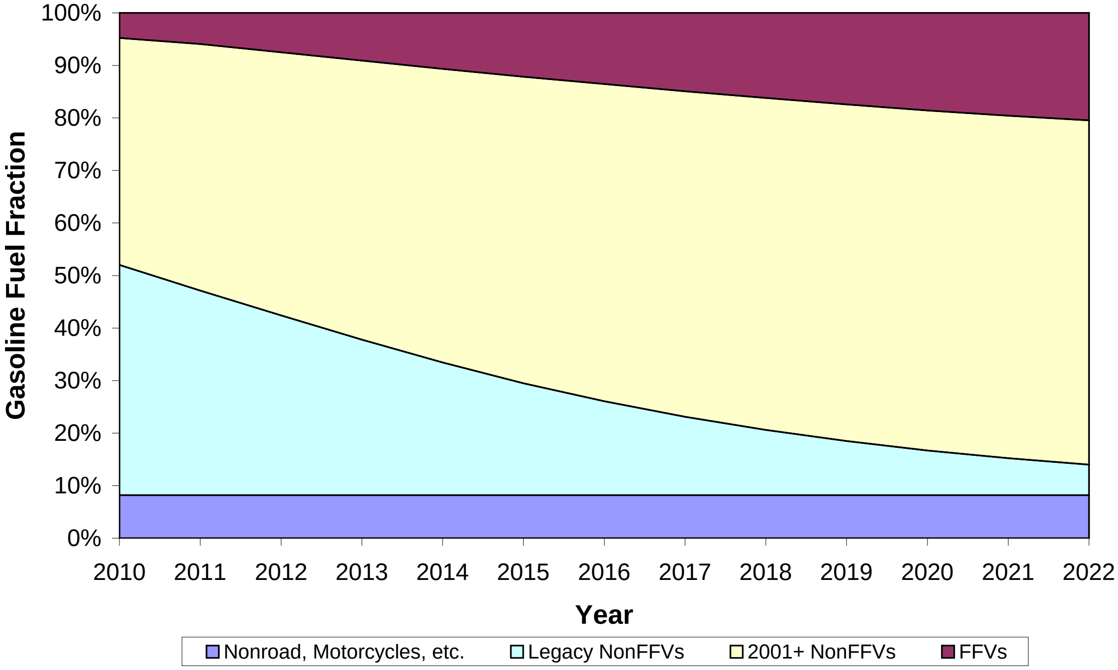
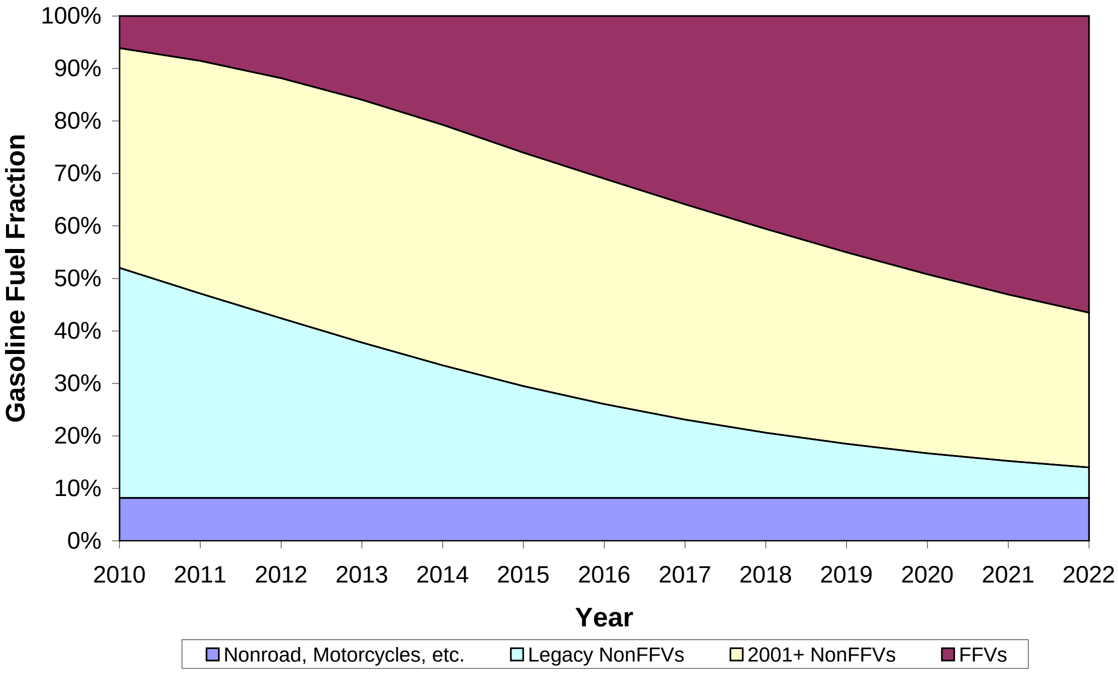


**Figure 1.7-8**

**High-ETOH / High-FFV Fuel Fraction**



As shown above, we split the non-FFV fuel fraction into multiple categories to help determine the number of engines/vehicles that might be capable of handling E15 in the event of a waiver. The basis for these assumptions and more information on the data sources is presented in Section 1.7.6.

### 1.7.3 Projected Growth in E85 Access

According to the National Ethanol Vehicle Coalition (NEVC), there are currently 2,100 gas stations offering E85 in 44 states plus the District of Columbia.[461] While this represents significant industry growth, it still only translates to 1.3% of U.S. retail stations nationwide carrying the fuel.[SSSSS] As a result, most FFV owners clearly do not have reasonable access to E85. For our FFV/E85 analysis, we have defined "reasonable access" as one-in-four pumps offering E85 in a given area.[TTTTT] Accordingly, just over 5% of the nation currently has reasonable access to E85, up from 4% in 2008 (based on a mid-year NEVC pump estimate).[UUUUU]

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[SSSSS] Based on National Petroleum News gasoline station estimate of 161,768 in 2008.

[TTTTT] For a more detailed discussion on how we derived our one-in-four reasonable access assumption, refer to Section 1.6 of the RIA. For the distribution cost implications as well as the cost impacts of assuming reasonable access is greater than one-in-four pumps, refer to Section 4.2 of the RIA.

[UUUUU] Computed as percent of stations with E85 (2,101/161,768 as of November 2009 or 1,733/161,768 as of August 2008) divided by 25% (one-in-four stations).

There are a number of states promoting E85 usage by offering FFV/E85 awareness programs and/or retail pump incentives. A growing number of states are also offering infrastructure grants to help expand E85 availability. Currently, 10 Midwest states have adopted a progressive Energy Security and Climate Stewardship Platform.[VVVVV,462] The platform includes a Regional Biofuels Promotion Plan with a goal of making E85 available at one third of all stations by 2025. In addition, the American Recovery and Reinvestment Act of 2009 (ARRA or Recovery Act) recently increased the existing federal income tax credit from $30,000 or 30% of the total cost of improvements to $100,000 or 50% of the total cost of needed alternative fuel equipment and dispensing improvements.[463]

Given the growing number of subsidies, it is clear that E85 infrastructure will continue to expand in the future. However, like FFVs, we expect that E85 station growth will be somewhat proportional to the amount of ethanol realized under the RFS2 program. As such, we analyzed three different E85 growth scenarios for the final rule that could correspond to the three different RFS2 control cases. As an upper bound for our high-ethanol control case, we maintained the 70% access assumption we applied for the NPRM. This translates to about 1:6 stations nationwide.

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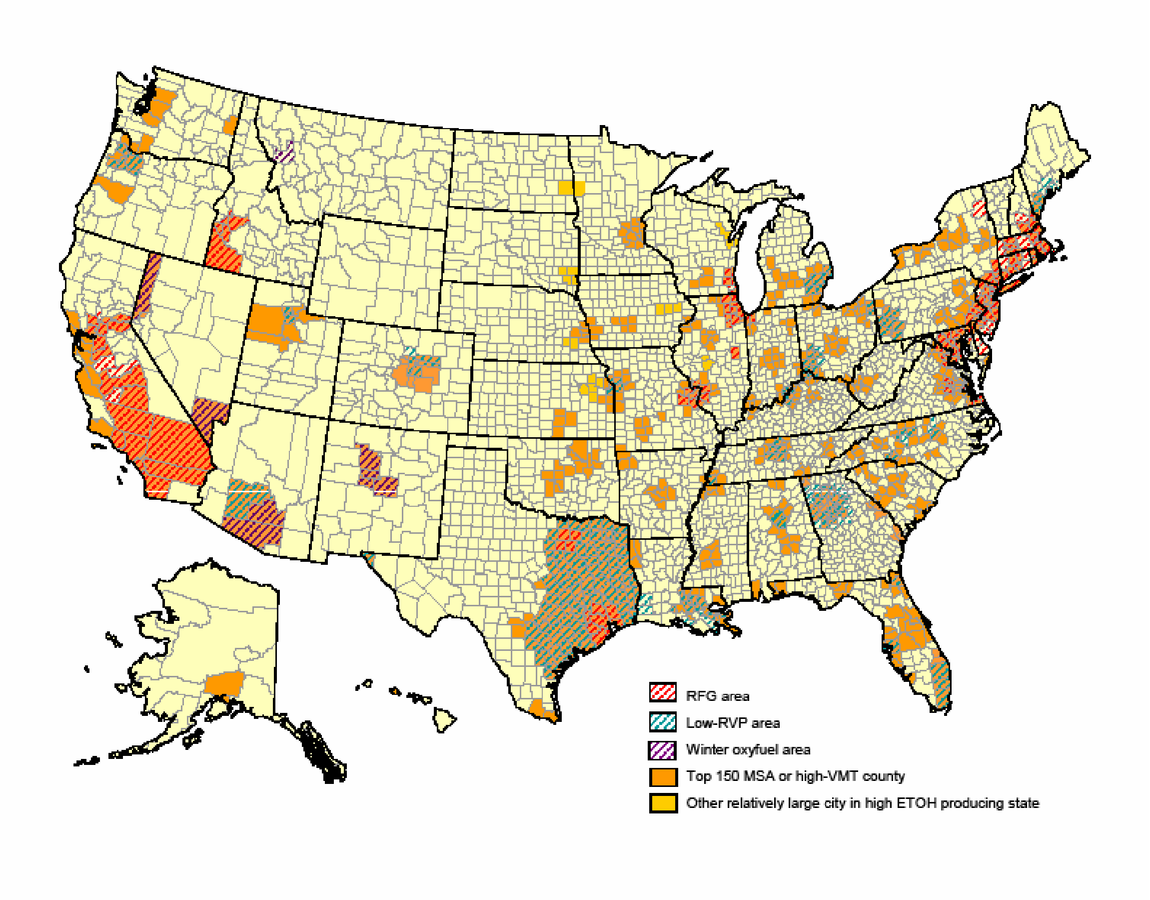
[VVVVV] The following states have adopted the plan: Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, Ohio, South Dakota and Wisconsin.

As explained in the NPRM, one way to provide 70% of the nation with reasonable 1-in-4 access would be to make it available in urban areas. For analysis purposes, we defined “urban” areas as:

- The top 150 metropolitan statistical areas according to the U.S. Census Bureau and/or counties with the highest 150 VMT projections according the EPA MOVES model.
- Federal RFG areas
- Winter oxy-fuel areas
- Summertime low-RVP areas
- Other relatively populated cities in the Midwest. Cities with populations greater than 100,000 people in states with a potential ethanol surplus in 2022.

For an illustration of the urban areas representing about 70% of the nation’s VMT, refer to Figure 1.7-9

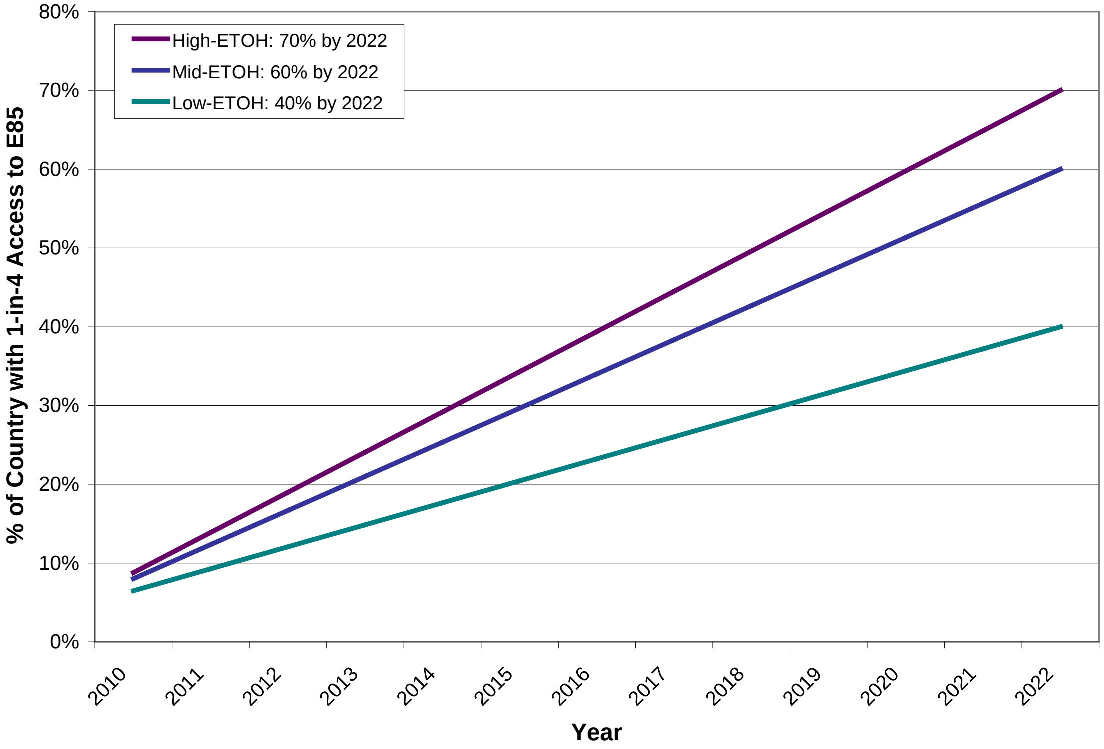
**Figure 1.7-9.**
**A Look at 70% E85 Access - Concentrating Pumps in Urban Areas**



For our other control cases we assumed access to E85 would be lower with the logic that retail stations (the majority of which are independently owned and operated and net around

$30,000 per year) would not invest in more E85 infrastructure than what was necessary to meet the RFS2 requirements. As explained in Section 4.2.1.1.9 of the RIA, the cost to install E85 could be anywhere from $131,000 to $177,000 per station depending on the configuration and number of dispensers. For our primary mid-ethanol control case we assumed reasonable access would grow from 4% in 2008 to 60% in 2022 and for our low-ethanol control case we assumed that access would only grow to 40% by 2022. As a simplifying assumption, we assumed a linear phase-in as shown below in Figure 1.7-10. As discussed in Section 1.6, we believe these E85 growth scenarios are possible based on our assessment of distribution infrastructure capabilities. For more on the number of new E85 stations compared to the reference cases and the associated cost, refer to Section 4.2.1.1.9 of the RIA.

**Figure 1.7-10.**
**Projected Growth in 1-in-4 Station Access to E85**



## 1.7.4 Required Increase in E85 Refueling Rates

As mentioned earlier, there were just over 7 million FFVs on the road in 2008. If all FFVs refueled on E85 100% of the time, this would translate to about 8.3 billion gallons of E85 use. This is based on the assumption that the average FFV in 2008 traveled about 16,500 miles and got about 19 miles per gallon of gasoline under actual in-use driving conditions.[WWWWW,464]

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[WWWWW] Fleet average VMT and MPG estimates based on modeling assumptions used in the proposed Light-Duty Vehicle GHG Rule.

The estimate also assumes is takes about 1.3 gallons of E85 for an FFV to travel the same distance as a gallon of gasoline due to the difference in energy density of the fuels.[XXXXX]

Although we computed the theoretical E85 usage potential to be around 8.3 billion gallons in 2008, according to EIA, actual E85 usage was only about 12 million gallons in 2008.[YYYYY,465] This means that, on average, FFV owners were only tapping into about 0.15% of their vehicles' E85/ethanol usage potential. Assuming only 4% of the nation had reasonable one-in-four access to E85 in 2008 (as discussed in Section 1.7.3), this equates to an estimated 4% E85 refueling frequency for those FFVs that had reasonable access to the fuel.

There are several reasons behind today's low E85 refueling frequency. For starters, many FFV owners may not know they are driving a vehicle that is capable of handling E85. As mentioned earlier, more and more automakers are starting to produce FFVs by engine/product line, e.g., all 2008 Chevy Impalas are FFVs.[466] Consequently, consumers (especially brand loyal consumers) may inadvertently buy a flexible fuel vehicle without making a conscious decision to do so. And without effective consumer awareness programs in place, these FFV owners may never think to refuel on E85. In addition, FFV owners with reasonable access to E85 and knowledge of their vehicle's E85 capabilities may still not choose to refuel on E85. They may feel inconvenienced by the increased refueling requirements. Based on its lower energy density, FFV owners will need to stop to refuel 22% more often when filling up on E85 over E10 (and 24% more often when refueling on E85 over conventional gasoline).[ZZZZZ] In addition, some FFV owners may be deterred from refueling on E85 out of fear of reduced vehicle performance or just plain unfamiliarity with the new motor vehicle fuel. However, as we move into the future, we believe the biggest determinant will be price – whether E85 is priced competitively with gasoline based on its reduced energy density (discussed in more detail below).

To comply with the RFS2 program and consume 17.5 to 33.2 billion gallons of ethanol by 2022, not only will we need more FFVs and more E85 retailers, we'll also need to see a dramatic increase in the FFV E85 refueling frequency relative to today. Based on the FFV and retail assumptions presented in Sections 1.7.2 and 1.7.3, our analysis suggests that FFV owners with reasonable access to E85 would need to refuel on it 42-70% of the time, depending on the scenario (refer to Figure 1.7-11). This is a significant increase from today's estimated 4% refueling frequency.

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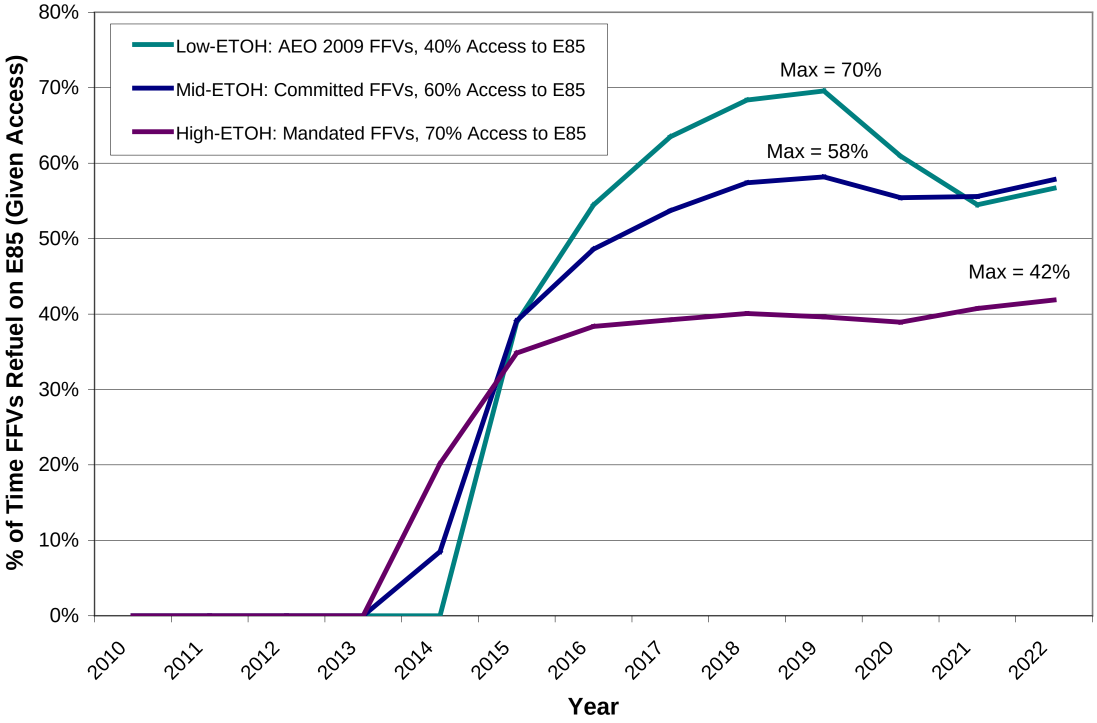
[XXXXX] Assuming E85 contains approximately 74 vol% denatured ethanol on average (77,012 BTU/gal) and 26 vol% E0 gasoline (115,000 BTU/gal) based on EIA's AEO 2009 assumption.

[YYYYY] 0.007 quadrillion BTUs of ethanol from E85 (from AEO 2009) converted into Bgal using EIA's HHV (84,262 BTU/gal) and divided by 0.74 (EIA's assumed average ethanol content of E85).

[ZZZZZ] Assuming E85 contains approximately 74 vol% denatured ethanol on average (77,012 BTU/gal) and 26 vol% E0 gasoline (115,000 BTU/gal) based on EIA's AEO 2009 assumption. For analysis purposes, E10 was assumed to contain 10 vol% denatured ethanol and 90 vol% E0 gasoline.

**Figure 1.7-11.**
**Necessary FFV E85 Refueling Rates**
**(Given 1-in-4 Access to Fuel)**



As shown above, modeling an FFV mandate and E85 station access reaching 70% by 2022, results in the lowest required FFV E85 refueling frequency (42%) for the high-ethanol control case. Similarly, the infrastructure assumptions modeled for the low-ethanol control case resulted in the highest required FFV E85 refueling frequency (70%). While this may seem counter-intuitive, the result is a product of the competing and variable modeling assumptions used. Had we elected to hold FFV production and E85 access constant for all three control cases (i.e., applied more aggressive infrastructure assumptions across the board), we would have come up with the lowest required FFV E85 refueling frequency for low-ethanol case and the highest requirements for the high-ethanol case. The computed required refueling frequency would also look more linear. However, this would mean large investments in FFV production and E85 refueling infrastructure despite low demand for E85. We figured that, at costs of up to $100 per FFV and as much as $177,000 per E85 station, the nation would not build more FFV/E85 infrastructure than what was needed to meet the RFS2 requirements Regardless, in order for any significant increase in FFV E85 refueling rates to occur, there will need to be an improvement in the current E85/gasoline price relationship.

## 1.7.5 Market Pricing of E85 Versus Gasoline

According to an online fuel price survey, E85 is currently priced almost 40 cents per gallon or about 15% lower than regular grade conventional gasoline.[467] But this is still about 30 cents per gallon higher than conventional gasoline on an energy-equivalent basis. To increase our nation's E85 refueling frequency to the levels described above, E85 needs to be priced competitively with (if not lower than) conventional gasoline based on its reduced energy content, increased time spent at the pump, and limited availability.  Overall, we estimate that E85 would need to be priced about 25% lower than E10 at retail in 2022 in order for it to make sense to consumers (as outlined below).

First, E85 needs to be priced lower than E10 based on its reduced energy density.  For our ethanol consumption analysis and this E85/gasoline price assessment, denatured ethanol was assumed to have a lower heating value of 77,012 BTU/gal based on the new 2% denaturant requirement.[AAAAAA,468] Conventional gasoline (E0) was assumed to have an average lower heating value of 115,000 BTU/gal.  E10 was assumed to contain 10 vol% denatured ethanol and 90 vol% gasoline and E85 was assumed to contain 74 vol% denatured ethanol and 26 vol% gasoline on average (based on EIA's AEO 2009 report).[469] As shown below, E85 would need to be priced about 78% lower than E10 based on its reduced energy density.

$$\frac{E85 EnergyDensity}{E10 EnergyDensity} = \frac{0.74 * 77{,}012 BTU / gal + 0.26 * 115{,}000 BTU / gal}{0.10 * 77{,}012 BTU / gal + 0.90 * 115{,}000 BTU / gal} = 78.1\%$$

In 2022, based on EIA's $116/barrel crude oil projections, wholesale gasoline (E10) is expected to be priced at $3.42/gallon.[BBBBBB] Factoring in transportation costs, taxes, and mark-up at retail (about $0.60/gallon total), gasoline can be expected to be priced at $4.02/gallon at retail in 2022.  To be cost-competitive with gasoline, E85 would have to be priced at least 78% lower than E10 at retail, or around $3.14/gallon.

In addition, we need to take the value of FFV owners' time into consideration because they could be spending 22% more time at the pump if they are refueling exclusively on E85.  In the U.S., a person's time is currently valued at around $30 per hour.  This value of time (VOT) estimate was based on an average of values identified in a review of economics literature and is consistent with 2005 Brownstone and Small VOT estimates.[470] Adjusting the 2005 VOT estimate to 2007 dollars, yields a $31.61 per hour estimate. Assuming it takes about six minutes for a 15-gallon refill, E85 needs to be priced an additional $0.05 per gallon less than E10

Finally, we accounted for the fact that, as an alternative fuel, it is unlikely that E85 will ever be available nationwide.  As mentioned above, the greatest access we anticipate FFV owners will have to E85, is one-in-four stations offering the fuel.  And that will likely only be in select areas of the country.  And unlike diesel fuel, FFV owners are not required to fill up on it. So in order to get consumers to want to refuel on E85 over gasoline, there needs to be an additional price incentive at the pump according to a 1997 Oakridge National Lab report.[CCCCCC,471] As shown below in Figure 1.7-12, if an alternative fuel is only available at 25%

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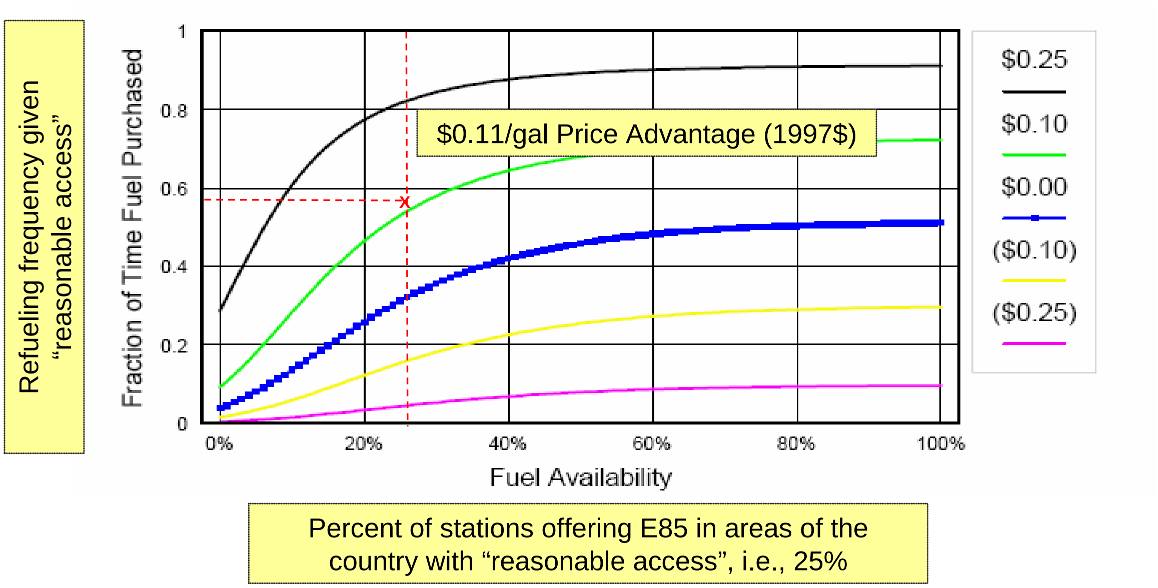
[AAAAAA] The 2008 Farm Bill1 contained a provision that stipulates the full value of the Volumetric Ethanol Excise Tax Credit (VEETC) is only available to blenders when using fuel ethanol denatured at a maximum of 2%.

[BBBBBB] Refer to Table 4.4-9 in Section 4.4 of the RIA.

[CCCCCC] Although the 1997 David Greene study was based on asking consumers about a hypothetical fuel that "works just as well as gasoline", we assumed that Figure 6 from the report (pictured) could also be used to determine the retail price incentive given to E85 to account for its limited availability .  As explained in the of stations and you want people to refuel on it about 58% of the time in 2022 (as is, under our primary mid-ethanol control case), it needs to be given an $0.11/gallon price advantage (1997$). Inflating the 1997 David Greene estimate to 2007 dollars, E85 would need to be priced an additional 14 cents per gallon lower than E10.

**Figure 1.7-12.**
**Required Price Incentive for Alternative Fuels with Limited Availability**



Refueling frequency given "reasonable access"

$0.11/gal Price Advantage (1997$)

Percent of stations offering E85 in areas of the country with "reasonable access", i.e., 25%

Overall, our retail price analysis suggests that E85 would need to be priced around $2.95 per gallon ($3.14/gal - $0.05/gal - $0.14/gal) in order for it to be competitive with $4.02 gasoline in 2022. Essentially, E85 would need to be priced at least 25% lower than gasoline at retail outlets in order for consumers to want to choose it regularly.

However, ultimately it comes down to what refiners are willing to pay for ethanol blended as E85. The more ethanol you try to blend as E85, the more devalued ethanol becomes as a gasoline blendstock. Changes to state and Federal excise tax structures could help promote ethanol blending as E85. But for the most past, as long as crude oil prices remain high (as projected by AEO 2009), it should look attractive to refiners as a blendstock. Based on our retail cost calculations, summarized in Figure 1.7-13 below, ethanol would have to be priced at $1.97/gallon in order for it to be attractive to refiners for E85 blending in 2022.

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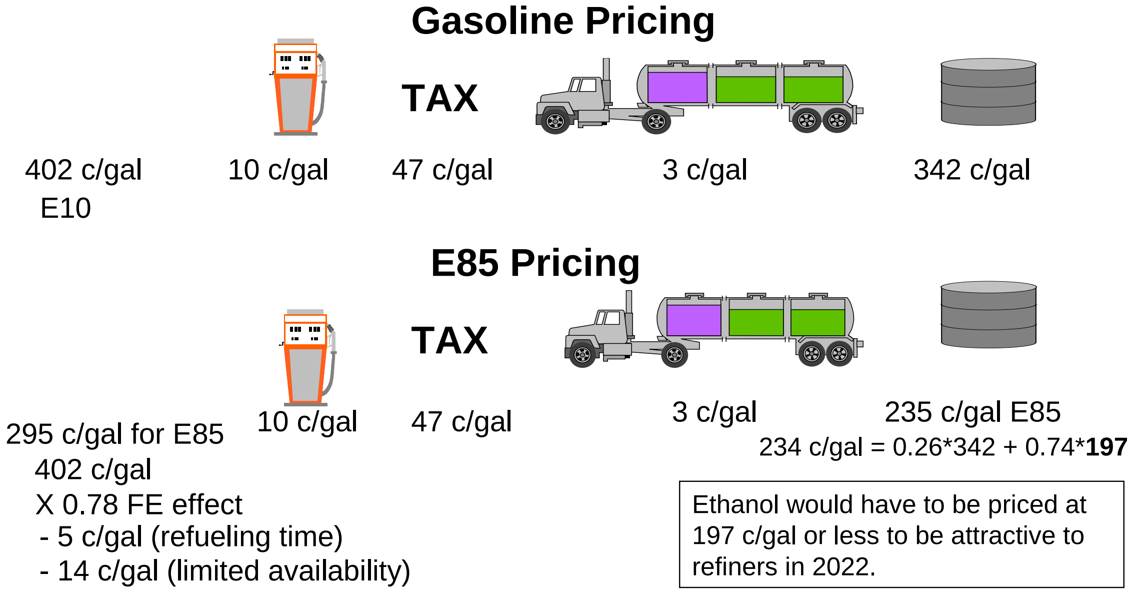
preceding text, this was in addition to the incentives assigned to E85 to account for its reduced energy density and additional time spent at the pump.

**Figure 1.7-13.**
**Required Ethanol Pricing Needed in 2022 to Encourage E85 Blending**



According to the DTN Ethanol Center, the current rack price for ethanol is around \$2.20/gallon.[472] However, as explained in Section 4.4 of the RIA, we project the average ethanol delivered price (volume-weighted average production cost of corn, cellulosic and imported ethanol plus distribution) will come down to around \$1.67/gallon in 2022 under our mid-ethanol primary control case.[DDDDDD] Therefore, while gasoline refiners and markets will always have a greater profit margin selling ethanol in low-level blends to consumers based on volume, they should be able to maintain a profit selling it as E85 in the future.

### 1.7.6 Consideration of >10% Ethanol Blends

On March 6, 2009, Growth Energy and 54 ethanol manufacturers submitted an application for a waiver of the prohibition of the introduction into commerce of certain fuels and fuel additives set forth in section 211(f) of the Act. This application seeks a waiver for ethanol-gasoline blends of up to 15 percent ethanol by volume.[473] On April 21, 2009, EPA issued a Federal Register notice announcing receipt of the Growth Energy waiver application and soliciting comment on all aspects of it.[474] On May 20, 2009, EPA issued an additional Federal Register notice extending the public comment period by an additional 60 days.[475] The comment period ended on July 20, 2009, and EPA is now evaluating the waiver application and considering the comments which were submitted.

In a letter dated November 30, 2009, EPA notified the applicant that, because crucial vehicle durability information being developed by the Department of Energy would not be available until mid-2010, EPA would be delaying its decision on the application until a sufficient amount of this information could be included in its analysis so that the most scientifically supportable decision could be made.[476] As the current Growth Energy waiver application is still

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[DDDDDD] Refer to Table 4.4-4 in Section 4.4 of the RIA.

under review, EPA believes it is appropriate to address aspects of the mid-level blend waiver in its decision announcement on the waiver application as opposed to dealing with the comments and evaluation of the potential waiver in today's final rule.

Although EPA has yet to make a waiver decision, since its approval could have a significant impact on our analyses that are based on the use of E85, as a sensitivity analysis, we have evaluated the impacts that E15 could have on ethanol consumption feasibility. More specifically, we have assessed the impacts of a partial waiver for newer technology vehicles consistent with the direction of EPA's November 30, 2009 letter.

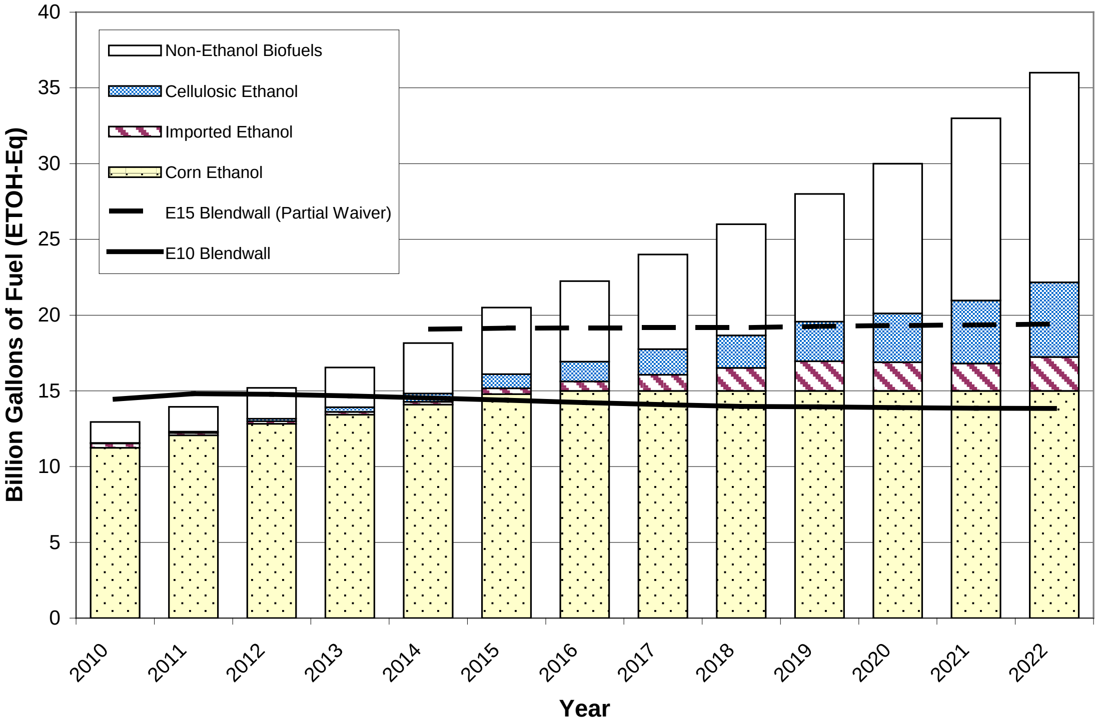
For our analysis, we assumed that E10 would need to continue to co-exist for legacy and non-road equipment based on consumer demand regardless of any waiver decision. As shown in Figures 1.7-5 through 1.7-7, we assumed that the percentage of gasoline energy consumed by nonroad, heavy-duty gasoline vehicles, and motorcycles would be about 8% based on information obtained from ORNL's Transportation Energy Data Book.[477] For analysis purposes, we assumed E10 would be marketed as premium-grade gasoline (the universal fuel), E15 would be marketed as regular-grade gasoline (to maximize ethanol throughput) and, like today, midgrade would be blended from the two fuels to make a 12.5 vol% blend (E12.5). In addition, we assumed that some E15-capable vehicles would continue to choose E10 or E12.5 based on today's premium and midgrade sales shown below in Table 1.7-4.

**Table 1.7-4.**
**Mid-level Ethanol Blend Assumptions**

| Grade of Gasoline | % of CG Sales* | Ethanol Content |
|---|---|---|
| Regular | 86.5% | 10.0% |
| Midgrade | 5.0% | 12.5% |
| Premium | 8.5% | 15.0% |
| *Petroleum Marketing Annual 2008, Table 45 | | |

In the event of a partial waiver, it is unclear how long it would take for E15 to be fully deployed or whether it would ever be available nationwide. For analysis purposes, we made the simplifying assumption that E15 would be fully phased in and available at all retail stations nationwide by the time the nation hit the blend wall, or by around 2014 for our primary mid-ethanol control case shown in Figure 1.7-14.

## Figure 1.7-14
## Max E15 Ethanol Consumption Compared to Mid-Ethanol Control Case



As modeled, a partial waiver for E15 could increase the ethanol consumption potential from conventional vehicles to about 19 billion gallons. Under our primary control case (shown in Figure 1.7-14), E15 could postpone the blend wall by up to five years, or to 2019. Although E15 would fall short of meeting the RFS2 requirements under this scenario, it could provide interim relief while the country ramps up non-ethanol cellulosic biofuel production and/or expands E85/FFV infrastructure.

Under our low-ethanol case, a partial waiver for E15 could eliminate the need for additional FFV/E85 infrastructure all together. Similarly, for our high-ethanol case, E15 could eliminate the need for FFV or E85 infrastructure mandates or postpone the blend wall by about 3 years from about 2013 to 2016. These scenarios are shown in Figures 1.7-15 and 1.7-16.

## Figure 1.7-15
## Max E15 Ethanol Consumption Compared to Low-Ethanol Control Case

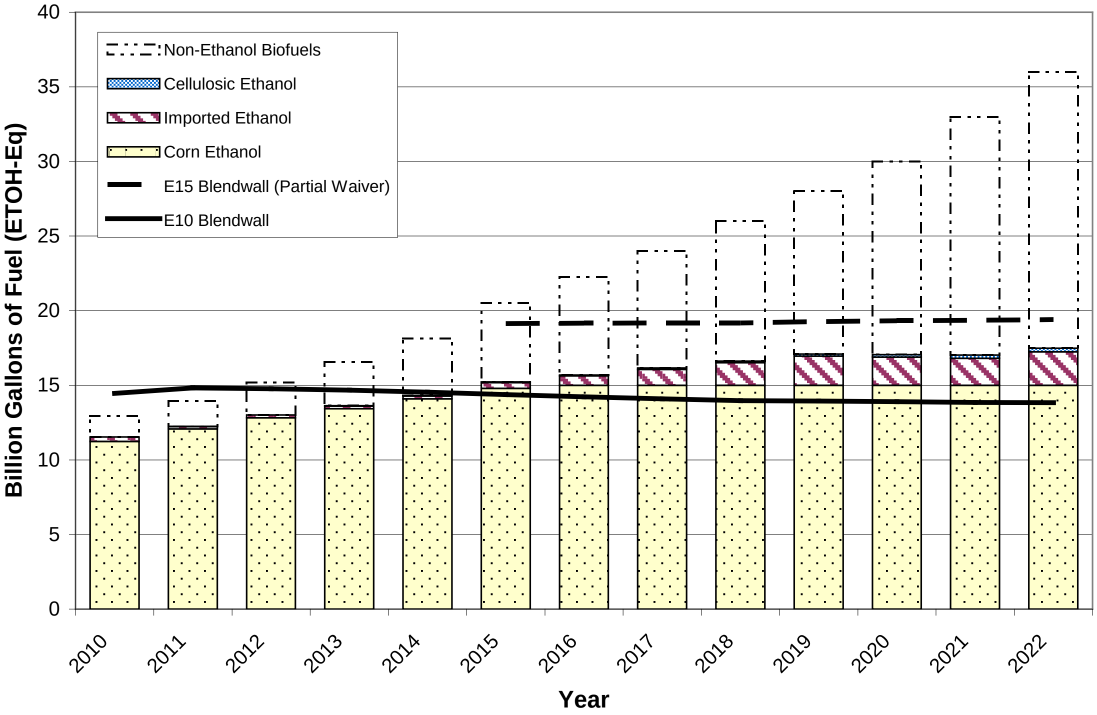
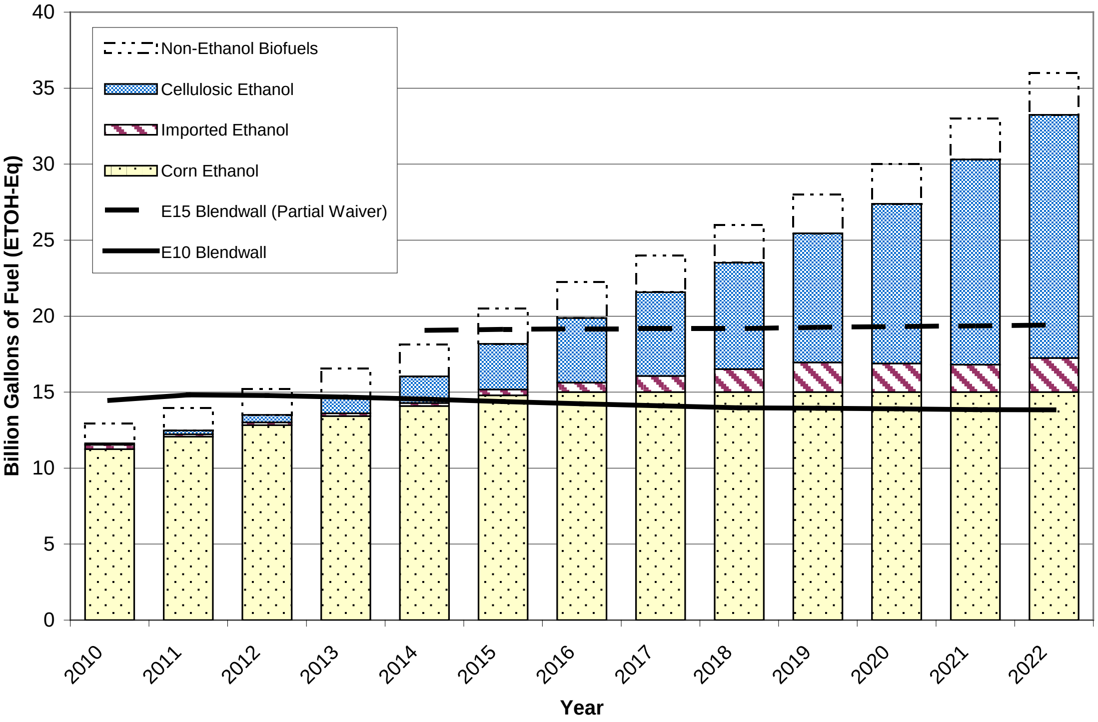


**Figure 1.7-16**
**Max E15 Ethanol Consumption Compared to High-Ethanol Control Case**



## 1.8 Inputs Used for the Air Quality Modeling

The information presented in Section 1.5 reflects our most current assessment of the renewable fuels industry and our projections through 2022 to meet the RFS2 standards. In addition, Section 1.7 reflects our most current assessment on how the renewable fuel might be consumed and the associated challenges, e.g., E10 blend wall, etc. The information presented in these sections serves as the basis for various final rulemaking impact analyses, including cost. However, the air quality modeling and some of the fuel distribution analyses had to begin prior to this assessment being completed. As a result, they relied on industry assessments carried out for the NPRM. This section presents the relevant NPRM assessment which served as the basis for these analyses.

### 1.8.1 Ethanol Inputs

### 1.8.1.1 Corn Ethanol Inputs

1.8.1.1.1 Existing Corn/Starch Ethanol Production

At the time of our May 2008 corn ethanol plant assessment used for air quality modeling, there were 158 fuel ethanol plants operating in the U.S. with a combined production capacity of

9.2 billion gallons per year.[EEEEEE478479] The majority of ethanol (nearly 89% by volume) was produced exclusively from corn. Another 11% came from a blend of corn and/or similarly processed grains (milo, wheat, or barley) and less than half a percent was produced from cheese whey, waste beverages, and sugars/starches combined. A summary of the feedstocks utilized by the U.S. ethanol industry as of May 2008 is found in Table 1.8-1.

**Table 1.8.1**
**May 2008 Corn/Starch Ethanol Production Capacity by Feedstock**

| Plant Feedstock (Primary Listed First) | Capacity MGY | % of Capacity | No. of Plants | % of Plants |
|---|---|---|---|---|
| Corn[a] | 8,141 | 88.8% | 131 | 82.9% |
| Corn, Milo[b] | 704 | 7.7% | 14 | 8.9% |
| Corn, Wheat | 130 | 1.4% | 1 | 0.6% |
| Corn, Wheat, Milo | 115 | 1.3% | 2 | 1.3% |
| Milo | 3 | 0.0% | 1 | 0.6% |
| Wheat, Milo | 50 | 0.5% | 1 | 0.6% |
| Cheese Whey | 8 | 0.1% | 2 | 1.3% |
| Waste Beverages[c] | 13 | 0.1% | 4 | 2.5% |
| Waste Sugars & Starches[d] | 7 | 0.1% | 2 | 1.3% |
| **Total** | **9,169** | **100%** | **158** | **100%** |

[a] Includes one facility processing seed corn, one facility also operating a pilot-level cellulosic ethanol plant, and six facilities with plans to build pilot-level cellulosic ethanol plants or incorporate biomass feedstocks in the future.

[b] Includes one facility processing small amounts of molasses in addition to corn and milo.

[c] Includes two facilities processing brewery waste.

[d] Includes one facility processing potato waste that intends to add corn in the future.

The corn ethanol industry relies primarily on natural gas. At the time of our May 2008 plant assessment, 134 of the 158 corn/starch ethanol plants burned natural gas (exclusively).[FFFFFF] In addition, three burned a combination of natural gas and biomass, one burned a combination of natural gas, landfill syngas and wood, while one burned a combination of natural gas and syrup from the process. In addition, 18 plants burned coal as their primary fuel and one burned a combination of coal and biomass. Our research suggested that 24 plants utilized cogeneration or combined heat and power (CHP) technology at the time of our

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[EEEEEE] Our May 2008 corn/starch ethanol industry characterization was based on a variety of data sources including: Renewable Fuels Association (RFA) Ethanol Biorefinery Locations (updated April 2, 2008); Ethanol Producer Magazine (EPM) Current plant list (last modified on April 14, 2008), and ethanol producer websites. The baseline does not include ethanol plants whose primary business is industrial or food-grade ethanol production. Where applicable, ethanol plant production levels were used in lieu of nameplate capacities to estimate plant production. The baseline does not include U.S. plants that were idled as of May 2008 or plants that might be located in the Virgin Islands or U.S. territories.

[FFFFFF] Facilities were assumed to burn natural gas if the plant boiler fuel was unspecified or unavailable on the public domain.

assessment. A summary of the energy sources and CHP technology utilized by the U.S. ethanol industry as of May 2008 is found in Table 1.8-2.

**Table 1.8.2.**
**May 2008 Corn/Starch Ethanol Production Capacity by Energy Source**

| **Plant Energy Source (Primary Listed First)** | **Capacity MGY** | **% of Capacity** | **No. of Plants** | **% of Plants** | **CHP Tech.** |
|---|---:|---:|---:|---:|---:|
| Coal[a] | 1,720 | 18.8% | 18 | 11.4% | 8 |
| Coal, Biomass | 50 | 0.5% | 1 | 0.6% | 0 |
| Natural Gas[b] | 7,141 | 77.9% | 134 | 84.8% | 15 |
| Natural Gas, Biomass[c] | 113 | 1.2% | 3 | 1.9% | 1 |
| Natural Gas, Landfill Syngas, Wood | 100 | 1.1% | 1 | 0.6% | 0 |
| Natural Gas, Syrup | 46 | 0.5% | 1 | 0.6% | 0 |
| **Total** | **9,169** | **100.0%** | **158** | **100.0%** | **24** |

[a] Includes four plants that are permitted to burn biomass, tires, petroleum coke, and wood waste in addition to coal and one facility that intends to transition to biomass in the future.

[b] Includes one facility that intends to burn thin stillage biogas, five facilities that intend to transition to coal, and one facility that intends to switch to biomass in the future.

[c] Includes one facility processing bran in addition to natural gas.

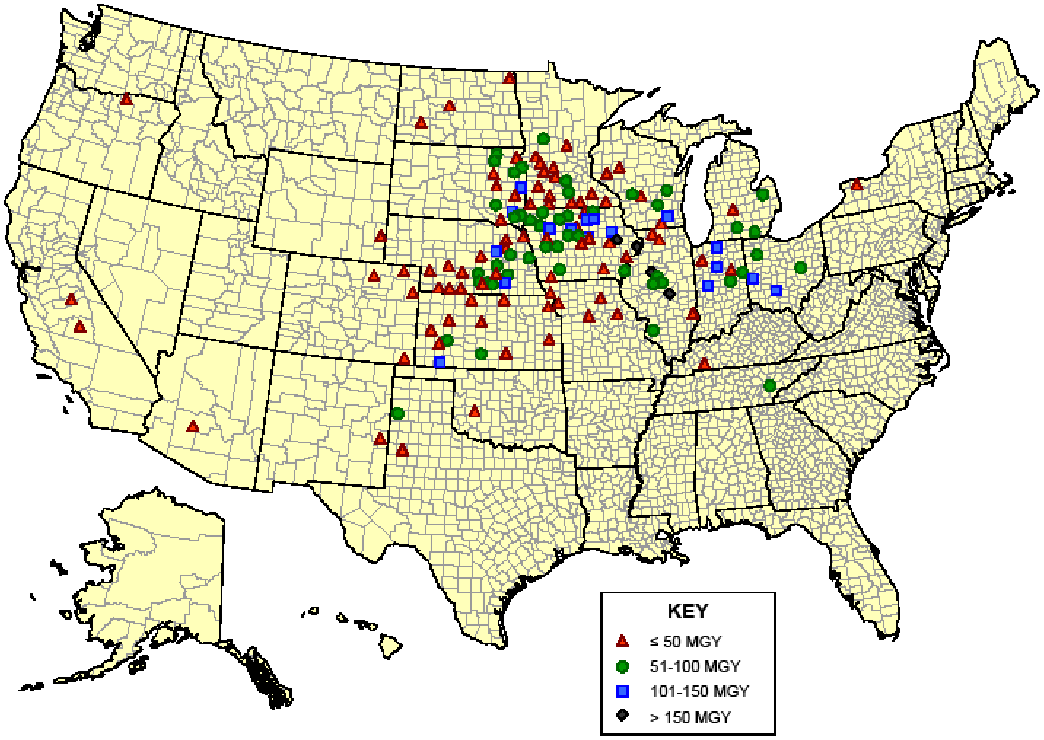
Besides a few plants located outside of the Corn Belt, the majority of ethanol is produced in PADD close to where the corn is grown. At the time of our May 2008 ethanol industry characterization, PADD 2 accounted for 94% (or 8.6 billion gallons) of the estimated ethanol production capacity as shown in Table 1.8.-3 below.

**Table 1.8-3.**
**May 2008 Corn/Starch Ethanol Production Capacity by PADD**

| **PADD** | **Capacity MGY** | **% of Capacity** | **No. of Plants** | **% of Plants** |
|---|---:|---:|---:|---:|
| PADD 1 | 50 | 0.5% | 2 | 1.3% |
| PADD 2 | 8,619 | 94.0% | 140 | 88.6% |
| PADD 3 | 170 | 1.9% | 3 | 1.9% |
| PADD 4 | 160 | 1.7% | 7 | 4.4% |
| PADD 5 | 171 | 1.9% | 6 | 3.8% |
| **Total** | **9,169** | **100.0%** | **158** | **100.0%** |

Leading the Midwest in ethanol production were Iowa, Nebraska, Illinois, South Dakota and Minnesota. Together, these five states' 93 ethanol plants accounted for 67 percent of the nation's ethanol production capacity in May 2008. For a map of the ethanol plant locations and a summary of ethanol production capacity by state, refer to Figure 1.8.1 and Table 1.8.4 below.

## Figure 1.8.1.
## May 2008 Corn/Starch Ethanol Plant Locations



## Table 1.8-4
## May 2008 Corn/Starch Ethanol Production Capacity by State

| State | Capacity MGY | % of Capacity | No. of Plants | % of Plants |
|---|---:|---:|---:|---:|
| Iowa | 2,282 | 24.9% | 30 | 19.0% |
| Nebraska | 1,278 | 13.9% | 22 | 13.9% |
| Illinois | 941 | 10.3% | 9 | 5.7% |
| South Dakota | 892 | 9.7% | 14 | 8.9% |
| Minnesota | 749 | 8.2% | 18 | 11.4% |
| Indiana | 540 | 5.9% | 7 | 4.4% |
| Wisconsin | 479 | 5.2% | 8 | 5.1% |
| Kansas | 464 | 5.1% | 12 | 7.6% |
| Ohio | 345 | 3.8% | 4 | 2.5% |
| Michigan | 214 | 2.3% | 4 | 2.5% |
| Missouri | 202 | 2.2% | 5 | 3.2% |
| Colorado | 146 | 1.6% | 5 | 3.2% |
| Texas | 140 | 1.5% | 2 | 1.3% |
| North Dakota | 125 | 1.4% | 3 | 1.9% |
| California | 81 | 0.9% | 4 | 2.5% |
| Tennessee | 66 | 0.7% | 1 | 0.6% |
| New York | 50 | 0.5% | 1 | 0.6% |
| Arizona | 50 | 0.5% | 1 | 0.6% |
| Kentucky | 40 | 0.4% | 2 | 1.3% |
| Oregon | 40 | 0.4% | 1 | 0.6% |
| New Mexico | 30 | 0.3% | 1 | 0.6% |
| Wyoming | 9 | 0.1% | 1 | 0.6% |
| Idaho | 5 | 0.1% | 1 | 0.6% |
| Oklahoma | 2 | 0.0% | 1 | 0.6% |
| Georgia | 0 | 0.0% | 1 | 0.6% |
| **Total** | **9,169** | **100.0%** | **158** | **100.0%** |

### 1.8.1.1.2 Forecasted Growth in Corn/Starch Ethanol Production Under RFS2

According to our industry assessment, there were 59 ethanol plants under construction or expanding as of May 2008 with a combined production capacity of 5.2 billion gallons per year.[GGGGGG] These projects were at various phases of construction from conducting land stabilization work, to constructing tanks and installing ancillary equipment, to completing start-up activities. We assumed that all this capacity would eventually come online as well as a number of other projects that were at advanced stages of planning at the time of our May 2008 industry assessment.

Once all the aforementioned projects are complete, we projected that there would be 216 corn/starch ethanol plants operating in the U.S. with a combined production capacity of about 15 billion gallons per year. Much like today's ethanol production facilities, the overwhelming majority of new plant capacity (95% by volume) was expected to come from corn-fed plants. The remainder was forecasted to come from plants processing a blend of corn and milo. A summary of the forecasted ethanol production by feedstock under the RFS2 program based on our May 2008 plant assessment is found in Table 1.8-5.

**Table 1.8-5.
Projected RFS2 Ethanol Production Capacity by Feedstock
(Based on May 2008 Ethanol Industry Characterization)**

| | New Plants/Exp. | | Total RFS2 Est. | |
|---|---|---|---|---|
| **Plant Feedstock (Primary Listed First)** | **Capacity MGY** | **No. of Plants** | **Capacity MGY** | **No. of Plants** |
| Corn[a] | 5,526 | 54 | 13,666 | 185 |
| Corn, Milo[b] | 303 | 4 | 1,007 | 18 |
| Corn, Wheat | 0 | 0 | 130 | 1 |
| Corn, Wheat, Milo | 0 | 0 | 115 | 2 |
| Milo | 0 | 0 | 3 | 1 |
| Wheat, Milo | 0 | 0 | 50 | 1 |
| Cheese Whey | 0 | 0 | 8 | 2 |
| Waste Beverages[c] | 0 | 0 | 13 | 4 |
| Waste Sugars & Starches[d] | 0 | 0 | 7 | 2 |
| **Total** | **5,829** | **58** | **14,998** | **216** |

[a] Includes one facility processing seed corn, one facility also operating a pilot-level cellulosic ethanol plant, and six facilities with plans to build pilot-level cellulosic ethanol plants or incorporate biomass feedstocks in the future.

[b] Includes one facility processing small amounts of molasses in addition to corn and milo.

[c] Includes two facilities processing brewery waste.

[d] Includes one facility processing potato waste that intends to add corn in the future.

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[GGGGGG] Based on Renewable Fuels Association (RFA), Ethanol Biorefinery Locations – Under Construction/Expansions (updated April 4, 2008); Ethanol Producer Magazine (EPM), Under Construction plant list (last modified on April 14, 2008), ethanol producer websites, and follow-up correspondence with ethanol producers.

Based on May 2008 industry plans, the majority of new corn/grain ethanol production capacity (82% by volume) was predicted to come from new or expanded plants burning natural gas. Additionally, we forecasted one new plant burning a combination of natural gas and syrup (from the process) and an expansion at an existing facility burning natural gas and biomass. Our predictions also suggest two new coal-fired ethanol plants and three expansions at existing coal-fired plants.[HHHHHH] Finally, we projected three new plants burning alternative fuels – one relying on manure biogas, one burning biomass, and one burning a combination of biomass and thin stillage from the process.[IIIII] Our research indicated that nine of the 58 new plants would utilize cogeneration, bringing the total number of CHP facilities to 33. A summary of the forecasted ethanol plant energy sources in 2022 under the RFS2 program is found in Table 1.8-6.

**Table 1.8-6.**
**Projected Near-Term Corn/Starch Ethanol Production Capacity by Energy Source**
**(Based on May 2008 Ethanol Industry Characterization)**

| | **New Plants/Exp.** | | **Total RFS2 Est.** | | |
|---|---|---|---|---|---|
| **Plant Energy Source (Primary Listed First)** | **Capacity MGY** | **No. of Plants** | **Capacity MGY** | **No. of Plants** | **CHP Tech.** |
| Biomass | 88 | 1 | 88 | 1 | 0 |
| Coal[a] | 740 | 4 | 2,460 | 22 | 12 |
| Coal, Biomass | 0 | 0 | 50 | 1 | 0 |
| Manure Biogas | 115 | 1 | 115 | 1 | 0 |
| Natural Gas[b] | 4,776 | 50 | 11,917 | 184 | 19 |
| Natural Gas, Biomass[c] | 40 | 0 | 153 | 3 | 1 |
| Natural Gas, Landfill Biogas, Wood | 0 | 0 | 100 | 1 | 0 |
| Natural Gas, Syrup | 50 | 1 | 96 | 2 | 0 |
| Thin Stillage Biogas, Biomass | 20 | 1 | 20 | 1 | 1 |
| **Total** | **5,829** | **58** | **14,998** | **216** | **33** |

[a] Includes four existing plants and two under construction facilities that are permitted to burn biomass, tires, petroleum coke, and wood waste in addition to coal. Also includes one facility that intends to transition to biomass in the future.

[b] Includes one facility that intends to burn thin stillage biogas, six facilities that intend to transition to coal, and one facility that intends to switch to biomass in the future.

[c] Includes one facility processing bran in addition to natural gas.

The information presented in Table 1.8-6 is based on near-term production plans at the time of our May 2008 industry assessment. However, we anticipate additional growth in advanced ethanol production technologies in the future under the RFS2 program. For more on our projected 2022 utilization of these technologies under the RFS2 program, refer to Section 1.5.1.3.

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[HHHHHH] We anticipate that all the coal-fired corn ethanol plants would be grandfathered under the RFS2 program. For more on our grandfathering assessment, refer to Section 1.5.1.4.

[IIIII] Thin stillage is a process liquid with 5–10 percent solids taken out of the distillers grains via centrifuge. However, construction on this alternatively fuel ethanol plant near Heyburn, ID was since terminated. Accordingly, this plant was not included in our November 2009 RFS2 projections.

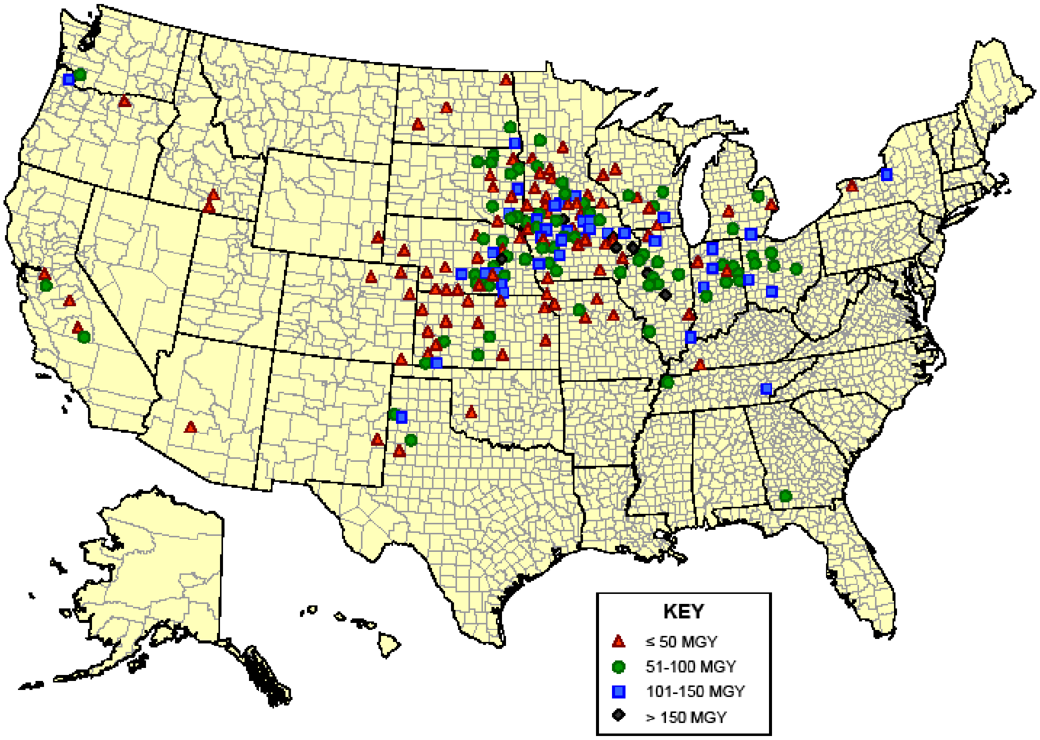
Based on our May 2008 assessment, 85% of new ethanol production capacity under RFS2 is expected to originate from PADD 2. For a summary of this and other forecasted PADD-level production projections, refer to Table 1.8-7.

## Table 1.8-7.
## Projected RFS2 Corn/Starch Ethanol Production Capacity by PADD
## (Based on May 2008 Ethanol Industry Characterization)

| | New Plants/Exp. | | Total RFS2 Est. | |
|---|---|---|---|---|
| **PADD** | **Capacity MGY** | **No. of Plants** | **Capacity MGY** | **No. of Plants** |
| PADD 1 | 214 | 2 | 264 | 4 |
| PADD 2 | 5,002 | 47 | 13,620 | 187 |
| PADD 3 | 215 | 2 | 385 | 5 |
| PADD 4 | 70 | 2 | 230 | 9 |
| PADD 5 | 328 | 5 | 499 | 11 |
| **Total** | **5,829** | **58** | **14,998** | **216** |

Our May 2008 assessment suggested that Iowa, Nebraska, and Illinois would continue to dominate ethanol production under RFS2 with a collective annual production capacity of about 7.5 billion gallons. Minnesota and Indiana were projected to be the fourth and fifth largest ethanol producers. A map of the forecasted corn ethanol plant locations based on our May 2008 assessment is provided in Figure 1.8-2 and a summary of the ethanol production capacity by state is presented in Table 1.8-8.

**Figure 1.8-2**
**Projected RFS2 Corn/Starch Ethanol Plant Locations**
**(Based on May 2008 Ethanol Industry Characterization)**



### Table 1.8-8.
### Projected RFS2 Corn/Starch Ethanol Production Capacity by State
### (Based on May 2008 Ethanol Industry Characterization)

| | New Plants/Exp. | | Total RFS2 Est. | |
|---|---|---|---|---|
| **State** | **Capacity MGY** | **No. of Plants** | **Capacity MGY** | **No. of Plants** |
| Iowa | 1,573 | 13 | 3,854 | 43 |
| Nebraska | 959 | 7 | 2,237 | 29 |
| Illinois | 465 | 4 | 1,406 | 13 |
| Minnesota | 440 | 4 | 1,189 | 22 |
| Indiana | 470 | 5 | 1,010 | 12 |
| South Dakota | 100 | 1 | 992 | 15 |
| Kansas | 203 | 4 | 667 | 16 |
| Wisconsin | 70 | 1 | 549 | 9 |
| Ohio | 185 | 3 | 530 | 7 |
| Texas | 215 | 2 | 355 | 4 |
| North Dakota | 210 | 2 | 335 | 5 |
| Michigan | 107 | 1 | 321 | 5 |
| Missouri | 60 | 1 | 262 | 6 |
| California | 160 | 3 | 241 | 7 |
| Tennessee | 160 | 1 | 226 | 2 |
| New York | 114 | 1 | 164 | 2 |
| Oregon | 113 | 1 | 153 | 2 |
| Colorado | 0 | 0 | 146 | 5 |
| Georgia | 100 | 1 | 100 | 2 |
| Idaho | 70 | 2 | 75 | 3 |
| Washington | 55 | 1 | 55 | 1 |
| Arizona | 0 | 0 | 50 | 1 |
| Kentucky | 0 | 0 | 40 | 2 |
| New Mexico | 0 | 0 | 30 | 1 |
| Wyoming | 0 | 0 | 9 | 1 |
| Oklahoma | 0 | 0 | 2 | 1 |
| **Total** | **5,829** | **58** | **14,998** | **216** |

### 1.8.1.2 Projected Ethanol Import Locations

A discussion of the sugarcane ethanol imports that might come directly from Brazil versus through the CBI countries is contained in Section 1.5.2. However, to provide upstream inputs for AQ modeling and distribution purposes, we needed to estimate imports based on their country of origin and projected U.S. destination, i.e., port location.

### 1.8.1.2.1 Origin of Projected Imports

To estimate the future breakdown of ethanol imports from CBI countries by country of origin, we evaluated historical ethanol import data from the International Trade Commission (ITC) and trends regarding potential growth in such imports. Table 1.8-9 contains 2005-2007 data from the ITC on ethanol imports from CBI countries.[480] Table 1.8-10 contains January – March 2008 data from the ITC on ethanol imports from CBI countries.[481]

**Table 1.8-9. Ethanol Imports from CBI Countries 2005-2007**

| | 2005 | | 2006 | | 2007 | |
|---|---|---|---|---|---|---|
| | % of CBI imports | Volume (Million Gallons) | % of CBI imports | Volume (Million Gallons) | % of CBI imports | Volume (Million Gallons) |
| Costa Rica | 32% | 33.4 | 22% | 35.9 | 17% | 39.3 |
| El Salvador | 23% | 23.7 | 23% | 38.5 | 32% | 73.3 |
| Jamaica | 35% | 36.3 | 40% | 66.8 | 33% | 75.2 |
| Trinidad and Tobago | 10% | 10 | 15% | 24.8 | 19% | 42.7 |

Source: International Trade Commission

**Table 1.8-10. Ethanol Imports from CBI Countries, January through March 2008**

| | January | | February | | March | |
|---|---|---|---|---|---|---|
| | % of CBI imports | Volume (Million Gallons) | % of CBI imports | Volume (Million Gallons) | % of CBI imports | Volume (Million Gallons) |
| Costa Rica | 26% | 5.4 | 27% | 5.4 | 0 | 0 |
| El Salvador | 13% | 2.6 | 0 | 0 | 23% | 4.6 |
| Jamaica | 19% | 4.0 | 32% | 6.4 | 39% | 7.9 |
| Trinidad and Tobago | 20% | 4.1 | 21% | 4.2 | 29% | 6 |
| Virgin Islands | 22% | 4.6 | 21% | 4.2 | 9% | 1.9 |

Source: International Trade Commission

Based on our review of the January through March 2008 data, we assumed that ethanol exports from the Virgin Islands would continue to grow to equal those of Trinidad and Tobago in 2022. By accommodating this assumption into our review of 2005 though 2007 historical ethanol import data, we arrived at our projections regarding the future breakdown of ethanol imports from CBI countries which is contained in Table 1.8-11

**Table 1.8-11.**
**Projected Future Breakdown of Ethanol Imports from CBI Countries**

| | % of Total Ethanol Imports from CBI Countries |
|---|---|
| Costa Rica | 20% |
| El Salvador | 20% |
| Jamaica | 30% |
| Trinidad and Tobago | 15% |
| Virgin Islands | 15% |

### 1.8.1.2.2 Destination of Projected Imports

As explained above, to determine where imported ethanol might enter the United States, we started by looking at historical ethanol import data and made assumptions as to which countries would likely contribute to the CBI ethanol volumes and to what extent.

From there, we looked at 2006-2007 import data and estimated the general destination of Brazilian ethanol and the five contributing CBI countries' domestic imports.[482] Based on these countries' geographic locations and import histories, we estimated that in 2022 82% of the ethanol would be imported to the East and Gulf Coasts and the remaining 18% would go to the West Coast and Hawaii. The destination of imports from Brazil and the CBI countries in 2022 is detailed in Table 1.8-12.

**Table 1.8-12**
**2022 Projected Destination of Ethanol Imports from Brazil and CBI Countries Based on 2006-2007 Import Data**

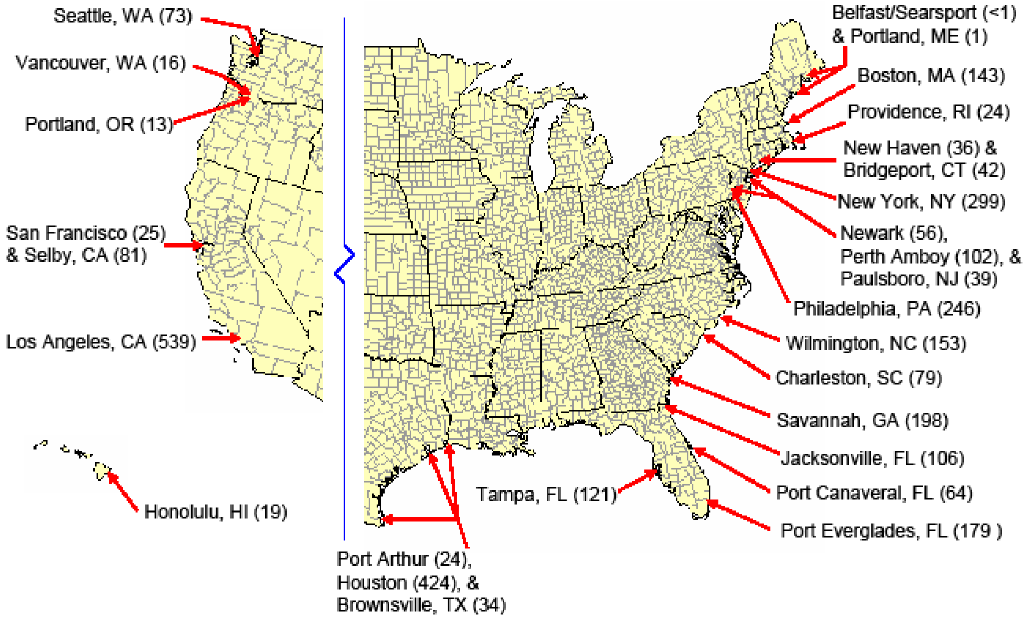
| Origin | Destination of Ethanol Imports (% of imported volume) | | |
|---|---|---|---|
| | West Coast | Hawaii | East & Gulf Coasts |
| Costa Rica | 83% | 35% | 47% |
| El Salvador | 18% | 9% | 88% |
| Jamaica | 3% | 0% | 17% |
| Trinidad & Tobago | 0% | 32% | 68% |
| Virgin Islands | 3% | 9% | 88% |
| Brazil (direct) | 7% | 0% | 93% |
| Total | 11% | 7% | 82% |

Source: Energy Information Administration historical gasoline and ethanol import data: http://www.eia.doe.gov/oil_gas/petroleum/data_publications/company_level_imports/cli_historical.html

To estimate the 2022 ethanol import locations on a finer level, we looked at coastal ports that had received ethanol or finished gasoline imports in 2006. We chose to include ports which imported finished gasoline (in addition to ethanol) because we believe finished gasoline will be one of the first petroleum products to be replaced under the proposed RFS2 rule. And presumably, these ports cities already have existing gasoline storage tanks that could be retrofitted to accommodate fuel ethanol. All together, we arrived at 28 potential ports in 16 coastal states that could receive ethanol imports in 2022 (refer to Figure 1.8-3 below).[JJJJJJ]

To determine how much ethanol would arrive at each port location, we started by examining each receiving state's imported ethanol consumption potential. To do this, we considered each state's maximum ethanol consumption potential (based on projected gasoline energy demand) and deducted the projected 2022 corn and cellulosic ethanol production (detailed in Sections 1.8.1.1 and 1.8.1.3, respectively). Once we determined the amount of imported ethanol that each state would receive in 2022 under RFS2, for states with multiple ethanol ports, we allocated the ethanol among port locations based on each port county's relative energy demand - using projected 2022 vehicle miles traveled (VMT) from EPA's MOVES model 2022 VMT. A summary of the projected ethanol imports volumes by port location is found in Figure 1.8-3.

**Figure 1.8-3.**
**Projected RFS2 Ethanol Import Locations and Volumes (Million Gallons)[KKKKKK]**



Total U.S. Ethanol Imports in 2022 = 3,140 Million Gallons

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[JJJJJJ] We are considering adding Hampton Roads, VA and Baltimore, MD to the list of future ethanol import locations and may adjust our analysis for the final rule accordingly.

[KKKKKK] We are considering adding Hampton Roads, VA and Baltimore, MD to the list of future ethanol import locations and may adjust our analysis for the final rule accordingly.

### 1.8.1.3 Cellulosic Ethanol Plant Siting

As explained in Section 1.5.3, cellulosic biofuel production capacity needs to expand greatly in order to meet the cellulosic biofuel mandate of 16 billion gallons by 2022. While current production plans provide an initial idea of the types of feedstocks and potential plant locations that are being considered by biofuel producers, future production will be highly dependent on acquiring relatively cost-effective feedstocks in sufficient quantities.

A wide variety of feedstocks can be used for cellulosic biofuel production, including agricultural residues, forestry biomass, the certain renewable portions of municipal solid waste and construction and demolition waste and energy crops. These feedstocks are currently much more difficult to convert into ethanol than traditional starch/corn crops or at least require new and different processes because of the more complex structure of cellulosic material.

#### 1.8.1.3.1 Summary of Plant Siting Results

As long lead times were required for our air quality modeling, it was necessary to use available data at the time on the likely cellulosic feedstocks and projected locations of cellulosic facilities for production of 16 billion gallons cellulosic biofuel by 2022. Our original plant siting analysis for cellulosic ethanol facilities used the most current version of outputs from FASOM at the time, which was from April 2008. Therefore, the version used for the majority of other analyses in the rest of this package is different from the results presented below.

Our cellulosic ethanol plant siting analysis assumed that the following cellulosic feedstock and volumes would be used, as shown in Table 1.8-13.

**Table 1.8-13.**
**Cellulosic Feedstocks Assumed to Meet EISA in 2022**
**(NPRM version for AQ Modeling)**

| **Feedstock** | **Volume (Ethanol-equivalent Bgal)** |
|---|---|
| Agricultural Residues | 9.1 |
| Corn Stover | 7.8 |
| Sugarcane Bagasse[LLLLLL] | 1.2 |
| Sweet Sorghum Pulp | 0.1 |
| Forestry Biomass | 3.8 |
| Urban Waste | 2.2 |
| Dedicated Energy Crops (Switchgrass) | 0.9 |
| Total | 16.0 |

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[LLLLLL] Bagasse is a byproduct of sugarcane crushing and not technically an agricultural residue. Sweet sorghum pulp is also a byproduct of sweet sorghum processing. We have included it under this heading for simplification due to sugarcane being an agricultural feedstock.

Future cellulosic biofuel plant siting was based on the types of feedstocks that would be most economical as shown in Table 1.8-13, above. As cellulosic biofuel refineries will likely be located close to biomass resources in order to take advantage of lower transportation costs, we've assessed the potential areas in the U.S. that grow the various feedstocks chosen. To do this, we used data on harvested acres by county for crops that are currently grown today, such as corn stover and sugarcane (for bagasse).[483] In some cases, crops are not currently grown, but have the potential to replace other crops or pastureland (e.g., dedicated energy crops). We used the output from our economic modeling (FASOM) to help us determine which types of land are likely to be replaced by newly grown crops. For forest residue biomass, the U.S. Forest Service provided supply curve data by county showing the available tons produced. Urban waste (MSW wood, paper, and C&D debris) was estimated to be located near large population centers. Refer to Section 1.8.1.3.2 below for more detailed information.

Using feedstock availability data by county/city, we located potential cellulosic sites across the U.S. that could justify the construction of a cellulosic plant facility. Table 1.8-14 shows the volume of cellulosic facilities by feedstock by state projected for 2022. Table 1.8-15 lists the 180 cellulosic ethanol facilities that we project could potentially be used to produce 16 Bgal of cellulosic biofuel by 2022. The total volumes given in Table 1.8-14 match the total volumes given in Table 1.8-15 within a couple hundred million gallons. As these differences are relatively small, we believe the cellulosic facilities sited are a good estimate of potential locations. See Figure 1.8-4 for a visual representation of the locations of these facilities.

### Table 1.8-14.
### Projected Cellulosic Ethanol Volumes by State (million gallons in 2022)

| State | Total Volume | Ag Volume | Energy Crop Volume | Urban Waste Volume | Forestry Volume |
|---|---|---|---|---|---|
| Alabama | 532 | 0 | 0 | 140 | 392 |
| Arkansas | 298 | 0 | 0 | 0 | 298 |
| California | 450 | 0 | 0 | 221 | 229 |
| Colorado | 28 | 0 | 0 | 28 | 0 |
| Florida | 421 | 390 | 0 | 31 | 0 |
| Georgia | 437 | 0 | 0 | 67 | 370 |
| Illinois | 1,525 | 1,270 | 0 | 198 | 58 |
| Indiana | 1,109 | 948 | 0 | 101 | 60 |
| Iowa | 1,697 | 1,635 | 0 | 32 | 30 |
| Kansas | 310 | 250 | 0 | 29 | 32 |
| Kentucky | 70 | 70 | 0 | 0 | 0 |
| Louisiana | 1,001 | 590 | 0 | 103 | 308 |
| Maine | 191 | 0 | 0 | 2 | 189 |
| Michigan | 505 | 283 | 0 | 171 | 51 |
| Minnesota | 876 | 750 | 0 | 50 | 76 |
| Mississippi | 214 | 0 | 0 | 22 | 192 |
| Missouri | 654 | 504 | 0 | 78 | 72 |
| Montana | 92 | 0 | 0 | 9 | 83 |
| Nebraska | 956 | 851 | 0 | 31 | 75 |
| Nevada | 17 | 0 | 0 | 17 | 0 |
| New Hampshire | 171 | 0 | 35 | 29 | 107 |
| New York | 72 | 0 | 0 | 72 | 0 |
| North Carolina | 315 | 0 | 0 | 98 | 217 |
| Ohio | 598 | 410 | 0 | 156 | 32 |
| Oklahoma | 793 | 0 | 777 | 0 | 16 |
| Oregon | 244 | 0 | 0 | 44 | 200 |
| Pennsylvania | 42 | 0 | 0 | 42 | 0 |
| South Carolina | 213 | 0 | 0 | 57 | 156 |
| South Dakota | 434 | 350 | 0 | 6 | 78 |
| Tennessee | 97 | 0 | 0 | 19 | 78 |
| Texas | 576 | 300 | 0 | 131 | 145 |
| Virginia | 197 | 0 | 0 | 95 | 102 |
| Washington | 175 | 0 | 0 | 17 | 158 |
| West Virginia | 149 | 0 | 101 | 0 | 48 |
| Wisconsin | 581 | 432 | 0 | 43 | 106 |
| Total Volume | 16,039 | 9,034 | 913 | 2,139 | 3,955 |

## Table 1.8-15.
## Projected Cellulosic Facilities
## (million gallons in 2022)

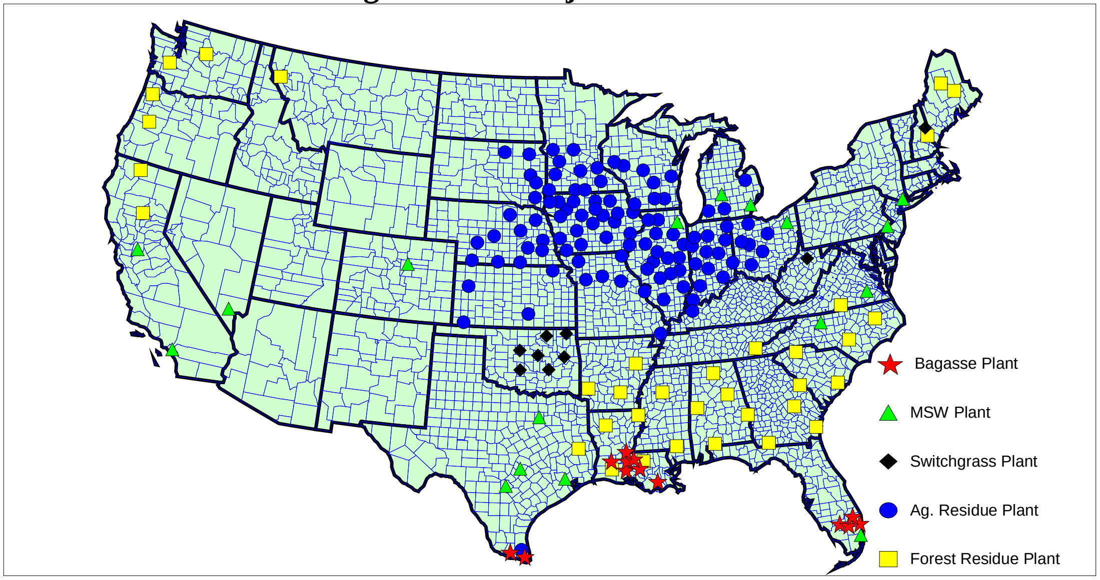
| County | State | Total Volume (million gallons/yr) |
|---|---|---|
| Escambia | Alabama | 112 |
| Greene | Alabama | 108 |
| Morgan | Alabama | 96 |
| Russell | Alabama | 101 |
| Talledega | Alabama | 115 |
| Cleveland | Arkansas | 99 |
| Howard | Arkansas | 97 |
| Woodruff | Arkansas | 102 |
| Butte | California | 94 |
| Orange | California | 133 |
| San Joaquin | California | 120 |
| Siskiyou | California | 102 |
| Adams | Colorado | 28 |
| Broward | Florida | 31 |
| Hendry | Florida | 90 |
| Palm Beach | Florida | 100 |
| Palm Beach | Florida | 100 |
| Palm Beach | Florida | 100 |
| Glynn | Georgia | 108 |
| Grady | Georgia | 130 |
| Richmond | Georgia | 101 |
| Treutlen | Georgia | 98 |
| Bureau | Illinois | 130 |
| Carroll | Illinois | 77 |
| Champaign | Illinois | 89 |
| Coles | Illinois | 77 |
| De Witt | Illinois | 100 |
| Du Page | Illinois | 128 |
| Grundy | Illinois | 77 |
| Iroquois | Illinois | 80 |
| Knox | Illinois | 89 |
| Menard | Illinois | 99 |
| Montgomery | Illinois | 78 |
| Morgan | Illinois | 67 |
| Ogle | Illinois | 95 |
| Richland | Illinois | 81 |
| Shelby | Illinois | 68 |
| Tazewell | Illinois | 107 |
| Washington | Illinois | 85 |
| Benton | Indiana | 92 |
| Clinton | Indiana | 80 |
| Daviess | Indiana | 93 |
| De Kalb | Indiana | 91 |
| Fulton | Indiana | 74 |
| Jasper | Indiana | 82 |

|  |  |  |
|---|---|---|
| Jennings | Indiana | 94 |
| Madison | Indiana | 78 |
| Morgan | Indiana | 100 |
| Parke | Indiana | 92 |
| Union | Indiana | 82 |
| Vanderburgh | Indiana | 74 |
| Wells | Indiana | 77 |
| Benton | Iowa | 69 |
| Buchanan | Iowa | 83 |
| Buena Vista | Iowa | 84 |
| Cerro Gordo | Iowa | 79 |
| Chickasaw | Iowa | 82 |
| Des Moines | Iowa | 87 |
| Dubuque | Iowa | 70 |
| Franklin | Iowa | 80 |
| Grundy | Iowa | 83 |
| Guthrie | Iowa | 85 |
| Ida | Iowa | 88 |
| Mahaska | Iowa | 80 |
| Muscatine | Iowa | 83 |
| O Brien | Iowa | 80 |
| Page | Iowa | 81 |
| Palo Alto | Iowa | 75 |
| Pottawattamie | Iowa | 84 |
| Sioux | Iowa | 72 |
| Story | Iowa | 89 |
| Union | Iowa | 76 |
| Webster | Iowa | 86 |
| Logan | Kansas | 75 |
| Nemaha | Kansas | 78 |
| Sedgwick | Kansas | 71 |
| Stevens | Kansas | 87 |
| Webster | Kentucky | 70 |
| Bienville | Louisiana | 115 |
| E. Baton Rouge | Louisiana | 106 |
| E. Carroll | Louisiana | 103 |
| Jeff Davis | Louisiana | 87 |
| Allen | Louisiana | 50 |
| Avoyelles | Louisiana | 100 |
| Iberville | Louisiana | 90 |
| La Fourche | Louisiana | 50 |
| Lafayette | Louisiana | 100 |
| Pt. Coupe | Louisiana | 100 |
| St Landry | Louisiana | 100 |
| Penobscot | Maine | 100 |
| Piscataquis | Maine | 91 |
| Calhoun | Michigan | 109 |
| Ionia | Michigan | 117 |
| Tuscola | Michigan | 105 |
| Van Buren | Michigan | 89 |

|  |  |  |
|---|---|---|
| Wayne | Michigan | 85 |
| Chippewa | Minnesota | 92 |
| Dakota | Minnesota | 114 |
| Dodge | Minnesota | 86 |
| Faribault | Minnesota | 88 |
| Lyon | Minnesota | 84 |
| Martin | Minnesota | 95 |
| Rock | Minnesota | 73 |
| Sibley | Minnesota | 102 |
| Stearns | Minnesota | 68 |
| Stevens | Minnesota | 76 |
| Forrest | Mississippi | 107 |
| Grenada | Mississippi | 107 |
| Audrain | Missouri | 86 |
| Chariton | Missouri | 74 |
| Clark | Missouri | 89 |
| Gentry | Missouri | 95 |
| New Madrid | Missouri | 84 |
| Ray | Missouri | 100 |
| St. Louis | Missouri | 125 |
| Sanders | Montana | 92 |
| Boone | Nebraska | 98 |
| Custer | Nebraska | 84 |
| Harlan | Nebraska | 78 |
| Hitchcock | Nebraska | 83 |
| Holt | Nebraska | 91 |
| Lancaster | Nebraska | 74 |
| Lincoln | Nebraska | 81 |
| Nuckolls | Nebraska | 76 |
| Saunders | Nebraska | 100 |
| Wayne | Nebraska | 96 |
| York | Nebraska | 94 |
| Clark | Nevada | 17 |
| Carroll | New Hampshire | 136 |
| Carroll | New Hampshire | 35 |
| West Chester | New York | 72 |
| Cumberland | North Carolina | 110 |
| Forsyth | North Carolina | 104 |
| Martin | North Carolina | 102 |
| Auglaize | Ohio | 80 |
| Clinton | Ohio | 100 |
| Franklin | Ohio | 77 |
| Logan | Ohio | 75 |
| Portage | Ohio | 98 |
| Richland | Ohio | 83 |
| Wood | Ohio | 85 |
| Craig | Oklahoma | 130 |
| Grady | Oklahoma | 108 |
| Hughes | Oklahoma | 91 |
| Kingfisher | Oklahoma | 110 |

| | | |
|---|---|---|
| Lincoln | Oklahoma | 120 |
| Muskogee | Oklahoma | 118 |
| Osage | Oklahoma | 116 |
| Lane | Oregon | 126 |
| Yamhill | Oregon | 118 |
| Montgomery | Pennsylvania | 42 |
| Berkeley | South Carolina | 105 |
| Spartanburg | South Carolina | 108 |
| Day | South Dakota | 85 |
| Edmunds | South Dakota | 80 |
| Kingsbury | South Dakota | 98 |
| Lake | South Dakota | 83 |
| Turner | South Dakota | 89 |
| Monroe | Tennessee | 97 |
| Angelina | Texas | 114 |
| Bexar | Texas | 16 |
| Cameron | Texas | 100 |
| Dallas | Texas | 52 |
| Harris | Texas | 80 |
| Hidalgo | Texas | 100 |
| Travis | Texas | 14 |
| Willacy | Texas | 100 |
| Halifax | Virginia | 98 |
| Prince George | Virginia | 99 |
| Chelan | Washington | 78 |
| Thurston | Washington | 97 |
| Harrison | West Virginia | 149 |
| Calumet | Wisconsin | 91 |
| Dane | Wisconsin | 76 |
| Dunn | Wisconsin | 63 |
| Eau Claire | Wisconsin | 65 |
| Grant | Wisconsin | 68 |
| Jefferson | Wisconsin | 94 |
| Marquette | Wisconsin | 65 |
| Wood | Wisconsin | 59 |
| Total | | 16039 |

**Figure 1.8-4. Projected Cellulosic Facilities**



### 1.8.1.3.2 Assumptions and Details of Plant Siting Analysis

An important assumption in our siting analysis is that an excess of feedstock would have to be available for producing the biofuel. Banks are anticipated to require excess feedstock supply as a safety factor to ensure that the plant will have adequate feedstock available for the plant, despite any feedstock emergency, such as a fire, drought, infestation of pests etc. For our analysis we assumed that twice the feedstock of MSW, C&D waste, and forest residue would have to be available to justify the building of a cellulosic ethanol plant. For corn stover, we assumed 50 percent more feedstock than necessary. We used a lower safety factor for corn stover because it could be possible to remove a larger percentage of the corn stover in any year (usually only 50 percent or less of corn stover is assumed to be sustainably removed in any one year).[MMMMMM]

Another assumption that we made is that if multiple feedstocks are available in an area, each would be used as feedstocks for a prospective cellulosic ethanol plant. For example, a particular area might comprise a small or medium sized city, some forest and some agricultural land. We would include the MSW and C&D wastes available from the city along with the corn stover and forest residue for projecting the feedstock that would be processed by the particular cellulosic ethanol plant.

Each of the cellulosic plants was chosen to produce approximately 100 million gallons per year of ethanol. In some cases we had to resort to lower volumes due to limited resources in a given area. In other cases, we used greater than 100 million gallons per year because relatively close materials were available that would otherwise go unused. In addition, we limited biomass transport distances to be approximately 100 miles each way or less (radius from proposed facility), as large transport distances are economically prohibitive. We found that the majority of

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[MMMMMM] The FASOM results do not take into consideration these feedstock safety margins. Safety margins were used, however, for the plant siting analysis described in this section.

corn stover cellulosic facilities required smaller transport distances than the assumed 100 mile limit due to relatively close proximity to available feedstocks. Forest residues, on the other hand, typically required greater distances as collectable material appeared to be sparser.

Our analyses also take into account the locations of planned cellulosic facilities as well as any corn facilities or pulp and paper mills when we project where cellulosic plants are located into the future. While not all planned cellulosic facilities will likely come to fruition, it was important to look at the locations of these facilities as their locations are likely to be chosen for good reasons (i.e. close to resources, infrastructure in place, etc.). We analyzed current corn facilities and pulp and paper mill sites as well since they are likely to be close to their respective feedstocks (i.e. corn stover and wood residues) and could have many synergies with cellulosic biofuel production, such as shared steam and electricity production. However, this does not mean that we placed cellulosic facilities at all the locations where there are current corn facilities and pulp and paper mills. The locations are only used to help select areas that could be preferential towards building a cellulosic facility.

It is important to note, that there are many more factors other than feedstock availability to consider when eventually siting a plant. We have not taken into account, for example, water constraints, availability of permits, and sufficient personnel for specific locations. Nevertheless, our plant siting analysis provides a reasonable approximation for analysis purposes since it is not intended to predict precisely where actual plants will be located. Other work is currently being done that can help address some of these issues.[484]

For this analysis, we estimated MSW and C&D wood waste by state (similar to the analysis described in Section 1.1.2.4) and calculated the tons of MSW and C&D wood waste material generated per person per state. We used the estimate of MSW and C&D wood waste material generated per person per state (i.e. tons/person) along with data on the population sizes of the largest cities within the state to allocate the total waste material in a state to specific cities. Assuming that the majority of this waste is of negligible cost to a potential ethanol producer, we calculated a minimum size for a cellulosic plant dedicated to MSW and C&D wood waste for various locations in the U.S. Sizes ranged from 9-60 million gallons per year.

We did not consider small cities that might be able to justify a cellulosic ethanol plant because some other source of biomass is also available that, when combined with the MSW and C&D wood waste, can supply the cellulosic ethanol plant with sufficient feedstock. However, where non-MSW and C&D wood waste feedstocks are not available, we needed to estimate what the minimum plant size that would be competitive with other cellulosic ethanol plants.

We conducted this analysis early on before NREL provided us with the cost information for a biochemical cellulosic ethanol plant. Instead we used a representation made by NREL in 2007 for of a thermochemical ethanol plant. Using that cellulosic plant model we estimated the production cost for a 100 million gallon per year thermochemical plant which processed a cellulosic feedstock. We conducted this analysis in different parts of the country using different capital cost factors that account for how capital costs vary in different parts of the country. The different regions were Petroleum Administration for Defense Districts (PADDs) for which we have plant installation costs. In each part of the country, we estimated the cost of the ethanol produced processing the cellulosic feedstock assuming that the feedstock cost about $70 per dry ton. Next, we set the feedstock costs to zero cost in our cost spreadsheet and determined at what plant size, when scaling the capital costs as the plant size became smaller, the resulting cellulosic production costs matched those of the non-MSW and C&D wood waste plants. See Table 1.8-16.

**Table 1.8-16.**
**Breakeven Plant Size for MSW and C&D Wood Waste Cellulosic Ethanol Plants**

| | PADD 1 | PADD 2 | PADD 3 | PADD 4 | PADD 5 | CA |
|---|---|---|---|---|---|---|
| | | | | | | |
| Ethanol Production Cost (c/gal) | 1.33 | 1.24 | 1.10 | 1.29 | 1.19 | 1.57 |
| Breakeven Plant Size (million gals/yr) | 28 | 19 | 9 | 23 | 15 | 60 |

We then identified the cities that had large enough MSW and C&D wood waste to justify a dedicated cellulosic facility. By dedicated cellulosic facility, we mean that only MSW and C&D wood waste is used as a feedstock, as opposed to a facility that has multiple mixed feedstocks. Nineteen facilities were identified to meet such criteria, as shown in Table 1.8-17. The total contribution from dedicated cellulosic MSW and C&D wood waste is approximately 640 million gallons.

### Table 1.8-17.
### Projected Dedicated Cellulosic MSW and C&D Wood Waste Facilities by Location and Size for 2022

| | State | County | City | PADD | Size of Facility (Mgal) |
|---|---|---|---|---|---|
| 1 | Alabama | Jefferson | Birmington | 3 | 11 |
| 2 | Arizona | Maricopa | Phoenix | 5 | 20 |
| 3 | California | Los Angeles | Los Angeles | 5 | 56 |
| 4 | California | Riverside | Riverside | 5 | 24 |
| 5 | California | San Francisco | San Francisco | 5 | 17 |
| 6 | Colorado | Adams | Denver | 4 | 28 |
| 7 | Florida | Miami | Fort Lauderdale | 1 | 31 |
| 8 | Georgia | Cobb | Atlanta | 1 | 43 |
| 9 | Illinois | Cook | Chicago | 2 | 79 |
| 10 | Michigan | Oakland | Detroit | 2 | 33 |
| 11 | Nevada | Clark | Las Vegas | 5 | 17 |
| 12 | New York | New York City | New York | 1 | 72 |
| 13 | Oregon | Clackamas | Portland | 4 | 15 |
| 14 | Pennsylvania | Philadelphia | Philadelphia | 1 | 42 |
| 15 | Texas | Dallas | Dallas | 3 | 52 |
| 16 | Texas | Fort Bend | Houston | 3 | 49 |
| 17 | Texas | Bexar | San Antonio | 3 | 16 |
| 18 | Texas | Travis | Austin | 3 | 14 |
| 19 | Washington | King | Seattle | 5 | 17 |

We did assume that in areas with other cellulosic feedstocks (forest and agricultural residue), that the MSW would be used even if the MSW could not justify the installation of a plant on its own. Therefore, we estimated that urban waste could help contribute to the production of approximately 2.2 billion gallons of ethanol.[NNNNNN]

The results from the April 2008 version of the agricultural modeling (FASOM) suggested that corn stover will make up the majority of agricultural residues used by 2022 to meet the EISA cellulosic biofuel standard (approximately 83 million dry tons used to produce 7.8 billion gallons of cellulosic ethanol).[OOOOOO] Smaller contributions were expected to come from bagasse, which is a by-product from the production of sugarcane, (1.2 bgal ethanol) and sweet sorghum pulp (0.1 bgal ethanol). At the time of the proposal, FASOM was able to model agricultural residues but not forestry biomass as potential feedstocks. As a result, we had relied on the U.S. Forest Service for information on the forestry sector for our plant siting analysis.

Using the assumptions from FASOM on residue and ethanol yields, we determined if it is possible to site potential cellulosic plants based on the acres currently harvested. We identified that there are enough harvested acres to produce 7.8 Bgal of ethanol from corn stover by 2022 without having to rely on new lands. Therefore, the siting of many of the cellulosic facilities will likely be located where corn is typically grown today. See Table 1.8-18 for a summary of the

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[NNNNNN] Assuming approximately 90 gal/dry ton ethanol conversion yield; Note that this is slightly different from the 2.3 billion gallons of ethanol assumed in other analyses in this package.

[OOOOOO] Assuming 94 gal/dry ton ethanol conversion yield for corn stover in 2022 states producing corn stover, and their projected volume contribution to meeting the EISA cellulosic requirement by 2022.

### Table 1.8-18.
### Projected Ethanol Produced to Meet EISA in 2022 from Corn Stover (NPRM version for AQ Modeling)[pppppp]

| State | Total Harvested Acres (in 2022) | Total Residue Yield (tons/acre) | Total Residue Available (Million tons) | Residue Used (Million tons) | Percent Residue Used | Ethanol Produced (Million gallons) |
|---|---|---|---|---|---|---|
| Illinois | 12,994,100 | 5.43 | 71 | 15 | 21% | 1444 |
| Indiana | 6,209,463 | 5.58 | 35 | 10 | 29% | 922 |
| Iowa | 14,482,313 | 5.47 | 79 | 17 | 21% | 1557 |
| Kansas | 3,026,615 | 5.33 | 16 | 3 | 19% | 261 |
| Kentucky | 1,473,023 | 5.08 | 7 | 1 | 13% | 63 |
| Michigan | 2,238,321 | 4.30 | 10 | 3 | 31% | 246 |
| Minnesota | 7,509,658 | 5.37 | 40 | 8 | 20% | 750 |
| Missouri | 2,732,875 | 4.73 | 13 | 5 | 39% | 434 |
| Nebraska | 10,135,162 | 5.88 | 60 | 9 | 15% | 840 |
| Ohio | 3,712,612 | 4.91 | 18 | 5 | 27% | 453 |
| South Dakota | 4,268,425 | 4.01 | 17 | 4 | 23% | 350 |
| Wisconsin | 3,001,454 | 4.74 | 14 | 5 | 35% | 432 |
| Total | 71,784,020 | n/a | 380 | 82 | 22% | 7752 |

Sugarcane, on the other hand, is grown mainly in Florida, Louisiana, and Texas, although plans are underway to also grow sugarcane in California as well. See Section 1.1.1.2 of the RIA for more discussion on sugarcane ethanol produced in the U.S. If all the sugarcane acres harvested in the U.S. in 2007 were used to produce ethanol from the bagasse, using the assumptions from FASOM on residue and ethanol yields, only approximately 700 million gallons could be produced, see Table 1.8-19. FASOM, however, predicted that the production of 1.2 billion gallons of ethanol could be economically feasible from sugarcane bagasse. This means that between now and 2022, more sugarcane may be grown, allowing for more availability of bagasse in the future.

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[pppppp] Corn stover is given in dry tons/acre and assumes an ethanol yield of 94 gal/dry ton (this was updated in the final rule to 92.3 gal/dry ton based on NREL estimates); This table gives approximate averages by state based on our April 2008 version of the agricultural modeling, actual yields will vary greatly depending on specific soil type, slope, etc. The values above are calculated using the FASOM data outputs from April 2008 and thus are different from those found in other sections of this package which use more updated runs from 2009.

### Table 1.8-19.
### Projected Ethanol Produced to Meet EISA in 2022 from Sugarcane Bagasse

| State | Total Harvested Acres (in 2007) | Total Bagasse Yield (tons/acre) | Residue Used (Million tons) | Ethanol Produced (Million gallons) |
|---|---|---|---|---|
| Total | 810,800 | n/a | 10 | 707 |
| Florida | 382,000 | 14.71 | 6 | 389 |
| Louisiana | 389,600 | 10.25 | 4 | 277 |
| Texas | 39,200 | 15.23 | 1 | 41 |

Using FASOM, we analyzed the types of land likely to be supplanted by additional sugarcane acres in 2022 in the states of Florida, Louisiana, and Texas. In Florida, sugarcane crops appear to replace mainly corn, soy, and hay acres. In Louisiana, sugarcane crops appear to have replaced mainly corn, soy, wheat, sorghum, and hay acres. In Texas, sugarcane crops appear to have replaced mainly soy and sorghum crops. For these three states we gathered available data on corn, soy, wheat, and sorghum acres currently harvested by county (data on hay acres were unavailable and appeared to show small changes compared to corn and soy).[485] We then identified the top counties (in terms of acres available) in close proximity to each other that could potentially be converted from corn to sugarcane crops, soy to sugarcane, wheat to sugarcane, etc. in order to produce enough ethanol for half a billion gallons.

Sweet sorghum pulp is predicted to be used to produce approximately 0.1 billion gallons of ethanol. According to the National Agriculture and Statistics Service (NASS) of the Department of Agriculture, there is not current available data on sweet sorghum acres grown in the United States. Therefore, we used FASOM to predict the type of crops that sweet sorghum is mainly replacing, which is corn and soybeans. Similar to the analysis done for sugarcane, we identified the top counties (in terms of acres available) in close proximity to each other that could potentially be converted from corn to sweet sorghum crops and soy to sweet sorghum crops in order to produce enough ethanol for 0.1 billion gallons.

For forestry biomass, we utilized data provided by the U.S. Forest Service (biomass supply curves for various sources i.e., logging residues, other removal residues, thinnings from timberland, etc.). This information suggested that a large portion of forest material could be available for producing biofuels (excluding forest biomass material contained in national forests as required under the Act). See Section 1.1.2.3 for more information on forest residue feedstock availability. However, much of the forest material is in small pockets of forest which because of its regional low density, could not help to justify the establishment of a cellulosic ethanol plant. After conducting our availability analysis, we estimated that approximately 44 million dry tons of forest material could be used, which would make up approximately one fourth, or 3.8 billion gallons, of the 16 billion gallons of cellulosic biofuel required to meet EISA.

The April 2008 version of the FASOM results projected that 0.9 billion gallons of cellulosic ethanol from switchgrass is economically feasible by 2022. The majority of switchgrass is projected to likely be grown in Oklahoma, where the majority of acres are replacing wheat and hay. A smaller portion is expected to come from West Virginia and New Hampshire where hay is mainly replaced. Similar to the analysis done for sugarcane and sweet sorghum, we identified the top counties (in terms of acres available) in close proximity to each other that could potentially be converted from wheat to switchgrass or hay to switchgrass in order to produce enough ethanol for 0.9 billion gallons.

#### 1.8.1.4 Ethanol Usage Assumptions

To understand the impacts of increased ethanol use on air quality, we estimated where the ethanol might be used in the future under the RFS2 program. For this analysis, discussed in more detail in Chapter 3 of the RIA, we measured the impacts of 34.1 billion gallons of ethanol use in 2022, the total volume of ethanol assumed to be produced and consumed in the NPRM. For this analysis, we also applied NPRM assumptions with respect to FFV and E85 availability, described in more detail below.

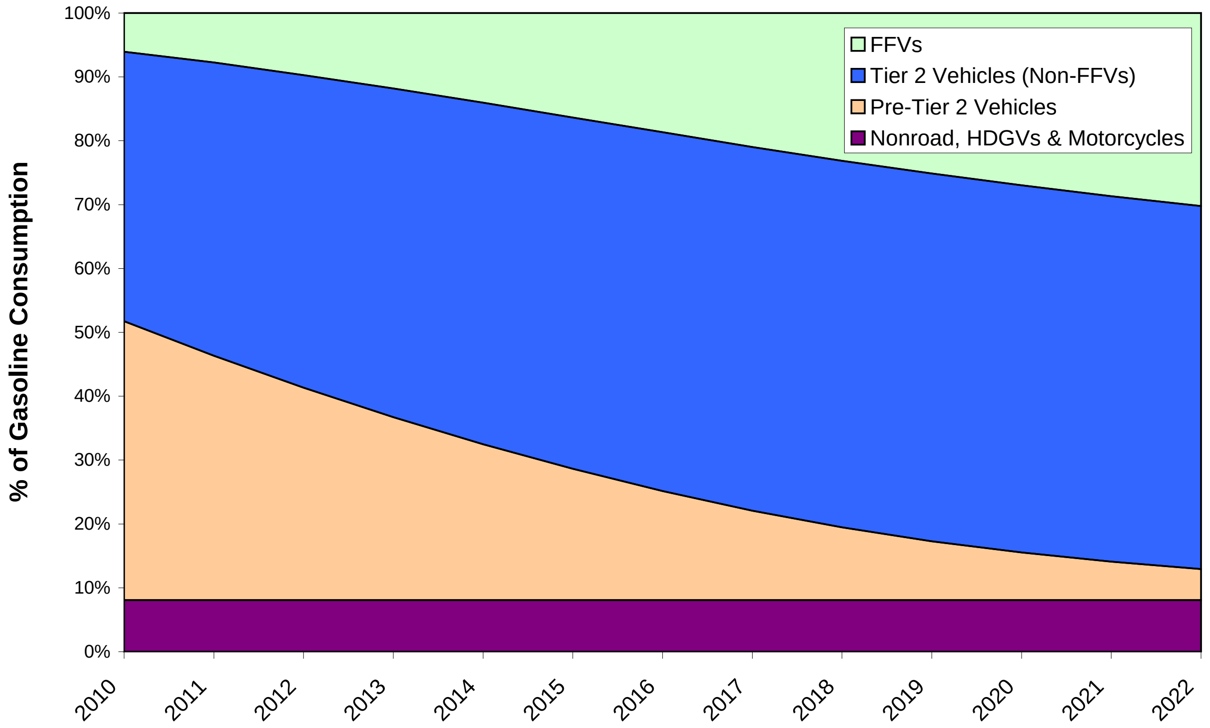
With respect to FFVs, we assumed that the Detroit 3 would follow through with their 50% by 2012 FFV commitment and the non-domestic automakers would follow suit and produce 25% FFVs by 2017. This corresponded to the primary Optimistic FFV Production Scenario outlined in the NPRM. The annual FFV sales by vehicle type are summarized in Table 1.8-20 below. For analysis purposes, we made the simplifying assumption that all FFVs would be distributed homogeneously and total vehicle sales would remain constant around 16 million units per year. This differs from vehicle assumptions made for the final rule, outlined in Section 1.7.1.2.

**Table 1.8-20.**
**Optimistic FFV Production Scenario – FFV Production Assumptions**

| | GM, Chrysler & Ford | | | Non-Domestic Automakers | | |
|---|---|---|---|---|---|---|
| **Year** | **Tot FFVs** | **FFV-Cars** | **FFV-Trucks** | **Tot FFVs** | **FFV-Cars** | **FFV-Trucks** |
| 2002 | 1,000,000 | 200,000 | 800,000 | 0 | 0 | 0 |
| 2003 | 1,000,000 | 200,000 | 800,000 | 0 | 0 | 0 |
| 2004 | 1,000,000 | 200,000 | 800,000 | 0 | 0 | 0 |
| 2005 | 1,000,000 | 200,000 | 800,000 | 0 | 0 | 0 |
| 2006 | 1,000,000 | 200,000 | 800,000 | 0 | 0 | 0 |
| 2007 | 1,000,000 | 200,000 | 800,000 | 0 | 0 | 0 |
| 2008 | 1,600,000 | 320,000 | 1,280,000 | 80,000 | 0 | 80,000 |
| 2009 | 2,200,000 | 440,000 | 1,760,000 | 160,000 | 0 | 160,000 |
| 2010 | 2,800,000 | 560,000 | 2,240,000 | 240,000 | 0 | 240,000 |
| 2011 | 3,400,000 | 680,000 | 2,720,000 | 320,000 | 0 | 320,000 |
| 2012 | 4,000,000 | 800,000 | 3,200,000 | 400,000 | 0 | 400,000 |
| 2013 | 4,000,000 | 800,000 | 3,200,000 | 720,000 | 0 | 720,000 |
| 2014 | 4,000,000 | 800,000 | 3,200,000 | 1,040,000 | 0 | 1,040,000 |
| 2015 | 4,000,000 | 800,000 | 3,200,000 | 1,360,000 | 0 | 1,360,000 |
| 2016 | 4,000,000 | 800,000 | 3,200,000 | 1,680,000 | 0 | 1,680,000 |
| 2017 | 4,000,000 | 800,000 | 3,200,000 | 2,000,000 | 0 | 2,000,000 |
| 2018 | 4,000,000 | 800,000 | 3,200,000 | 2,000,000 | 0 | 2,000,000 |
| 2019 | 4,000,000 | 800,000 | 3,200,000 | 2,000,000 | 0 | 2,000,000 |
| 2020 | 4,000,000 | 800,000 | 3,200,000 | 2,000,000 | 0 | 2,000,000 |
| 2021 | 4,000,000 | 800,000 | 3,200,000 | 2,000,000 | 0 | 2,000,000 |
| 2022 | 4,000,000 | 800,000 | 3,200,000 | 2,000,000 | 0 | 2,000,000 |

Based on these FFV production assumptions and forecasted vehicle phase-out, VMT, and fuel economy estimates provided by an earlier version of EPA’s MOVES Model, we calculated that the maximum percentage of fuel (gasoline/ethanol mix) that could feasibly be consumed by FFVs in 2022 would be about 30%. The resulting gasoline energy consumption by vehicle type under the Optimistic FFV Production Scenario is shown below in Figure 1.8-5. For analysis purposes, we assumed that the percentage of gasoline energy consumed by nonroad, heavy-duty gasoline vehicles (HDGVs), and motorcycles would be about 8% based on historical information provided by DOE.[486]

## Figure 1.8-5.
## Optimistic FFV Production Scenario - Gasoline Consumption by Vehicle Type

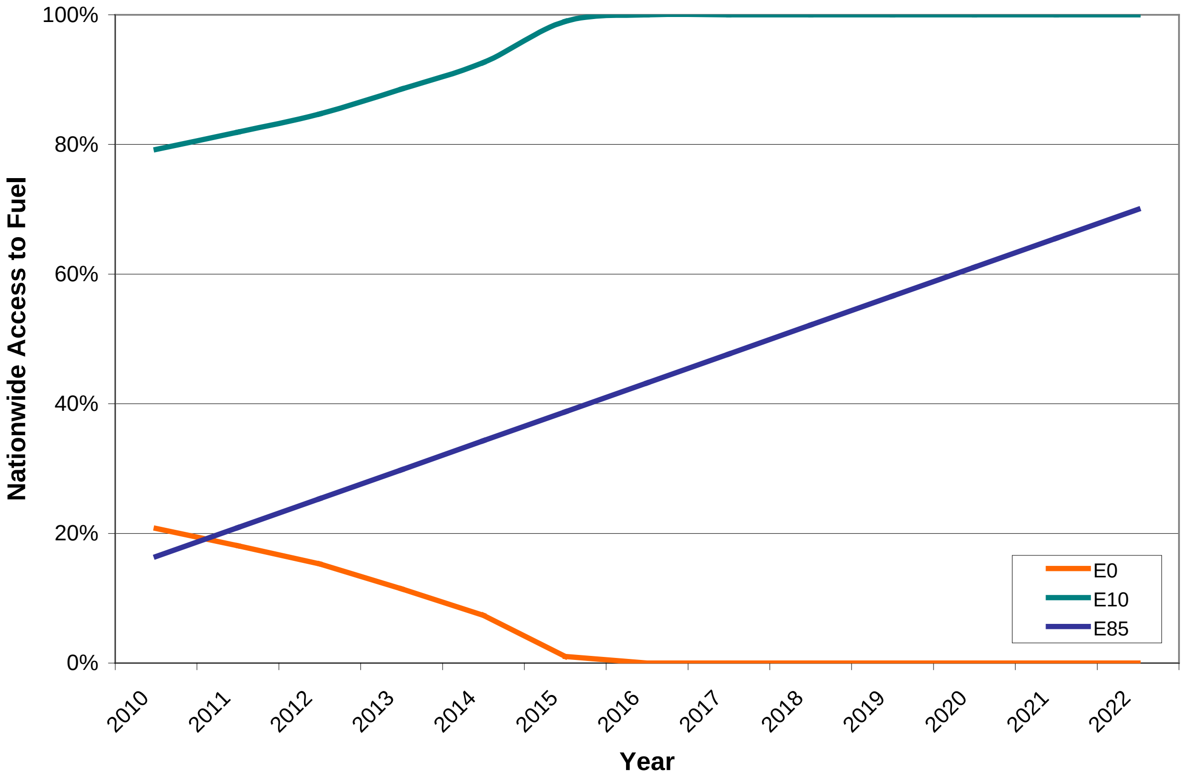


For the primary ethanol usage scenario analyzed in the NPRM and used for the AQ modeling work, we assumed practical, yet aggressive growth in E85 access. We considered the possibility that 70% of the nation could have reasonable one-in-four-station access to E85 by 2022. This is roughly equivalent to all urban areas in the United States offering E85 as explained in Section 1.7.3 of the RIA.

We are not concluding that E85 would only be offered in urban areas in the future. In fact, most E85 stations are currently located in the Midwest. However, we believe that this would be one possible way to provide 70% of the population with reasonable access to E85. From a fuel price standpoint, it makes sense that E85 might be offered in areas of the country with relatively high gasoline prices (e.g., RFG and low-RVP areas). Additionally, from an infrastructure cost standpoint, it makes sense that E85 might be offered in more populated metropolitan areas with high gasoline throughput. For more on fuel distribution logistics and costs, refer to Sections 1.6 and 4.2 of the RIA.

Assuming that reasonable E85 access grows linearly to 70% by 2022, we iteratively computed the corresponding nationwide E0 and E10 access assuming that a) each fuel retailer only carries one type of conventional gasoline (E0 or E10) and b) the nation does not exceed the RFS2 ethanol volume requirements analyzed for the NPRM. Under a very aggressive FFV production scenario, we estimate that E0 could theoretically remain in existence until 2016 as shown below in Figure 1.8-6. However, we anticipate that E10 will likely replace E0 sooner based on current market trends.

**Figure 1.8-6.**
**Assumed Phase-Out of E0 and Phase-In of E10 & E85**



To comply with the proposed RFS2 program and consume 34.1 billion gallons of ethanol by 2022, not only would we need more FFVs and more E85 retailers, we'll need to see a significant increase in FFV E85 refueling. Under the Optimistic FFV Production Scenario (assuming practical growth in E85 access), our analysis suggests that FFV owners with reasonable one-in-four access to E85 would need to fill up on it 74% of the time in 2022 - a significant increase from today's refueling frequency.

To estimate where E85 might be consumed under the proposed RFS2 program in 2022, we conducted a cost effectiveness study. For each area of the county, we began by looking at gasoline delivered prices. We started with state-level gasoline prices (excluding taxes) provided by EIA's Petroleum Marketing Annual 2006.[487] We relied on Table 31 for average gasoline prices, looked to Table 34 for RFG prices and back-calculated CG prices by applying the respective gasoline fuel volumes provided in Table 48. For states requiring 7 or 7.8-lb gasoline in the summertime, we applied PADD-average low-RVP gasoline production costs derived from the Mobile Source Air Toxics (MSAT) rule[488] to come up with the respective low-RVP and 9-lb conventional gasoline prices in these states. From there, we added in the corresponding gasoline taxes (state plus federal) according to the American Petroleum Institute (API).[489] This gave us the average retail cost of gasoline by state and fuel type.

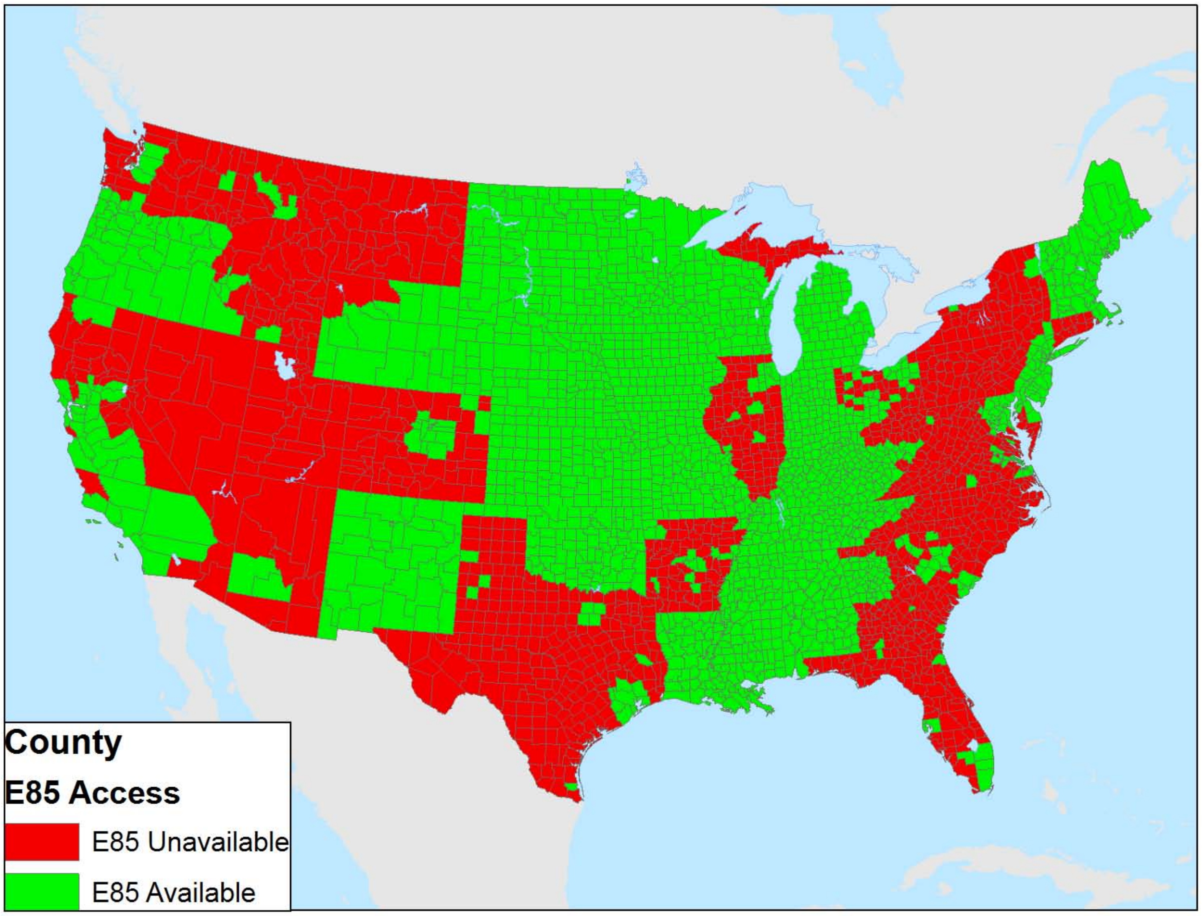
Next we converted the gasoline prices into competitive retail E85 prices by adjusting for the reduced energy density of E85, the increased refueling time, and E85's presumed limited availability in 2022. For a more on this general methodology, refer to Section 1.7.1.2.5 of the RIA. From there, we deducted fuel taxes (assumed to be the same as gasoline), backed out marketing costs and retail profits (assumed to be $0.10 per gallon) and subtracted the terminal-to-retail transportation costs (assumed to be $0.03) to arrive at the estimated retail value of E85, and ultimately, the retail value of ethanol.[QQQQQQ] Once we computed the retail value of ethanol, we compared it to the estimated ethanol delivered price (based on transportation costs presented in Section 4.2 of the proposal) to come up with the respective E85 profit margin.

To conclude, we assigned E85 to the areas of the county with the highest E85 profit margins, or in some cases, the least negative E85 profit margins until we arrived at approximately 34 billion gallons of ethanol in 2022. For a graphical representation of the areas of the country we assumed would receive/consume E85, refer to Figure 1.8-7.

---

[QQQQQQ] For analysis purposes we assumed that E85 was taxed at the same rate as gasoline. We acknowledge that a number of states currently have reduced excise taxes or excise tax exemptions for E85. However, the extent of the tax breaks is somewhat unknown and the potential that these tax breaks will exist in the future is uncertain.

**Figure 1.8-7**
**Projected E85 Availability in 2022 Under RFS2**



## 1.8.2 Biodiesel & Renewable Diesel Inputs

### 1.8.2.1 Upstream Production Inputs

In order to generate county-level emissions inputs for the control case, we needed projected locations of biodiesel production facilities. This task was complicated by the fact that the current aggregate industry production capacity is significantly larger than the volume of biodiesel projected to be consumed in our primary control case, a fact which suggests the industry may downsize in the long term.

We developed a method to determine where biodiesel producers were most likely to remain based on state incentives to biodiesel producers and for biodiesel sales or use. Data on state incentives was taken from an online database maintained by the Department of Energy Office of Energy Efficiency and Renewable Energy.[490] Two other criteria we considered were the BQ-9000 status of individual plants and their ability to process multiple feedstock types, as listed by the National Biodiesel Board. [491] Based the volume of the primary control case, assuming a capacity utilization factor of approximately 80%, a list of plants for the 2022 scenarios was generated choosing first from those plants with most favorable status of the four criteria and working downward. We projected that a number of very small plants processing waste greases/fats would continue to operate based on local market niches regardless of these criteria. In an effort to be realistic in this forecast, other practical considerations were made, such as avoiding siting several plants in the same state (except in the Midwest).

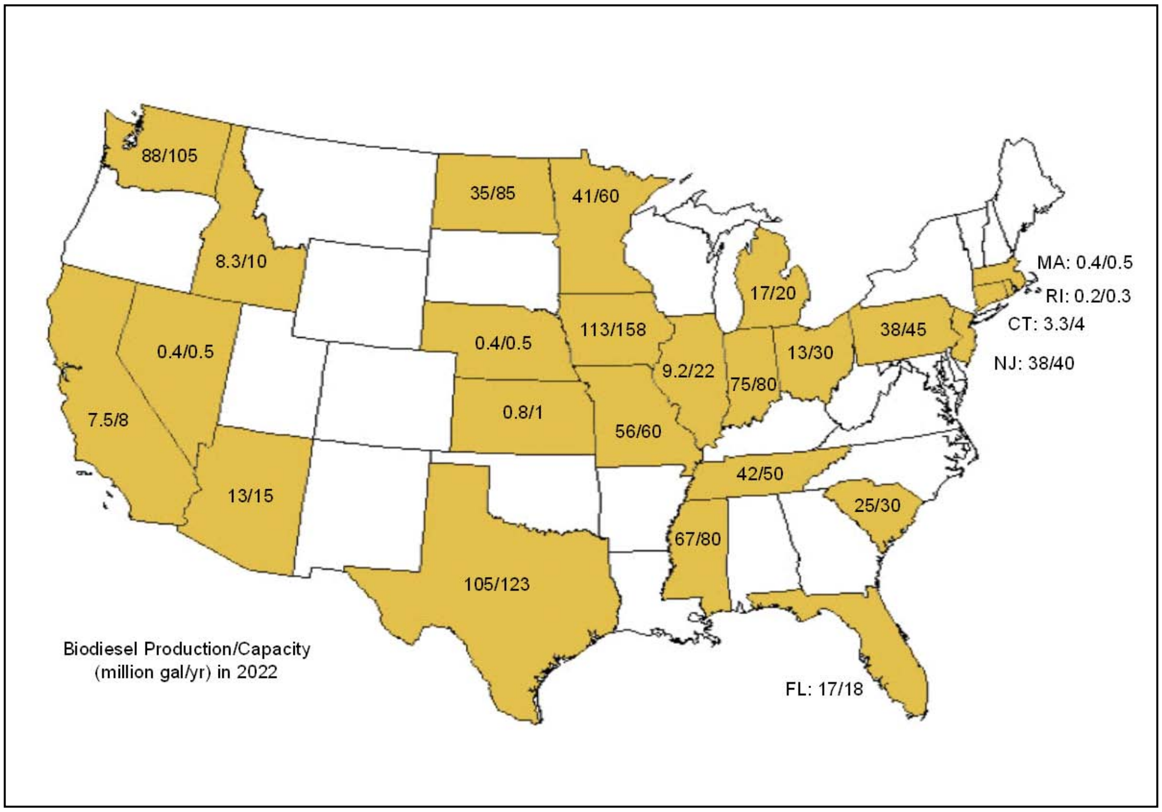
We project that between now and 2022 plants will continue to compete and consolidate to make fewer plants of larger size. During this period most plants will have added the pre-treatment and feedstock segregation capacity to process any mix of feedstock types available in their area.

From the projected list of plant locations, emission quantities were generated for each county based on each plant's biodiesel production rate. Spreadsheets showing lists of the representative plants and their emission factors as input in the inventory and air quality models can be found in the docket. This information is summarized here in Table 1.8-21 and Figure 1.8-9.

**Table 1.8-50. Summary of biodiesel industry and forecast used for AQM.**[492]

| | **2008** | **2022** |
|---|---|---|
| Total production capacity on-line (million gal/yr) | 2,610 | 1,050 |
| Number of operating plants | 176 | 35 |
| Median plant size (million gal/yr) | 5 | 30 |
| Total biodiesel production (million gal) | 700 | 810 |
| Average capacity factor | 0.27 | 0.77 |

**Figure 1.5-18. Biodiesel industry forecast for 2022**



### 1.8.2.2 Downstream Consumption Inputs

Biodiesel, like ethanol, is generally blended at the end of the distribution chain, just before delivery to retail outlets. Because of its chemical properties, it is not currently considered fungible with diesel fuel, and thus its blend level in fuels offered for sale is typically deliberate and explicit. Renewable diesel, on the other hand, is a fuel or hydrocarbon blendstock which can be blended into fungible fuel at any point in the distribution system, such that the blend level at the final point of use is not typically of concern and, in fact, would probably be difficult to determine. Because of its nature, and the relatively small volumes we are projecting (less than 0.5 billion gallons per year), we have not analyzed distribution or use impacts for renewable diesel. The remainder of this section addresses biodiesel use.

Vehicle and engine manufacturers recognize biodiesel as a lubricity improver at low levels, something that is useful with ultra-low sulfur diesel fuel now phasing in across the country. Therefore, most state that their products are compatible with blends up to 5%, and a few suggest blends up to 20% can be used without problems. Therefore, our analysis assumes blends up to 5% can find widespread use.

In order to conduct our distribution and emissions analyses, we needed to forecast approximate volumes of biodiesel to be used in each state. We considered transportation diesel fuel and home heating oil as the primary uses for biodiesel. For transportation fuel estimates, we assumed that biodiesel would be preferentially used in states that have blend mandates or significant per-gallon incentives. Table 1.8-21 shows the states with such mandates and incentives on record as of summer 2008, as well as the associated potential biodiesel volumes based on 2005 diesel fuel use.[493] State-level forecasts were not available for transportation fuel use, thus the reliance on historical data for this estimate.

**Table 1.8-21.**
**State biodiesel incentives as of summer 2008 and potential volumes based on 2005 data.[494]**

| State | Incentive or mandate | Diesel fuel use (million gal/yr) | 2% biodiesel (million gal/yr) | 5% biodiesel (million gal/yr) |
|---|---|---:|---:|---:|
| IL | per-gallon tax incentive(s) for B11+, state fleet requirement | 1,660 | 33.2 | |
| KS | per-gallon tax incentive(s) for B2+ | 816 | 16.3 | |
| LA | B2 mandate with some conditions | 1,734 | 34.7 | |
| MA | B2 mandate, increasing to B15 with some conditions | 491 | | 24.5 |
| MI | per-gallon tax incentive(s) for B5+ | 1,071 | | 53.5 |
| MN | B2 mandate; state fleet requirement | 999 | 20.0 | |
| NC | per-gallon tax incentive(s), B2 school bus requirement | 1,234 | 24.7 | |
| ND | per-gallon tax incentive(s) | 358 | 7.2 | |
| NE | per-gallon tax incentive(s) | 547 | 10.9 | |
| NM | B5 mandate with some conditions | 475 | | 23.7 |
| OH | per-gallon tax incentive(s) | 1,556 | 31.1 | |
| OR | B2 mandate, increasing to B5 with some conditions | 738 | | 36.9 |
| SC | per-gallon tax incentive(s) | 764 | 15.3 | |
| SD | per-gallon tax incentive(s) | 263 | 5.3 | |
| TX | per-gallon tax incentive(s) | 5,339 | 106.8 | |
| WA | B2 mandate, increasing to B5 with some conditions | 1,230 | 24.6 | |
| | | | **Total biodiesel** | **468.7** |

Table 1.8-22 shows home heating oil use in 2005. We estimate potential biodiesel use in heating oil at 89 million gallons per year based on a 2% blend in all heating oil north of the Washington, DC, area (i.e., PADD 1A and 1B). This area was chosen because it is where the majority of heating oil is used, and should have adequate biodiesel access from New Jersey, Pennsylvania, and Connecticut in our forecasted production scenarios. To the extent that heating oil use declines over time, the blend levels may increase in some areas or in the shoulder seasons, such that the total biodiesel volume used in this market would not decline drastically.

**Table 1.8-22.**
**Potential biodiesel use in heating oil based on 2005 data.**[495]

| Area | Heating oil (million gal/yr) | 2% biodiesel (million gal/yr) | Volume Used (million gal/yr) |
|---|---:|---:|---:|
| U.S. | 5,565,489 | 111.3 | |
| PADD 1 | 4,759,198 | 95.2 | |
| PADD 1A | 1,923,405 | 38.5 | 38.5 |
| CT | 545,910 | 10.9 | |
| ME | 308,464 | 6.2 | |
| MA | 674,324 | 13.5 | |
| NH | 175,484 | 3.5 | |
| RI | 136,618 | 2.7 | |
| VT | 82,604 | 1.7 | |
| PADD 1B | 2,529,106 | 50.6 | 50.6 |
| DE | 33,221 | 0.7 | |
| DC | 12,832 | 0.3 | |
| MD | 149,919 | 3.0 | |
| NJ | 322,088 | 6.4 | |
| NY | 1,282,899 | 25.7 | |
| PA | 728,147 | 14.6 | |
| PADD 1C | 306,687 | 6.1 | |
| FL | 3,608 | 0.1 | |
| GA | 1,520 | 0.0 | |
| NC | 81,528 | 1.6 | |
| SC | 8,810 | 0.2 | |
| VA | 197,255 | 3.9 | |
| WV | 13,966 | 0.3 | |
| | | **Total used for biodiesel in heating oil** | **89.1** |

Combining these volumes gives 558 million gallons per year potential biodiesel consumption, leaving approximately 250 million gallons to be sold in blends above the projected levels shown here, or in states not included here. For more on biodiesel-related distribution issues and costs, refer to Section 4.2.2.2.

# Chapter 2: Lifecycle GHG Analysis

## 2.1 Chapter Overview

This chapter describes each component of the analysis undertaken by EPA as part of the RFS2 rulemaking to determine lifecycle GHG emissions impacts for renewable and petroleum-based transportation fuels. The chapter is organized as follows:

- **Section 2.2** provides background about lifecycle analysis for RFS2 and key modeling updates EPA has made since the proposed rule.
- **Section 2.3** lays out the goals and scope of our analysis.
- **Section 2.4** provides a detailed explanation of each component in EPA's lifecycle analysis of renewable fuels.
    - **Section 2.4.1** summarizes the Agency's overall biofuel modeling approach.
    - **Section 2.4.2** focuses on domestic agricultural sector GHG emissions impacts, including our evaluation of changes in agricultural inputs and livestock production.
    - **Section 2.4.3** discusses international agricultural impacts.
    - **Section 2.4.4** explains EPA's assessment of GHG emissions impacts from biofuel-induced domestic and international land conversions, including our quantification of uncertainty in international land conversion GHG emissions impacts.
    - **Section 2.4.5** describes our accounting for lifecycle GHG emissions over time.
    - **Section 2.4.6** explains EPA's analysis of biofuel feedstock transport.
    - **Section 2.4.7** discusses energy use and GHG emissions from biofuel processing.
    - **Section 2.4.8** includes our updated analysis of fuel transport and distribution.
    - **Section 2.4.9** covers renewable fuel tailpipe emissions.
    - **Section 2.4.10** discusses other potential indirect impacts from biofuel production.
    - **Section 2.4.11** describes other modeling approaches that EPA considered for lifecycle GHG analysis.
- **Section 2.5** presents EPA's analysis of baseline gasoline and diesel lifecycle GHG emissions for comparison with biofuels.
- **Section 2.6** discusses the fuel-specific lifecycle GHG emissions results, including sensitivity analyses.
- **Section 2.7** includes our analysis of the overall GHG impacts of the rulemaking volumes.
- **Section 2.8** concludes the chapter with a discussion of the effects of the RFS2 on global temperature and sea level.

## 2.2 Background for Estimating Fuel Lifecycle Greenhouse Gas Emissions

### 2.2.1 Lifecycle Analysis for the RFS2 Proposal

Lifecycle modeling of transportation fuels, often referred to as fuel cycle or well-to-wheel analysis, assesses the net impacts of a fuel throughout each stage of its production and use including production / extraction of the feedstock, feedstock transportation, fuel production, fuel transportation and distribution, and tailpipe emissions. Use of a lifecycle approach to analyze different transportation fuels requires modeling and evaluation of many different input factors.

Lifecycle assessments can be divided into two major methodological categories: attributional and consequential.[496]

An attributional approach to GHG emissions accounting in products provides information about the GHG emitted directly by a product and its life cycle. The product system includes processes that are directly linked to the product by material, energy flows or services following a supply-chain logic.

A consequential approach to GHG emissions accounting in products provides information about the GHG emitted, directly or indirectly, as a consequence of changes in demand for the product. This approach typically describes changes in GHG emissions levels from affected processes, which are identified by linking causes with effects.

The definition of lifecycle greenhouse gas emissions established by Congress states that:

> *The term 'lifecycle greenhouse gas emissions' means the aggregate quantity of greenhouse gas emissions (including direct emissions and significant indirect emissions such as significant emissions from land use changes), as determined by the Administrator, related to the full fuel lifecycle, including all stages of fuel and feedstock production and distribution, from feedstock generation or extraction through the distribution and delivery and use of the finished fuel to the ultimate consumer, where the mass values for all greenhouse gases are adjusted to account for their relative global warming potential.* [497]

This definition and specifically the clause *"(including direct emissions and significant indirect emissions such as significant emissions from land use changes)"* requires the Agency to consider a consequential lifecycle analyses and to develop a methodology that accounts for all of the important factors that may significantly influence this assessment, including the secondary or indirect impacts of expanded biofuels use.

Furthermore, independent of the statutory language the Agency believes it is important to include secondary, indirect, or consequential impacts of biofuel use, specifically:

- Capturing secondary market driven agricultural sector impacts, such as changes in other crop patterns and livestock production as a response to changing prices in biofuel feedstocks.

- Production of co-products from biofuel production requires some type of allocation, either splitting emissions of fuel production between fuel and co-products or examining the use of co-products in other markets. For example in the case of corn

> ethanol, the co-product of ethanol production is a feed product that is assumed to replace the use of corn and soybean meal. Therefore, the emissions of producing an equivalent amount of corn and soybean meal to these co-products are subtracted from the lifecycle assessment. This requires modeling of the co-product economic markets.
>
> - To the extent that they are included in attributional lifecycle analyses, land use impacts are typically confined to direct impacts, e.g., land converted to produce corn directly used for ethanol production. This does not capture effects of land converted to produce crops that are indirectly impacted by increased biofuel production. One specific example of this is increased corn ethanol production in the U.S. could lead to decreased crop exports resulting in increased crop production and land use impacts internationally. Another example is corn production increases resulting in less rice production and lower CH4 emissions.
>
> - Consideration of specific policies and interaction between different fuel volumes could have very distinct impacts especially in the agricultural sector.

The lifecycle methodology developed for the RFS2 rulemaking analysis included the use of economic models to perform a consequential type of lifecycle analysis.

The consequential approach of incorporating economic models into a lifecycle assessment is not a new concept. Most notably the Economic Input-Output Lifecycle Assessment (EIO-LCA) method has been employed in the past. The EIO-LCA method estimates the materials and energy resources required for, and the environmental emissions resulting from, activities in the overall economy. The EIO-LCA method was theorized and developed by economist Wassily Leontief in the 1970s based on his earlier input-output work from the 1930s for which he received the Nobel Prize in Economics. Researchers at the Green Design Institute of Carnegie Mellon University operationalized this method in the mid-1990s, once sufficient computing power was widely available to perform the large-scale matrix manipulations required in real-time. This work relies on static input-output tables of the U.S. economy to determine the full economy wide impacts of producing a product or service.

Mark Delucchi at the Institute of Transportation Studies of the University of California Davis has developed the Lifecycle Emissions Model (LEM) that looks at transportation fuels. He has also highlighted the need to look at market impacts when considering biofuel production and specifically to consider land use changes.[498] There have also been several studies examining the consequential or economic-based life cycle assessment including several focusing on the agricultural sector.

Currently, no single model captures all of the complex interactions associated with estimating lifecycle GHG emissions for biofuels, taking into account the "significant indirect emissions such as significant emissions from land use change" required by EISA. For example, some lifecycle analysis tools typically used in the past focused on process modeling—the energy and resultant emissions associated with the direct production of a fuel at a petroleum refinery or biofuel production facility. But this is only one component in the production of the fuel. Clearly in the case of biofuels, impacts from and on the agricultural sector are important, because this sector produces feedstock for biofuel production. Commercial agricultural operations make many of their decisions based on an economic assessment of profit maximization. Assessment of the interactions throughout the agricultural sector requires an analysis of the commodity markets using economic models. However, existing economy wide general equilibrium economic models are not detailed enough, on their own, to capture the specific agricultural sector interactions critical to our analysis (e.g., changes in acres by crop type) and would not provide the types of outputs needed for a thorough GHG analysis. As a result, EPA has used a set of tools that are best suited for each specific component of the analysis to create a more comprehensive estimate of GHG emissions. Where no direct links between the different models exist, specific components and outputs of each are used and combined to provide an analytical framework and the composite lifecycle assessment results.

To estimate the changes in the domestic agricultural sector (e.g., changes in crop acres resulting from increased demand for biofuel feedstock or changes in the number of livestock due to higher corn prices) and their associated emissions, we used the Forestry and Agricultural Sector Optimization Model (FASOM), developed by Texas A&M University and others. FASOM is a partial equilibrium economic model of the U.S. forest and agricultural sectors. EPA selected the FASOM model for this analysis for several reasons. FASOM is a comprehensive forestry and agricultural sector model that tracks over 2,000 production possibilities for field crops, livestock, and biofuels for private lands in the contiguous United States. It accounts for changes in CO2, methane, and N2O from most agricultural activities and tracks carbon sequestration and carbon losses over time. Another advantage of FASOM is that it captures the impacts of all crop production, not just biofuel feedstock. Thus, as compared to some earlier assessments of lifecycle emission, using FASOM allows us to determine secondary agricultural sector impacts, such as crop shifting and reduced demand due to higher prices. It also captures changes in the livestock market (e.g., smaller herd sizes that result from higher feed costs) and U.S. export changes. FASOM also has been used by EPA to consider U.S. forest and agricultural sector GHG mitigation options.[499]

The output of the FASOM analysis includes changes in total domestic agricultural sector fertilizer and energy use. These are calculated based on the inputs required for all the different crops modeled and changes in the amounts of the different crops produced due to increased biofuel production. FASOM output also includes changes in the number and type of livestock produced. These changes are due to the changes in animal feed prices and make-up due to the increase in biofuel production. The FASOM output changes in fertilizer, energy use, and livestock are combined with GHG emission factors from those sources to generate biofuel lifecycle impacts. The GHG emission factors for fuel and fertilizer production come from the Greenhouse gases, Regulated Emissions, and Energy use in Transportation (GREET) spreadsheet analysis tool developed by Argonne National Laboratories, and livestock GHG emission factors are from IPCC guidance.

GREET includes the GHG emissions associated with the production and combustion of fossil fuels (diesel fuel, gasoline, natural gas, coal, etc.). GREET also estimates the GHG emissions associated with electricity production required for agriculture and biofuel production. For the agricultural sector, we also relied upon GREET to provide GHG emissions associated with the production and transport of agricultural inputs such as fertilizer, herbicides, pesticides, etc. GREET has been under development for several years and has undergone extensive peer review through multiple updates. Of the available data sources of information on lifecycle GHG emissions of fossil energy and agricultural sector inputs consumed, we believe that GREET offers the most comprehensive treatment of emissions from the covered sources. GREET version 1.8c was the primary version used in this analysis.

To estimate the domestic impacts of N2O emissions from fertilizer application, we used the CENTURY and DAYCENT models, developed by Colorado State University. The DAYCENT model simulates plant-soil systems and is capable of simulating detailed daily soil water and temperature dynamics and trace gas fluxes (CH4, N2O, NOx and N2). The CENTURY model is a generalized plant-soil ecosystem model that simulates plant production, soil carbon dynamics, soil nutrient dynamics, and soil water and temperature. Model results for N2O emissions from different crop and land use changes were combined with FASOM output to generate overall domestic N2O emissions.

FASOM output also provides changes in total land use required for agriculture and land use shifting between crops, and interactions with pasture, and forestry. This output is combined with emission factors from land use change to generate domestic land use change GHG emissions from increased biofuel production.

To estimate the impacts of biofuels feedstock production on international agricultural and livestock production, we used the integrated Food and Agricultural Policy and Research Institute international models, as maintained by the Center for Agricultural and Rural Development (FAPRI-CARD) at Iowa State University. These models capture the biological, technical, and economic relationships among key variables within a particular commodity and across commodities. FAPRI-CARD is a worldwide agricultural sector economic model that was run by the Center for Agricultural and Rural Development (CARD) at Iowa State University on behalf of EPA. The FAPRI models have been previously employed to examine the impacts of World Trade Organization proposals, changes in the European Union's Common Agricultural Policy, analyze farm bill proposals since 1984, and evaluate the impact of biofuel development in the United States. In addition, the FAPRI models have been used by the USDA Office of Chief Economist, Congress, and the World Bank to examine agricultural impacts from government policy changes, market developments, and land use shifts.

The output of the FAPRI-CARD model included changes in crop acres and livestock production by type and by country globally. Unlike FASOM, the FAPRI-CARD output did not include changes in fertilizer or energy use or have land type interactions built in. These were developed outside the FAPRI-CARD model and combined with the FAPRI-CARD output to generate GHG emission impacts.

Crop input data by crop and country were developed and combined with the FAPRI-CARD output crop acreage change data to generate overall changes in fertilizer and energy use. These fertilizer and energy changes along with the FAPRI-CARD output livestock changes were then converted to GHG emissions based on the same basic approach used for domestic sources, which involves combining with emission factors from GREET and IPCC.

The FAPRI-CARD model does predict how much crop land will change in other countries but does not predict what type of land such as forest or pasture will be affected. We used data analyses provided by Winrock International to estimate what land types will be converted into crop land in each country and the GHG emissions associated with the land conversions. Working with Winrock, we used recent satellite data to analyze recent land use changes around the world that have resulted from the social, economic, and political forces that drive land use. In our assessment, we are assuming that these recent drivers of land use change will remain in relative affect through our 2022 modeling time frame such that the recent trends in land use change are indicative of land use changes likely to result in 2022 due to biofuel production. We combined the recent land use change patterns with various estimates of carbon stocks associated with different types of land at the state level. This international land use assessment is an important consideration in our lifecycle GHG assessment and is explained in more detail later in Section 2.4.4 in this chapter.

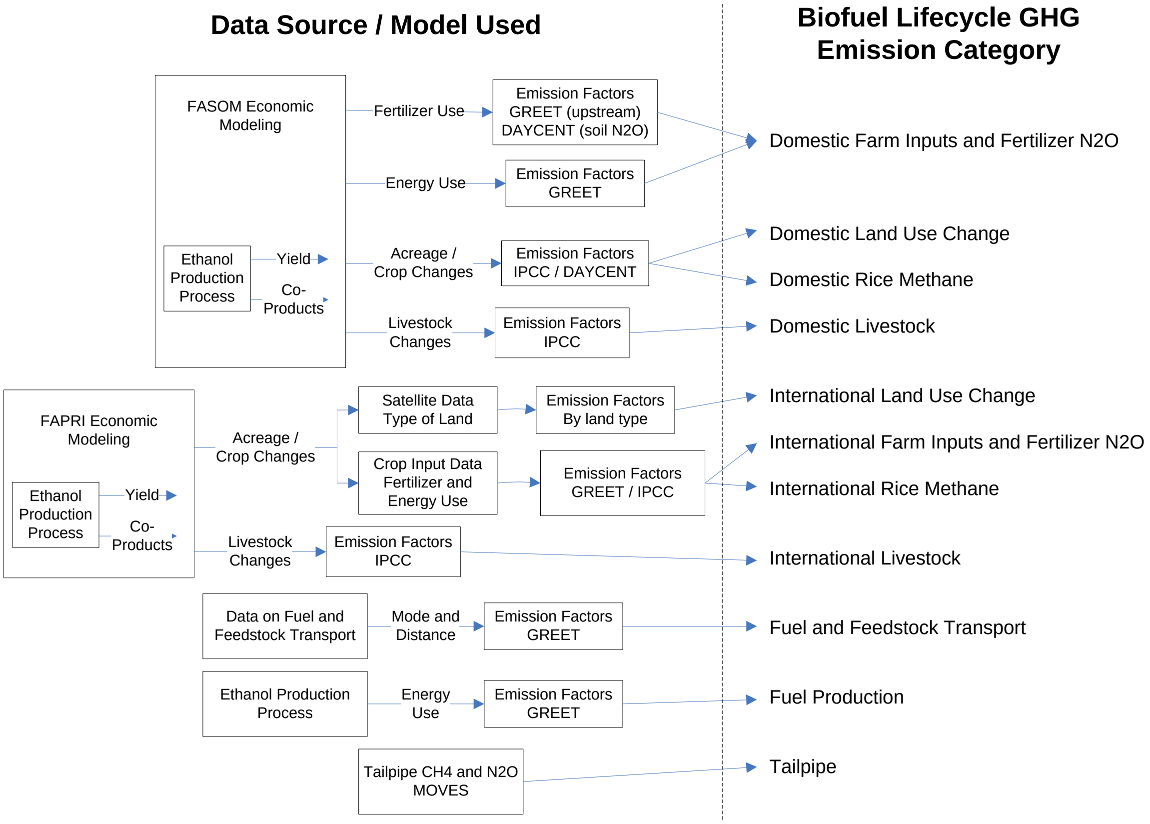
Additional modeling and data sources used to determine the GHG emissions of other stages in the biofuel lifecycle include studies and data on the distance and modes of transport needed to ship feedstocks from the field to the biofuel processing facility and the finished biofuel from the facility to end use. These distances and modes are used to develop the amount and type of energy used for transport which are combined with GREET factors to generate GHG emissions.

We also calculate energy use needed in the biofuel processing facility from industry sources, reports, and process modeling. This energy use is combined with emissions factors from GREET to develop GHG impacts of the biofuel production process

To test the robustness of the FASOM, FAPRI-CARD and Winrock results, we also examined biofuel land use change impacts with the Global Trade Analysis Project (GTAP) model, a multi-region, multi-sector, computable general equilibrium model that estimates changes in world agricultural production. Maintained through Purdue University, GTAP projects international land use change based on the economics of land conversion, rather than using the historical data approach applied by FAPRI-CARD/Winrock. GTAP is designed to project changes in international land use as a result of the change in U.S. biofuel policies, based on the relative land use values of cropland, forest, and pastureland. The GTAP design has the advantage of explicitly modeling the competition between different land types due to a change in policy. As further discussed in Section 2.4.11, the GTAP model results were generally consistent with our FAPRI-CARD/satellite data analysis, in particular supporting the significant impact on international land use.

Figure 2.2-1 graphically shows the different models used and what parts of the lifecycle they are used to represent.

**Figure 2.2-1 System Boundaries and Models Used**



## 2.2.2 Updates for this Final Rulemaking

Throughout the development of EPA's lifecycle analysis, the Agency has employed a collaborative, transparent, and science-based approach. EPA's lifecycle methodology, as developed for the RFS2 proposal, required breaking new scientific ground and using analytical tools in new ways. The work was generally recognized as state of the art and an advance in lifecycle modeling, specifically regarding the indirect impacts of biofuels.

However, the complexity and uncertainty inherent in this work made it extremely important that we seek the advice and input of a broad group of experts and stakeholders. In order to maximize stakeholder outreach opportunities, the comment period for the proposed rule was extended to 120 days. In addition to this formal comment period, EPA made multiple efforts to solicit public and expert feedback on our approach. Beginning early in the NPRM process and continuing throughout the development of this final rule, EPA held hundreds of meetings with stakeholders, including government, academia, industry, and non-profit organizations, to gather expert technical input. Our work was also informed heavily by consultation with other federal agencies. For example, we have relied on the expert advice of USDA and DOE, as well as incorporating the most recent inputs and models provided by these Agencies. Dialogue with the State of California and the European Union on their parallel, on-going efforts in GHG lifecycle analysis also helped inform EPA's methodology. As described below, formal technical exchanges and an independent, formal peer review of the methodology were also significant components of the Agency's outreach. A key result of our outreach effort has been awareness of new studies and data that have been incorporated into our final rule analysis.

Technology Exchanges: Immediately following publication of the proposed rule, EPA held a two-day public workshop focused specifically on lifecycle analysis to assure full understanding of the analyses conducted, the issues addressed, and the options discussed. The workshop featured EPA presentations on each component of the methodology as well as presentations and discussions by stakeholders from the renewable fuel community, federal agencies, universities, and environmental groups. The Agency also took advantage of opportunities to meet in the field with key, affected stakeholders. For example, the Agency was able to twice participate in meetings and tours in Iowa hosted by the local renewable fuel and agricultural community. As described in this section, one of the many outcomes of these meetings was an improved understanding of agricultural and biofuel production practices.

As indicated in the proposal, our lifecycle results were particularly impacted by assumptions about land use patterns and emissions in Brazil. During the public comment process we were able to update and refine these assumptions, including the incorporation of new, improved sources of data based on Brazil-specific data and programs. In addition, the Agency received more recent trends on Brazilian crop productivity, areas of crop expansion, and regional differences in costs of crop production and land availability. Lastly, we received new information on the effectiveness of current efforts to curb deforestation allowing the Agency to better predict this impact through 2022.

Peer Review: To ensure the Agency made its decisions for this final rule on the best science available, EPA conducted a formal, independent peer review of key components of the analysis. The reviews were conducted following the Office of Management and Budget's peer review guidance that ensures consistent, independent government-wide implementation of peer review, and according to EPA's longstanding and rigorous peer review policies. In accordance with these guidelines, EPA used independent, third-party contractors to select highly qualified peer reviewers. The reviewers selected are leading experts in their respective fields, including lifecycle assessment, economic modeling, remote sensing imagery, biofuel technologies, soil science, agricultural economics, and climate science. They were asked to evaluate four key components of EPA's methodology: (1) land use modeling, specifically the use of satellite data and EPA's proposed land conversion GHG emission factors; (2) methods to account for the variable timing of GHG emissions; (3) GHG emissions from foreign crop production (both the modeling and data used); and (4) how the models EPA relied upon are used together to provide overall lifecycle estimates. The full peer review records, including all of the charge questions and peer reviewer responses, are available in the public docket for this rulemaking.

The advice and information received through this peer review are reflected throughout this chapter. The reviewers also provided recommendations that have helped to inform the larger methodological decisions presented in this final rule. For example, the reviewers in general supported the importance of assessing indirect land use change and determined that in general EPA used the best available tools and approaches for this work. However, the review also recognized that no existing model comprehensively simulates the direct and indirect effects of biofuel production both domestically and internationally, and therefore model development is still evolving. The uncertainty associated with estimating indirect impacts and the difficulty in developing precise results also were reflected in the comments. In the long term, this peer review will help focus EPA's ongoing lifecycle analysis work as well as our future interactions with the National Academy of Science and other experts.

Altogether, the many and extensive public comments we received to the rule docket, the numerous meetings, workshops and technical exchanges, and the scientific peer review have all been instrumental to EPA's ability to advance our analysis between proposal and final and to develop the methodological and regulatory approach described in this section.

Based on peer review results as well as other comments received we have made several updates to our modeling since the NPRM analysis as shown in Table 2.2-1.

### Table 2.2-1. Key Lifecycle Modeling Updates

| Update | Source |
|---|---|
| Updates to Domestic Agricultural Sector Modeling: | |
| • Incorporated the FASOM forestry module | • Updated FASOM Forestry component |
| • Added new land classifications: cropland, cropland-pasture, rangeland, forest-pasture, forest, CRP, developed land | • U.S. land cover databases |
| • Reflected new data on projected switchgrass yields | • New data from PNNL on switchgrass yields |
| • Updated $N_2O$ / soil carbon emissions factors | • DAYCENT/CENTURY model updates by Colorado State University |
| • Updated emission factors for farm input production | • New version of GREET (version 1.8c) |
| Updates to International Agricultural Sector Modeling: | |
| • Incorporated a Brazil module into the international model framework<br>o Regional crop and pasture modeling | • FAPRI-CARD Brazil Module[RRRRRR] |
| • Added price induced yield changes (e.g., long term elasticity for the Corn Belt in the U.S. 0.07) | • FAPRI-CARD 2010 U.S. And World Agricultural Outlook |
| • Updated international agricultural GHG emission estimates | • International Fertilizer Industry Assoc. (2009)[500] and pesticide consumption from FAOStat[501] |
| • Updated Brazil sugarcane production based on recent studies | • Macedo (2008)[502] |
| Updates to Biofuel Processing in Both Domestic and International Agricultural Sector Modeling: | |
| • Built in corn fractionation pathways (with co-product markets, etc.) | • USDA |
| • Adjusted DGS co-product replacement rates<br>o Reflected studies that indicate more efficient use of co-product | • Empirical studies by Argonne Laboratory and University of Minnesota: Arora, Wu and Wang (2008)[503] and Shurson (2009)[504] |
| • Added biodiesel glycerin co-product credit | • Based on data from NBB and GREET |
| • Updated process energy use | • New studies by USDA[505], NREL[506,507,508] and Energy Resources Center[509] |
| Updates to Land Use Change Modeling: | |
| • Used more recent / longer time coverage / higher resolution satellite data - 2001-2007 | • MODIS V5 (2009)[510] |
| • Augmented satellite data with region specific data where available (e.g., data from Brazil on pasture intensification) | • FAPRI-CARD Brazil module |
| • New soil carbon data | • Harmonized World Soil Database (2009)[511] |
| • New studies monitoring long-term forest growth rates | • Lewis et al. (2009)[512] and Phillips et al. (2008)[513] |
| Petroleum Baseline Updates: | |
| • Updated 2005 petroleum baseline | • DOE/NETL (2009)[514] |

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[RRRRRR] Iowa State University working with Brazilian experts developed this module which has been incorporated into the FAPRI-CARD 2010 U.S. And World Agricultural Outlook, released date early 2010

Furthermore, in the proposal, we asked for comment on whether and how to conduct an uncertainty analysis to help quantify the magnitude of this uncertainty and its relative impact on the resulting lifecycle emissions estimates. The results of the peer review, and the feedback we have received from the comment process, supported the value of conducting such an analysis. Therefore, working closely with other government agencies as well as incorporating feedback from experts who commented on the rule, one of the main changes we made since the proposal was that we have quantified the uncertainty associated with specifically the international indirect land use change emissions associated with increased biofuel production. More discussion of treatment of uncertainty is found in Section 2.4.4.2.8.

## 2.3 Goals and Scope of This Analysis

Lifecycle analysis is used in several ways for this rulemaking. Fuel-specific GHG reductions are used to develop threshold determinations for specific fuels. Lifecycle analysis is also used to determine the overall impact of the rulemaking on GHG emissions worldwide. The first step was to establish the goals and scope for this analysis, as summarized below.

### 2.3.1 Goal

The RFS2 rulemaking involves determining lifecycle GHG impacts of specific fuels and fuel pathways for comparison with thresholds as defined in the legislation. Obligated parties will be required to use mandated quantities of renewable fuels, but only fuels that meet the GHG thresholds can qualify under the program. (Fuels produced at grandfathered facilities are exempt from these GHG threshold requirements.) The lifecycle GHG reductions represent the GHG differences between renewable fuels relative to the petroleum-based gasoline and diesel that they displace. The lifecycle methodology described here is used to determine the GHG displacement values for different renewable fuels to be compared to the thresholds. Therefore this analysis will provide:

- Amount of GHG emissions (on a mass basis) per amount of fuel produced (on an energy content basis) for both conventional petroleum based fuels and renewable fuels.
- Results are combined to quantify the emission change per energy unit (i.e., per BTU) of renewable fuel compared to that for the conventional fuel replaced.

### 2.3.2 Scope

#### 2.3.2.1 Scenario Analysis

To quantify the lifecycle GHG emissions associated with the increase in renewable fuel mandated by EISA, we needed to compare the impacts of renewable fuels with EISA to a reference case without EISA. Since it is not practical or workable to conduct such an analysis and come up with factors for every year, to carry out this analysis we chose to look at the final year of the RFS2 standards when they are fully phased in. For our reference case we assumed a “business as usual” volume of a particular renewable fuel based on what would likely be in the fuel pool in 2022 without EISA as predicted by the Energy Information Agency’s Annual Energy

Outlook (AEO) for 2007 (which took into account the economic and policy factors in existence in 2007 before EISA). For our control case we assumed the higher volumes of renewable fuels as mandated by EISA for 2022. For each individual biofuel, we analyzed the incremental impact of increasing the volume of that fuel to the total mix of biofuels needed to meet the EISA requirements while holding volumes of other fuels constant. Any changes between now and 2022 in factors such as crop yields, energy costs, or production plant efficiencies, both domestically and internationally, are reflected in both scenarios. Rather than focus on the impacts associated with a specific gallon of fuel and tracking inputs and outputs across different lifecycle stages, we determined the overall aggregate impacts across sections of the economy in response to a given volume change in the amount of biofuel produced. We then normalize those impacts to a gallon of fuel by dividing total impacts over the given volume change. In the case of overall rule impacts, we analyze the change in reference vs. control case volumes for all fuels together and take the absolute GHG results (e.g., do not normalize the overall rule impacts).

We did not calculate the emission impacts for each gallon of fuel based upon its unique production characteristics which could vary widely across the nation (e.g., a gallon of ethanol produced using corn grown in Iowa may have different direct lifecycle emissions impacts than a gallon of ethanol produced at an identical facility in Nebraska using corn grown in Nebraska due to regional differences in agricultural practices. However, on a lifecycle basis, considering the indirect impacts in the context of the entire corn market they are not different). Rather, we determined the overall aggregate impacts across sections of the economy in response to a given volume change in the amount of biofuel produced. In the case of agricultural impacts, we assessed the impact on the entire U.S. agricultural system that would result from expanded demand for biofuel feedstock. We then normalized those impacts to a gallon of fuel by dividing total impacts over the renewable fuel volume change between our business as usual case and the EISA volumes. Similarly, we estimated the typical emissions impact of a type of biofuel production facility (e.g., a plant that uses the dry mill process to turn corn starch into ethanol). The emissions assessment from a typical facility was then ascribed to all biofuel produced across facilities using that same basic technology.

We focus our final rule analyses on 2022 results for two main reasons. First, it would require an extremely complex assessment and administratively difficult implementation program to track how biofuel production might continuously change from month to month or year to year. Instead, it seems appropriate that each biofuel be assessed a level of GHG performance that is constant over the implementation of this rule, allowing fuel providers to anticipate how these GHG performance assessments should affect their production plans. Second, it is appropriate to focus on 2022, the final year of ramp up in the required volumes of renewable fuel as this year. Assessment in this year allows the complete fuel volumes specified in EISA to be incorporated. This also allows for the complete implementation of technology changes and updates that were made to improve or modeling efforts. For example, the inclusion of price induced yield increases and the efficiency gains of DDGS replacement are phased in over time. Furthermore, these changes are in part driven by the changes in earlier years of increased biofuel use.

Several of the lifecycle emission impacts for one fuel are interrelated with those of another fuel, in particular the land-use changes. For our analysis of the overall GHG impacts of the program (discussed in Section 2.7), we modeled all of the fuel changes simultaneously to determine the land-use impact. However, from that analysis it is not possible to differentiate the contribution of the land-use change to one fuel vs. another. As a result, for this analysis we had to model the impacts of just one fuel change at a time. In doing this we have held the other fuel volumes constant at their mandated levels in order to best approximate the impacts a single fuel change would have in the context of the full RFS2 standard volumes.

We used the same approach to determine the lifecycle GHG emissions for corn ethanol, cellulosic ethanol, biodiesel produced from soybean (and other vegetable) oils, and biodiesel produced using waste oils as feedstock. For waste oils, we note that no land use changes are included in the FASOM assessment, because any land use impacts are attributed to the original purpose of the feedstock (e.g.., the use of the vegetable oil for cooking or the production of animals for their meat), rather than the biofuel produced from the recovered waste material.

FASOM does not model feedstocks for fuels produced outside the U.S. We addressed imported ethanol by analyzing the difference in total GHG emissions based on two 2022 scenarios using only the results from FAPRI-CARD modeling runs: (1) the business as usual reference case volume of 0.6 Bgal and (2) an RFS2 projected volume of 2.2 Bgal of imported sugarcane ethanol.

Current models present some challenges in estimating GHG lifecycle emissions for cellulosic biofuels. For example, the FAPRI-CARD model used for this analysis did not include switchgrass or similar energy crops, and could only use corn stover or other food crop residues as feedstock in predicting cellulosic biofuel impacts. To overcome this limitation we ran the FASOM model with a switchgrass scenario to generate domestic land use and crop change results. We then applied these domestic crop changes by region to the FAPRI-CARD model to generate the international land use change and crop shifting due to the domestic impacts predicted by the FASOM switchgrass scenario.

For biofuels made from wastes and byproducts (e.g., MSW, rendered fats and waste oils and corn stover feedstock), we assumed no land use changes, because these biofuel feedstocks do not compete for domestic crop acreage. For corn stover, we analyzed only the change in domestic GHG emission resulting from an increase in fertilizer replacement application rates to compensate for the removal of stover from the land. Table 2.3-1 shows the different fuel scenarios considered.

**Table 2.3-1. Fuel Volume Scenarios Considered in This Analysis (Billions of Gallons)**

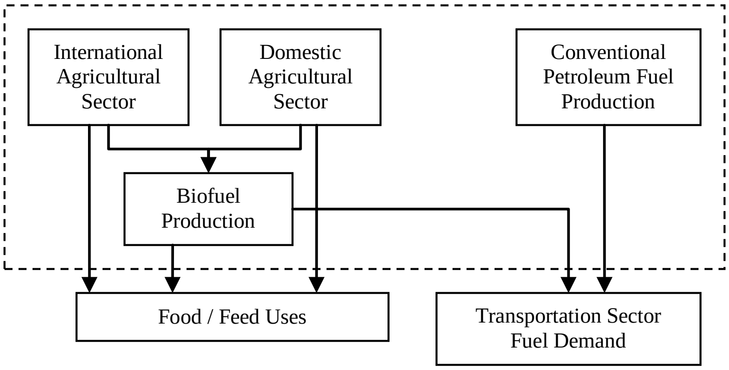
| **Biofuel** | **Reference Case – Low Volume** | **Control Case – High Volume** | **Change** |
|---|---|---|---|
| Corn Ethanol | 12.3 | 15.0 | 2.7 |
| Switchgrass Cellulosic Ethanol | 0 | 7.9 | 7.9 |
| Corn Residue Cellulosic Ethanol | 0 | 4.9 | 4.9 |
| Imported Sugarcane Ethanol | 0.6 | 2.2 | 1.6 |
| Soybean Oil Biodiesel | 0.1 | 0.6 | 0.5 |

### 2.3.2.2 System Boundaries

It is important to establish clear system boundaries in lifecycle analysis. By determining a common set of system boundaries, different fuel types can then be validly compared. As described in the previous section, we have assessed the direct and indirect GHG impacts in each stage of the full fuel lifecycle for biofuels and petroleum fuels.

Figure 2.3-1 provides a simplified diagram describing the system studied.

**Figure 2.3-1. Simplified Lifecycle System Diagram**



The different fuel volume scenarios were compared based on delivery of the same functions, in this case providing for both the agricultural sector market and transportation fuels markets. Within the overall system shown in Figure 2.3-1 the unit process listed in Table 2.3-2 will be considered.

**Table 2.3-2. Unit Processes Considered**

| Biofuel | Petroleum-Based Fuel |
|---|---|
| Feedstock Agriculture | Crude Oil Extraction |
| Feedstock Transport | Crude Oil Transport |
| Feedstock Processing & Biofuel Production | Refining |
| Biofuel Transport and Distribution | Fuel Transport and Distribution |
| Biofuel Tailpipe Emissions | Fuel Tailpipe Emissions |

Included in each unit process shown in Table 2.3-2 are the emissions and energy use associated with each operation as well as upstream components that feed into them. For example, the feedstock agriculture stage includes emissions from fuel used in tractors as well as from producing and transporting the fertilizer used in the field. Electricity production emissions are included in almost all of the stages shown. For direct impacts, as was the case in the proposal analysis, this results in system boundaries that include operation-related activities, but not infrastructure-related activities. As such, while we do include the emissions associated with the operation of farm equipment and trucks used for feedstock / fuel transportation we do not include the emissions associated with the production of the equipment or vehicles. Furthermore, we include the emissions from the operations of biofuel production plants and petroleum refineries but we do not include emissions from producing the material used to construct the facilities.

In determining what indirect impacts to include in the system boundaries of this analysis we focus on the goal and scope of the analysis as specified by the statutory language in EISA.

The Act specifies different categories of renewable fuels, conventional renewable fuel, advanced biofuel, cellulosic biofuel, and biomass-based diesel. The categories of fuel are defined in part based on their GHG emissions. For example for cellulosic biofuel:

> *The term 'cellulosic biofuel' means renewable fuel derived from any cellulose, hemicellulose, or lignin that is derived from renewable biomass and that has lifecycle greenhouse gas emissions, as determined by the Administrator, that are at least 60 percent less than the baseline lifecycle greenhouse gas emissions.*

So, the main goal of this analysis is to determine the lifecycle GHG emissions of different biofuel feedstock and fuel pathways for determination of compliance against the GHG thresholds as defined and mandated in the Act. More specifically the language stipulates that the analysis compares biofuel "lifecycle greenhouse gas emissions" against the "baseline lifecycle greenhouse gas emissions".

Biofuel lifecycle greenhouse gas emissions are further defined as:

> *The term 'lifecycle greenhouse gas emissions' means the aggregate quantity of greenhouse gas emissions (including direct emissions and significant indirect emissions such as significant emissions from land use changes), as determined by the Administrator, related to the full fuel lifecycle, including all stages of fuel and feedstock production and distribution, from feedstock generation or extraction through the distribution and delivery and use of the finished fuel to the ultimate consumer, where the mass values for all greenhouse gases are adjusted to account for their relative global warming potential.*[ssssss]

This definition forms the basis of defining the system boundaries for the biofuels lifecycle analysis. As the language specifically mandates that lifecycle GHG emissions include "direct emissions and significant indirect emissions such as significant emissions from land use changes" the system boundaries modeled include indirect impacts as determined through our economic modeling discussed in Section 2.4.

EISA defines baseline lifecycle greenhouse gas emissions as:

> *The term 'baseline lifecycle greenhouse gas emissions' means the average lifecycle greenhouse gas emissions, as determined by the Administrator, after notice and opportunity for comment, for gasoline or diesel (whichever is being replaced by the renewable fuel) sold or distributed as transportation fuel in 2005.*

---

[ssssss] Clean Air Act Section 211(o)(1).

Therefore, the petroleum production component of the system boundaries is specifically mandated by EISA to be based on the 2005 average for crude oil used to make gasoline or diesel sold or distributed as transportation fuel, and not the marginal crude oil that will be displaced by renewable fuel. Furthermore, as the EISA language specifies that the baseline emissions are to be only "average" lifecycle emissions for this single specified year and volume, it does not allow for a comparison of alternative scenarios. Indirect effects can only be determined using such an analysis; therefore, there are no indirect emissions to include in the baseline lifecycle greenhouse gas emissions. More discussion on the petroleum fuel baseline and potential impact of considering indirect impacts on the petroleum baseline are discussed in Section 2.5.

#### 2.3.2.3 Environmental Flows Considered

The lifecycle analysis discussed here evaluates the impacts of increased renewable fuel use on greenhouse gas emissions. EISA specifies a definition of greenhouse gases to include in the analysis:

> *The term 'greenhouse gas' means carbon dioxide, hydrofluorocarbons, methane, nitrous oxide, perfluorocarbons, sulfur hexafluoride. The Administrator may include any other anthropogenically emitted gas that is determined by the Administrator, after notice and comment, to contribute to global warming.*

EISA also specifies that the mass values for all greenhouse gases are adjusted to account for their relative global warming potential.

The relative global warming contribution of emissions of various greenhouse gases is dependant on their radiative forcing, atmospheric lifetime, and other considerations. For example, on a mass basis, the radiative forcing of $CH_4$ is much higher than that of $CO_2$, but its effective atmospheric residence time is much lower. The relative warming impacts of various greenhouse gases, taking into account factors such as atmospheric lifetime and direct warming effects, are reported on a '$CO_2$-equivalent' basis as global warming potentials (GWPs). The GWPs used in this analysis were developed by the UN Intergovernmental Panel on Climate Change (IPCC) as listed in their Second Assessment Report, and are shown in Table 2.3-3. Second assessment report values are used to be consistent with current standards for international reporting of GHG emissions.

**Table 2.3 3.**
**100 Year Global Warming Potentials for Greenhouse Gases**

| Greenhouse Gas | GWP |
|---|---|
| $CO_2$ | 1 |
| $CH_4$ | 21 |
| $N_2O$ | 310 |

Greenhouse gases are measured in terms of $CO_2$-equivalent emissions ($CO_2e$), which result from multiplying the GWP for each of the three pollutants shown in the above table by the mass of emissions for each pollutant. The sum of impacts for $CH_4$, $N_2O$, and $CO_2$, yields the total effective GHG impact. Other GHGs like HFCs, PFCs and SF6 are not released in significant amounts over the lifecycle of renewable or petroleum fuels, and are therefore not tracked in this analysis. Other non-GHG climate impacts like albedo (light reflectance), land surface roughness, hydrologic and energy flux, and loss of forest aerosols, while potentially an important aspect of climate impacts associated with land use change, are currently outside the scope of this analysis.

Other environmental flows besides GHG emissions are also considered in our analysis for this rulemaking. Criteria and toxic air pollutants are modeled and results are described in Chapter 3 of the RIA. Water use and impacts are also considered and are described in Chapter 6 of the RIA.

#### 2.3.2.4 Data Quality

Lifecycle analysis is a data intensive process and the results are affected by data quality. Data quality may be defined by specific characteristics that describe both quantitative and qualitative aspects of data, as well as the methods used to collect and integrate those data into the analysis. The quality of data used can be characterized by how well the geographic, technical and temporal aspects of the data match the goals and scope of the analysis in question.

The quality of the data used in this analysis was classified based on its geographic, technical and temporal relevance to the goals of the study as follows:

> **Geographic coverage –** this analysis was conducted without any regard to the geographic attributes of where emissions or energy use occurs. The benefits of this proposed rule represent global reductions in GHG emissions and energy use, not just those occurring in the U.S. For example, the savings associated with reducing overseas crude oil extraction and refining are included here, as are the international emissions associated with producing imported ethanol. Data for agricultural sector impacts include both U.S. and international defaults. Agricultural commodity production in other countries was based on data specific to those areas (e.g., fertilizer production in other countries). Land use change was specifically modeled in different countries; impacts of land use change were based on factors representing sub-country level land characteristics, and for areas where data was not available averages were used.
>
> **Technology coverage –** this analysis models industries that do not exist yet – cellulosic ethanol and renewable diesel for example. Therefore assumptions based on existing information and modeling were made to represent these industries rather than relying on existing facility data. Even for industries that currently exist there is expected to be a range of technology development over time. For this analysis we have made our best projections for what the industry may look like by 2022. There is expected to be considerable variation in the technologies used, for example combined heat and power and corn oil fractionation in a dry mill ethanol plant. To account for this we have looked at different fuel technology pathways as discussed in Section 2.4.7.
>
> **Temporal coverage –** this analysis considered impacts in 2022. Therefore we modeled future data; we projected ethanol production in 2022 based on process models –

consistent with cost analysis used in this rulemaking. For example, this assumed that future plants will be more energy efficient then current plants. Agricultural sector models also represented 2022 values including improvements in yields and cropping patterns.

#### 2.3.2.5 Addressing Uncertainty

The peer review, the public comments we have received, and the analysis conducted for the proposal and updated here for the final rule, indicate that it is important to take into account indirect emissions when looking at lifecycle emissions from biofuels. It is clear that, especially when considering commodity feedstocks, including the market interactions of biofuel demand on feedstock and agricultural markets is a more accurate representation of the impacts of an increase in biofuels production on GHG emissions than if these market interactions are not considered.

However, it is also clear that there are significant uncertainties associated with these estimates, particularly with regard to indirect land use change and the use of economic models to project future market interactions. Reviewers highlighted the uncertainty associated with our lifecycle GHG analysis and pointed to the inherent uncertainty of the economic modeling.

Therefore, working closely with other government agencies as well as incorporating feedback from experts who commented on the rule, we have quantified the uncertainty associated with specifically the international indirect land use change emissions associated with increased biofuel production. There are four main areas of uncertainty in our modeling approach:

- Economic Modeling Inputs
- Types of Land Converted and GHG Emission Factors
- Methodology Choices
- Other GHG Factors and Input Data

Although there is uncertainty in all portions of the lifecycle modeling, we focused our uncertainty analysis on the factors that are the most uncertain and have the biggest impact on the results. For example, the energy and GHG emissions used by a natural gas-fired ethanol plant to produce one gallon of ethanol can be calculated through direct observations, though this will vary somewhat between individual facilities. The indirect domestic emissions are also fairly well understood, however these results are sensitive to a number of key assumptions (e.g., current and future corn yields). The indirect, international emissions are the component of our analysis with the highest level of uncertainty and have particularly significant impact on our overall assessment results. For example, identifying what type of land is converted internationally and the emissions associated with this land conversion are critical issues that have a large impact on the GHG emissions estimates.

Therefore, we focused our efforts on the international indirect land use change emissions and worked to manage the uncertainty around those impacts in three ways: (1) getting the best information possible and updating our analysis to narrow the uncertainty, (2) performing sensitivity analysis around key factors to test the impact on the results, and (3) establishing reasonable ranges of uncertainty and using probability distributions within these ranges in threshold assessment. The following sections outline how we have incorporated these three approaches into our analysis.

Economic Modeling Inputs: The use of economic models and the uncertainty of those models to accurately predict future agricultural sector scenarios was one of the main comments we received on our analysis. While the comments and specifically the peer review supported our need to use economic models to incorporate and measure indirect impacts of biofuel production they also highlighted the uncertainty with that modeling approach, especially in projecting out to the future.

However, it is important to note that while many factors impact the certainty in predicting total land used for crop production, making accurate predictions of many of these factors are not relevant to our analysis. For example different assumptions about economic growth rates, weather, and exchange rates will all impact future agricultural projections including amount of land use for crops. However, we are interested only in the difference between two biofuel scenarios holding all other changes constant. So the absolute values and projections for crops, etc. in the model projections are not as important as the difference the model is projecting due to an increase in biofuels production. This limits the uncertainty of using the economic models for our analysis.

The main factors impacting the economic modeling and land use results due to biofuels are overall crop / commodity demand and yields (and the responsiveness of these parameters to price changes). To examine the impact of changes in yield on the overall biofuel lifecycle GHG results, we have made two main changes in the economic modeling used for the proposal. In order to update our analysis and reduce uncertainty we have included a price induced yield impact, as discussed in RIA Chapter 5. Furthermore we also include a sensitivity analysis of a high yield scenario to test the impact of higher yields on the results, as discussed in Section 2.6.2.

Types of Land Converted and Land Conversion GHG Emissions Factors: The international indirect land use change impacts of biofuels were determined based on the results of the economic models that provide the total amount of new land needed. The results of the economic models were combined with recent satellite data to predict the types of land converted to meet the increased land demand. GHG emissions factors were then applied to the type of land to calculate GHG emissions from land use change. As this is one of the areas of greatest uncertainty we specifically incorporated an approach to quantify the uncertainty in our satellite data and GHG emissions estimates and incorporated these results into our analysis.

Methodology Choices: A main underlying methodological decision that impacts the overall lifecycle GHG results is how to deal with the timing of emissions. This is manifested in two main ways, the first is how to deal with short term land use change emissions versus ongoing benefits of the use of biofuels, and the second is what timeframe to consider the analysis for. The main approach for addressing this uncertainty was to conduct sensitivity analysis with various methodology choices, as presented in Section 2.6.2.1. For example, we used a 30-year time period for our lifecycle analysis, but we also present results with different time periods, as well as the payback periods for each fuel, which is a metric that does not require the analyst to choose a specific time period.

Other GHG Factors and Input Data: Non-economic modeling inputs and assumptions impact overall GHG results, for example crop production inputs (energy use for tractors, etc.), and agricultural sector GHG emissions (livestock, soil $N_2O$, etc.). These factors are applied on top of economic modeling to determine mainly the non-land use GHG impacts of agriculture. While there is some uncertainty inherent in the factors, most of them do not have a significant impact on the overall results.

For the final rule analysis, instead of developing uncertainty profiles and ranges around these other input factors, we focused on reducing the uncertainty through updates to improve our data and modeling. For example, $N_2O$ emissions from soil as part of crop production is a key component of agricultural sector GHG emissions so we focused on updating our analysis to include the most up to date information on this source of emissions. We also had our analysis of international agricultural sector GHG emissions peer reviewed and have updated our analysis in response to the peer review comments.

## 2.4 Biofuels Analysis

### 2.4.1 Modeling Approach

As mentioned in Section 2.2, our methodology includes the use of agricultural sector economic models. Our methodology involves the use of the FASOM model to determine domestic agriculture sector-wide impacts of increased biofuel production, and the FAPRI-CARD model to determine international changes in crop production and total crop. Agricultural sector GHG emissions are estimated by FASOM, and FAPRI-CARD results were converted to GHG emissions based on GREET defaults and IPCC emission factors. Biofuel process energy use and associated GHG emissions were based on process models for the different pathways considered. Feedstock and co-product transportation GHG emissions were based on GREET defaults.

The agricultural sector models were used to determine the impacts associated with biofuels production by comparing two similar scenarios in both models. Both agricultural sector models were run with two similar volumes of the specific fuel in question, while other fuel volumes were held constant to isolate the fuel-specific impacts. Table 2.4-1 shows the 2022 fuel volumes modeled in FASOM in order to isolate the incremental impacts of each type of renewable fuel. Section 2.3 includes more discussion of the fuel volume scenarios.

Table 2.4 1.  2022 Fuel Volumes Modeled with FASOM (Billions of Gallons)

| | Control Case | Biodiesel Only Case | Corn Ethanol Only Case | Corn Stover Ethanol Only Case | Switchgrass Ethanol Only Case |
|---|---|---|---|---|---|
| Soybean Biodiesel | 0.6 | 0.1 | 0.6 | 0.6 | 0.6 |
| Corn Ethanol | 15.0 | 15.0 | 12. 3 | 15.0 | 15.0 |
| Corn Stover Ethanol | 4.9 | 4.9 | 4.9 | 0.0 | 4.9 |
| Switchgrass Ethanol | 7.9 | 7.9 | 7.9 | 7.9 | 0.0 |

The total impacts from changes in biofuel production were calculated by taking the difference in total GHG emissions from the two scenarios considered.  Per gallon or per million British Thermal Units (mmBTU) impacts were calculated by dividing the total GHG emission changes by the increase in volume of fuel represented in the scenarios.  Therefore, the results presented in this proposed rulemaking represent the per mmBTU “average marginal” impact of the change in fuel volumes considered.  In other words, the GHG impacts were estimated for a marginal increase in fuel production, and the average impact of a marginal gallon was calculated.

### 2.4.2 Domestic Agriculture

GHG emissions from the domestic agricultural sector were estimated with the FASOM model, a partial equilibrium economic model of the U.S. forest and agricultural sectors.  As discussed in Section 2.2, FASOM accounts for changes in GHG emissions from most agricultural activities, including the total amount of fertilizer, chemicals, gasoline, diesel and electricity used on farms for the entire domestic agricultural sector. It also captures changes in the soil management, livestock production and U.S. agricultural exports.  More detail on the FASOM model can be found in Chapter 5 of the RIA.  For all figures and tables in Section 2.4.2, we report results for the biochemical pathway under the “Corn Stover Ethanol” and “Switchgrass Ethanol” scenarios.

Figure 2.4-1 shows the total harvested crop acres in the different fuel-specific pathway scenarios.  The projected changes in total harvested acres are modest, because we modeled the incremental difference in renewable fuel volumes between the scenarios.

Figure 2.4 1.  FASOM Projected Domestic Harvested Acres, 2022

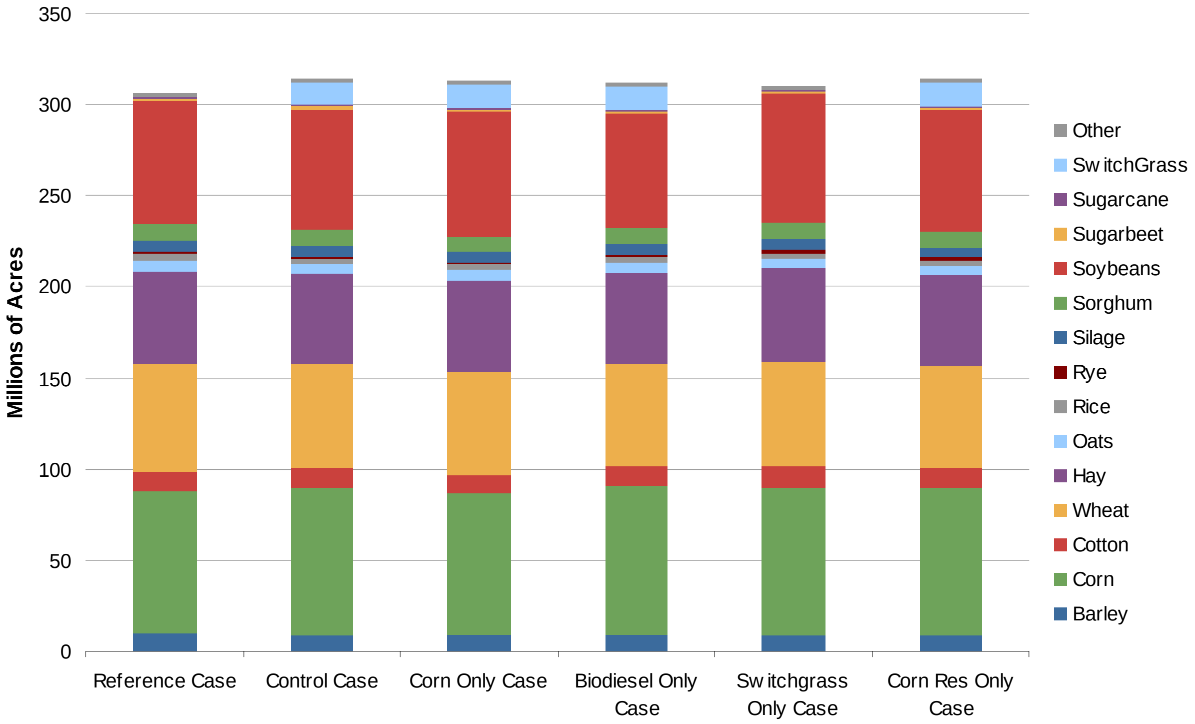
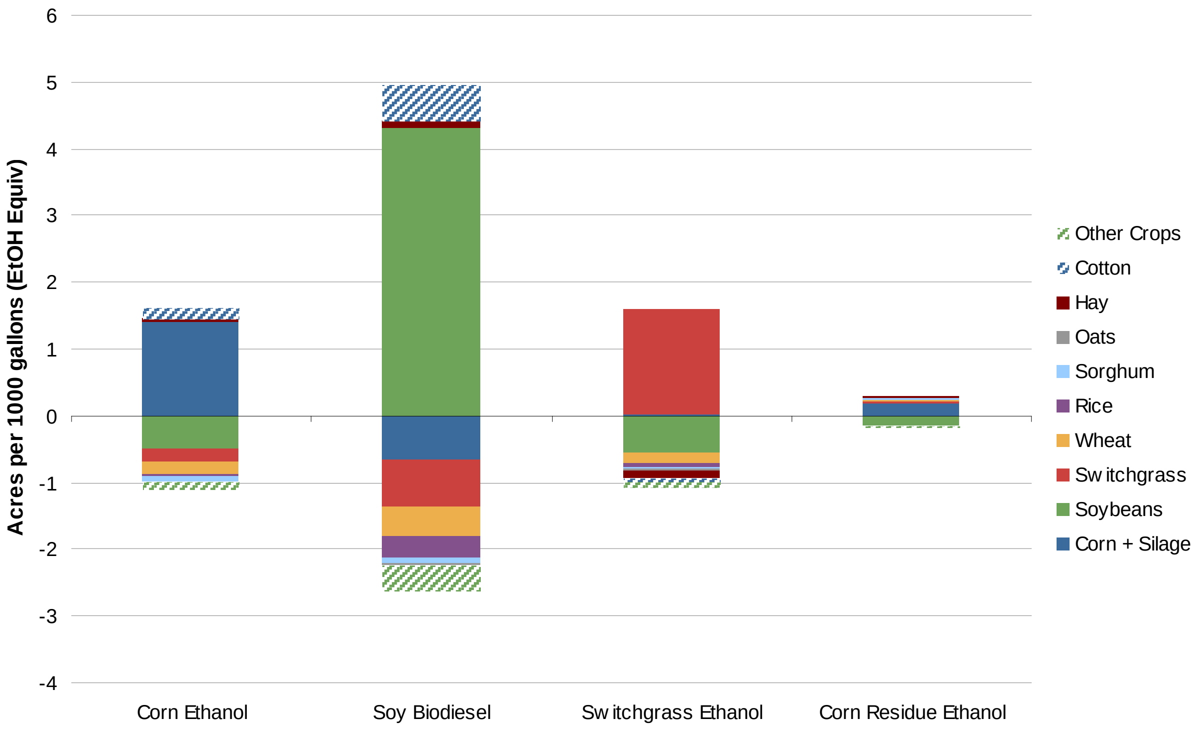


Figure 2.4-2 includes the projected changes in harvested crop acres by field crop for the fuel volume cases considered (acreage changes are normalized per thousand gallons of renewable fuel production).  In the corn ethanol scenario, corn acreage increased; area planted with soybeans, wheat, switchgrass, sorghum and rice decreased; and harvested acres of other crops were practically unchanged.  As anticipated, soybean acreage decreased the most when corn ethanol production increased, because corn and soybeans are often in direct competition for fertile land.

**Figure 2.4 2.**
**Normalized Changes in Domestic Cropland by Crop, 2022**
**(acres per thousand gallons of renewable fuel)**



Soy-based biodiesel production induced a large increase in harvested soybean acres, largely due to the low yield of soy-based biodiesel in terms of gallons produced per acre. Cotton was the only other crop that increased substantially along with biodiesel production. The competition between corn and soybeans was evident again, as corn acreage saw a steep decline. However, switchgrass acres declined by nearly the same amount as corn, showing the relative competition between switchgrass and soybeans. Wheat, rice, barley, sorghum and rye also declined when biodiesel volumes increased.

In the scenario where switchgrass ethanol production increased, switchgrass was the only field crop to gain acreage, with the exception of a small increase in corn and sugarbeet acres. New switchgrass plantings displaced a wide variety of other crops (Figure 2.4-2). As discussed more in RIA Chapter 5, the FASOM runs for the proposed rule project that switchgrass will primarily be grown in Kansas, Missouri, Texas, Oklahoma, and Arkansas

Production of ethanol from corn residue had a very small effect on the acreage of other crops. This was expected because corn stover production does not displace other crop production, as corn stover is a residual product of corn cultivation. FASOM did project minor amounts of crop shifting in the corn stover scenario, because using corn stover for ethanol can increase the profitability of corn production in certain regions, with subsequent impacts. The effects of corn stover harvesting on agricultural inputs, such as the need to use more fertilizer after stover removal, are discussed below.

#### 2.4.2.1 Domestic Crop Inputs

FASOM utilizes data about crop inputs to build crop budgets for field crops across 11 market regions and 63 sub-regions. FASOM crop budgets include data on yields, fertilizer, chemicals, and energy use needed to grow crops in each of the different regions. The crop budgets are based on USDA historic data and are also projected into the future. The crop budgets represent an average for each region, and do not specifically calculate input or yield changes that could result from the use of marginal croplands or altered crop rotation patterns (e.g., continuous corn production).[TTTTTT] Table 2.4-2 defines the 11 market regions in FASOM. RIA Chapter 5 includes a detailed discussion of the FASOM crop budgets, including assumptions about crop yields and yield growth rates. Below we provide a summary of some of the key FASOM assumptions that were used to estimate domestic agricultural GHG emissions.

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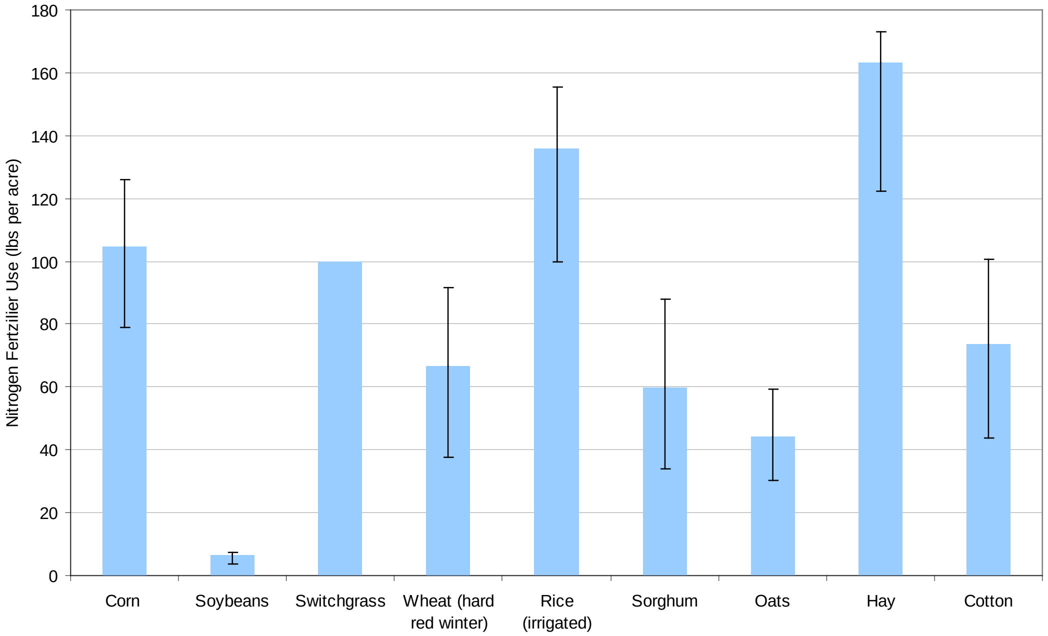
[TTTTTT] FASOM does not explicitly model the selection of alternative crop rotations. Because the model operates in 5-year time steps, it has not generally been applied to shorter-term decisions such as changes in rotation patterns. Rather, the model data implicitly reflect average conditions for crop production (e.g., yields, input use, etc.) associated with historical rotation patterns on a regional level.

**Table 2.4-2. Definitions of 11 Market Regions in FASOM**

| Key | Market Region | Production Region (States/Subregions) |
|---|---|---|
| NE | Northeast | Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, Vermont, West Virginia |
| LS | Lake States | Michigan, Minnesota, Wisconsin |
| CB | Corn Belt | All regions in Illinois, Indiana, Iowa, Missouri, Ohio (IllinoisN, IllinoisS, IndianaN, IndianaS, IowaW, IowaCent, IowaNE, IowaS, OhioNW, OhioS, OhioNE) |
| GP | Great Plains | Kansas, Nebraska, North Dakota, South Dakota |
| SE | Southeast | Virginia, North Carolina, South Carolina, Georgia, Florida |
| SC | South Central | Alabama, Arkansas, Kentucky, Louisiana, Mississippi, Tennessee, Eastern Texas |
| SW | Southwest (agriculture only) | Oklahoma, All of Texas but the Eastern Part (Texas High Plains, Texas Rolling Plains, Texas Central Blacklands, Texas Edwards Plateau, Texas Coastal Bend, Texas South, Texas Trans Pecos) |
| RM | Rocky Mountains | Arizona, Colorado, Idaho, Montana, Nevada, New Mexico, Utah, Wyoming |
| PSW | Pacific Southwest | All regions in California (CaliforniaN, CaliforniaS) |
| PNWE | Pacific Northwest—East side (agriculture only) | Oregon and Washington, east of the Cascade mountain range |
| PNWW | Pacific Northwest—West side (forestry only) | Oregon and Washington, west of the Cascade mountain range |

The crop budgets included in the FASOM model include data on input use that varies by crop, management practices, and region. There is often considerable regional variation in the inputs used per acre, which suggests that total input use (and the associated GHG emissions and other environmental impacts) will be affected as biofuel production causes crop shifting and alters crop management practices. For example, nitrogen fertilizer use is an important factor for lifecycle GHG analysis because of GHG emissions from fertilizer production and use. Figure 2.4-3 includes FASOM assumptions about average nitrogen fertilizer use by crop in 2022 for non-irrigated production without residue harvesting. Regions that have a zero nitrogen fertilizer use rate are not included in the averages. Figure 2.4-3 illustrates the relative fertilizer intensity of major crops. Corn, hay and silage are relatively fertilizer-intense crops; whereas soybeans require less than 10 pounds of nitrogen per acre (soybeans naturally fix nitrogen in the soil as they grow).

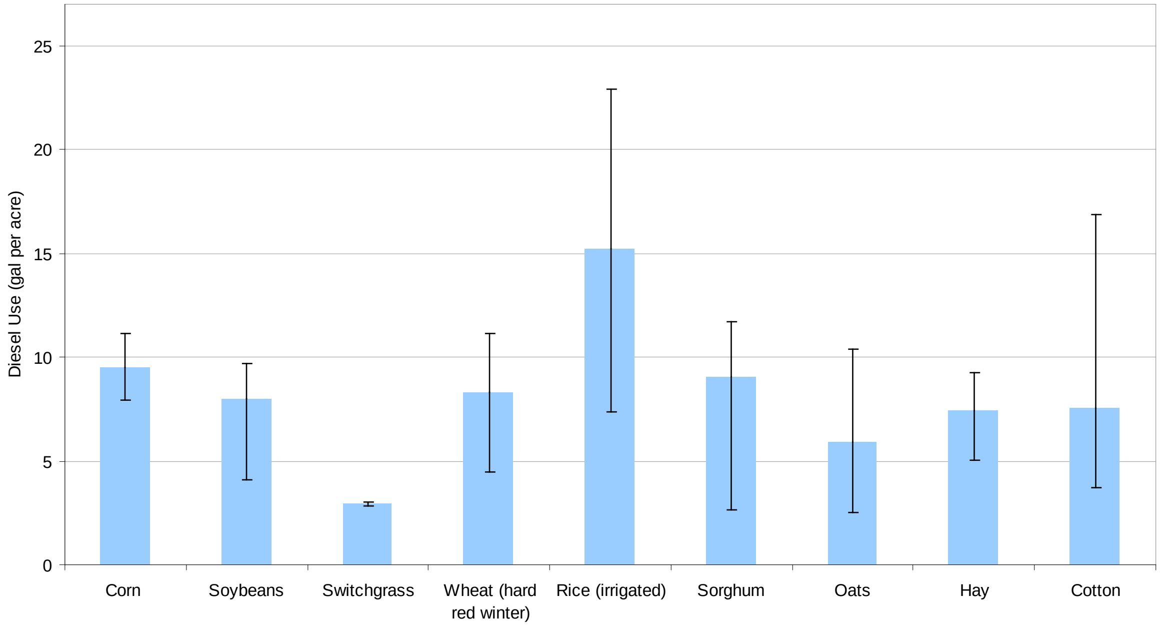
## Figure 2.4-3.
## FASOM Average Nitrogen Fertilizer Use by Crop, 2022
## Non-Irrigated, No Residue Harvesting
## (lbs per acre)



Note: The range indicates the regions with the highest and lowest average nitrogen fertilizer use rates.

Mechanized agriculture requires many forms of energy including diesel, gasoline, natural gas and electricity. The FASOM crop budgets include detailed energy use information by crop and region. Figure 2.4-4 includes FASOM assumptions for average diesel use by crop in 2022, for non-irrigated production without residue harvesting.

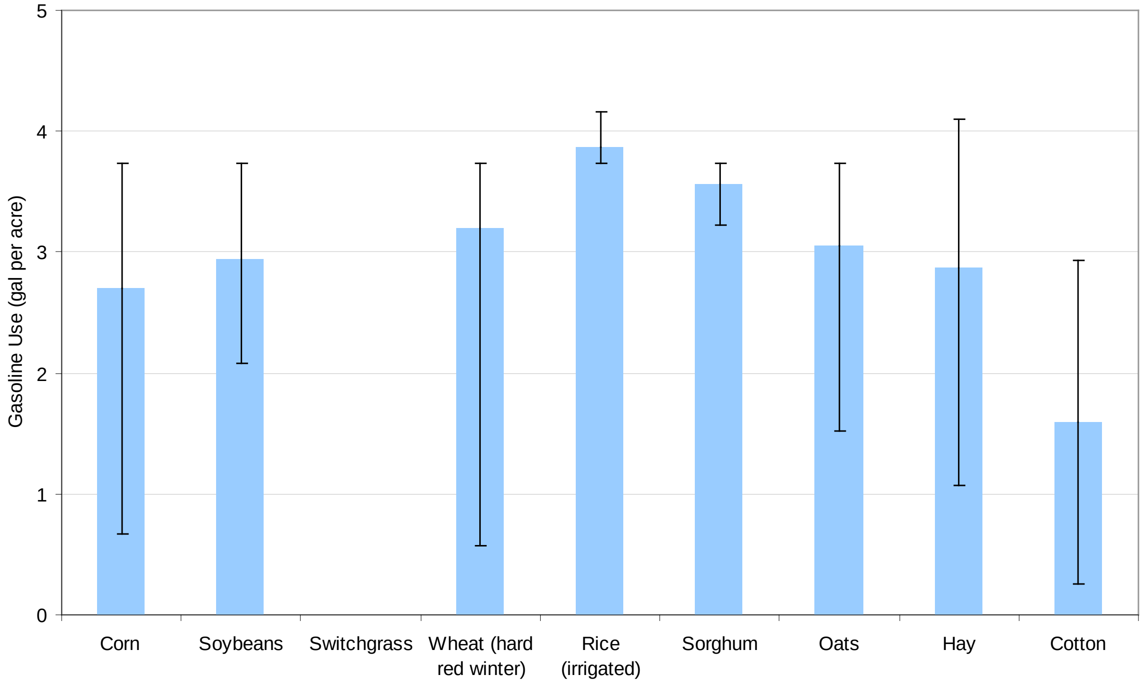
## Figure 2.4-4.
## FASOM Average Diesel Use by Crop, 2022
## Non-Irrigated, No Residue Harvesting
## (gallons per acre)



Note: The range indicates the regions with the highest and lowest average diesel use rates.

Figure 2.4-5 shows FASOM assumptions for average gasoline use by crop in 2022, for non-irrigated production without residue harvesting. The FASOM crop budgets do not include gasoline use for switchgrass production.

## Figure 2.4-5
## FASOM Average Gasoline Use by Crop, 2022
## Non-Irrigated, No Residue Harvesting
## (gallons per acre)



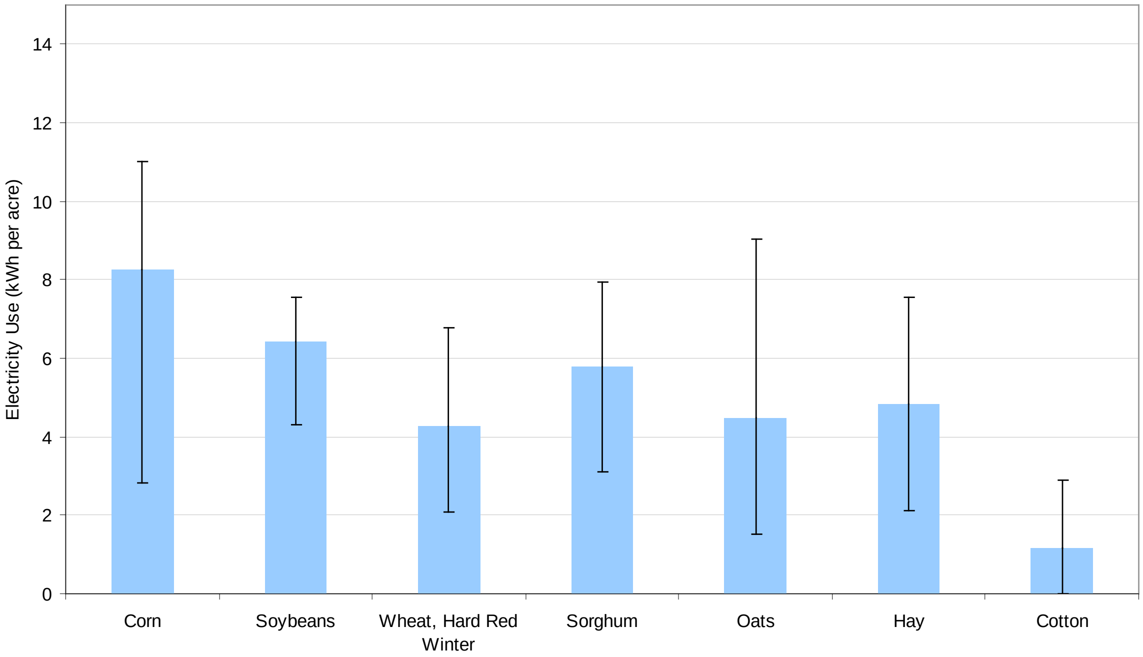
Note: The range indicates the regions with the highest and lowest average gasoline use rates.

FASOM crop budgets include electricity and natural gas use for irrigation water pumping. Rice and sugarbeets are the only crops assumed to use natural gas for water pumping (see Table 2.4-3). Therefore, overall natural gas use in each scenario is dependent on changes in these crops. For the rest of the irrigated crops that have private energy use for water pumping, electricity is the assumed energy source, with the largest electricity consumption in the Great Plains region (see Figure 2.4-6).

## Table 2.4-3.
## Natural Gas Usage for Irrigated Crop by Region, 2022
## (1000 cu ft/acre)

| Crop | CB | GP | LS | NE | PNWE | PSW | RM | SC | SE | SW |
|---|---|---|---|---|---|---|---|---|---|---|
| Rice | 23.3 | NA | NA | NA | NA | 0.0 | NA | 20.1 | NA | 0.0 |
| Sugarbeet | 26.1 | 9.7 | 26.1 | NA | 3.8 | 0.0 | 0.0 | NA | NA | 0.0 |

### Figure 2.4-6.
### FASOM Electricity Use by Crop, 2022
### Irrigated, No Residue Harvesting
### (kWh per acre)



Note: The range indicates the regions with the highest and lowest average gasoline use rates

Energy use for grain drying is calculated in FASOM based on assumptions that removing 10 percentage points of moisture from 100 bushels of grain requires 17.5 gallons of propane and 9 kWh of electricity. Thus, energy use per acre is calculated as the number of percentage points of moisture to be removed multiplied by the yield per acre and the energy use per percentage point and yield unit for each crop that is dried. Emissions are then calculated based on assumed emissions factors per unit of energy use by energy type. Table 2.4-4 shows the average emissions associated with grain drying that are used in FASOM. Drying rice is a relatively energy intensive process, as reflected in the grain drying GHG emissions per acre. Emissions from grain drying are included in the overall domestic agricultural GHG emissions estimates.

## Table 2.4-4. FASOM Average Carbon Dioxide Emissions from Grain Drying by Region (kgCO2e / acre)

| Crop | CB | GP | LS | NE | PNWE | PSW | RM | SC | SE | SW |
|---|---|---|---|---|---|---|---|---|---|---|
| Dryland | | | | | | | | | | |
| Corn | 161.4 | 135.9 | 202.2 | 160.5 | NA | NA | 66.1 | 24.5 | 43.8 | 15.2 |
| Sorghum | 99.4 | 22.3 | NA | 54.3 | NA | 17.7 | NA | NA | NA | NA |
| Soybeans | 26.0 | 7.0 | 24.1 | 14.3 | NA | NA | NA | NA | NA | NA |
| Wheat, Durham | NA | 5.1 | 23.4 | NA | NA | NA | NA | NA | NA | NA |
| Wheat, Hard Red Spring | NA | 6.7 | 25.4 | NA | 9.1 | NA | NA | NA | NA | NA |
| Wheat, Hard Red Winter | 51.3 | 11.1 | 51.6 | 34.5 | NA | 11.6 | NA | NA | NA | NA |
| Wheat, Soft White | NA | NA | NA | NA | NA | NA | 11.6 | NA | NA | NA |
| Irrigated | | | | | | | | | | |
| Corn | NA | 185.1 | NA | NA | 132.6 | 121.6 | 103.2 | 21.0 | NA | 30.7 |
| Rice | 1,216.6 | NA | NA | NA | NA | 1,667.3 | NA | 1,254.8 | NA | 1,400.8 |
| Sorghum | NA | 33.0 | NA | NA | NA | NA | NA | NA | NA | NA |
| Soybeans | NA | 10.3 | NA | NA | NA | NA | NA | NA | NA | NA |
| Wheat, Durham | NA | 11.3 | NA | NA | NA | 21.0 | NA | NA | NA | NA |
| Wheat, Hard Red Spring | NA | 10.2 | NA | NA | NA | NA | 17.6 | NA | NA | NA |
| Wheat, Hard Red Winter | NA | 15.4 | NA | NA | NA | 22.6 | NA | NA | NA | NA |
| Wheat, Soft White | NA | NA | NA | NA | NA | NA | 18.3 | NA | NA | NA |

Based on input data for each individual crop and the associated costs of production and projected prices, the model predicts how the total U.S. agricultural sector will change with increased feedstocks used for biofuel production. The results for total agricultural sector inputs of the different fuel scenarios considered are shown in Table 2.4-5 through Table 2.4-8.

## Table 2.4-5. Change in Domestic Agricultural Inputs under Corn Ethanol Scenario, 2022

| | Units per mmBTU | Corn Ethanol Only Scenario | Control Scenario | Difference | Percent Change |
|---|---|---|---|---|---|
| Total N use | Pounds | 136.6 | 138.8 | 2.1 | 1.5% |
| Total P2O5 use | Pounds | 31.2 | 31.7 | 0.5 | 1.5% |
| Total K2O use | Pounds | 38.8 | 39.5 | 0.7 | 1.9% |
| Total Lime Use | Pounds | 104.2 | 104.7 | 0.5 | 0.5% |
| Herbicide Use | Pounds | 1.9 | 2.0 | 0.0 | 2.2% |
| Pesticide Use | Pounds | 0.4 | 0.4 | 0.0 | 2.8% |
| Total Diesel Fuel use | Gal | 14.3 | 14.2 | -0.1 | -0.5% |
| Total Gasoline use | Gal | 1.7 | 1.7 | 0.0 | -0.9% |
| Total Electricity Use | kWh | 1.0 | 1.0 | 0.0 | 0.3% |
| Total Natural Gas Use | BTU | 248,002 | 234,746 | -13,257 | -5.6% |

### Table 2.4-6. Change in Domestic Agricultural Inputs in the Soy Biodiesel Scenario, 2022

| | Units Per mmBTU | Soy Biodiesel Only Scenario | Control Scenario | Difference | Percent Change |
|---|---|---|---|---|---|
| Total N use | Pounds | 437.1 | 435.3 | -1.8 | -0.4% |
| Total P2O5 use | Pounds | 99.2 | 99.4 | 0.2 | 0.2% |
| Total K2O use | Pounds | 123.3 | 124.0 | 0.7 | 0.6% |
| Total Lime Use | Pounds | 325.6 | 328.5 | 2.9 | 0.9% |
| Herbicide Use | Pounds | 6.2 | 6.2 | 0.0 | 0.3% |
| Pesticide Use | Pounds | 1.4 | 1.4 | 0.0 | 1.5% |
| Total Diesel Fuel use | Gal | 45.0 | 44.7 | -0.4 | -0.9% |
| Total Gasoline use | Gal | 5.3 | 5.4 | 0.1 | 1.6% |
| Total Electricity Use | kWh | 3.2 | 3.2 | 0.0 | 1.4% |
| Total Natural Gas Use | BTU | 833,308 | 736,362 | -96,946 | -13.2% |

### Table 2.4-7.
### Change in Domestic Agricultural Inputs in the Corn Stover Ethanol Scenario, 2022

| | Units per mmBTU | Corn Stover Only Ethanol Scenario | Control Scenario | Difference | Percent Change |
|---|---|---|---|---|---|
| Total N use | Pounds | 74.6 | 75.8 | 1.2 | 1.5% |
| Total P2O5 use | Pounds | 16.8 | 17.3 | 0.5 | 3.1% |
| Total K2O use | Pounds | 19.3 | 21.6 | 2.3 | 10.8% |
| Total Lime Use | Pounds | 57.3 | 57.2 | -0.1 | -0.2% |
| Herbicide Use | Pounds | 1.1 | 1.1 | 0.0 | 0.6% |
| Pesticide Use | Pounds | 0.2 | 0.2 | 0.0 | 0.4% |
| Total Diesel Fuel use | Gal | 7.8 | 7.8 | -0.1 | -0.8% |
| Total Gasoline use | Gal | 0.9 | 0.9 | 0.0 | 0.0% |
| Total Electricity Use | kWh | 0.6 | 0.6 | 0.0 | 0.0% |
| Total Natural Gas Use | BTU | 133,037 | 128,201 | -4,836 | -3.8% |

### Table 2.4-8.
### Change in Domestic Agricultural Inputs in the Switchgrass Ethanol Scenario, 2022

| | Units per mmBTU | Switchgrass Ethanol Only Scenario | Control Scenario | Difference | Percent Change |
|---|---|---|---|---|---|
| Total N use | Pounds | 44.5 | 45.9 | 1.4 | 3.1% |
| Total P2O5 use | Pounds | 9.8 | 10.5 | 0.7 | 6.2% |
| Total K2O use | Pounds | 12.5 | 13.1 | 0.6 | 4.3% |
| Total Lime Use | Pounds | 34.7 | 34.7 | 0.0 | -0.1% |
| Herbicide Use | Pounds | 0.7 | 0.7 | 0.0 | -1.1% |
| Pesticide Use | Pounds | 0.1 | 0.1 | 0.0 | -3.0% |
| Total Diesel Fuel use | Gal | 4.8 | 4.7 | -0.1 | -1.1% |
| Total Gasoline use | Gal | 0.6 | 0.6 | 0.0 | -4.2% |
| Total Electricity Use | kWh | 0.3 | 0.3 | 0.0 | -0.2% |
| Total Natural Gas Use | BTU | 90,890 | 77,690 | -13,200 | -17.0% |

The amounts shown in Table 2.4-5 through Table 2.4-8 were combined with GREET defaults for GHG emissions from production of fertilizer and chemicals to calculate GHG emissions changes. Fuel use emissions included both the upstream emissions associated with production of the fuel as well as combustion emissions, also from GREET. Emissions from electricity production represented average U.S. grid electricity production.

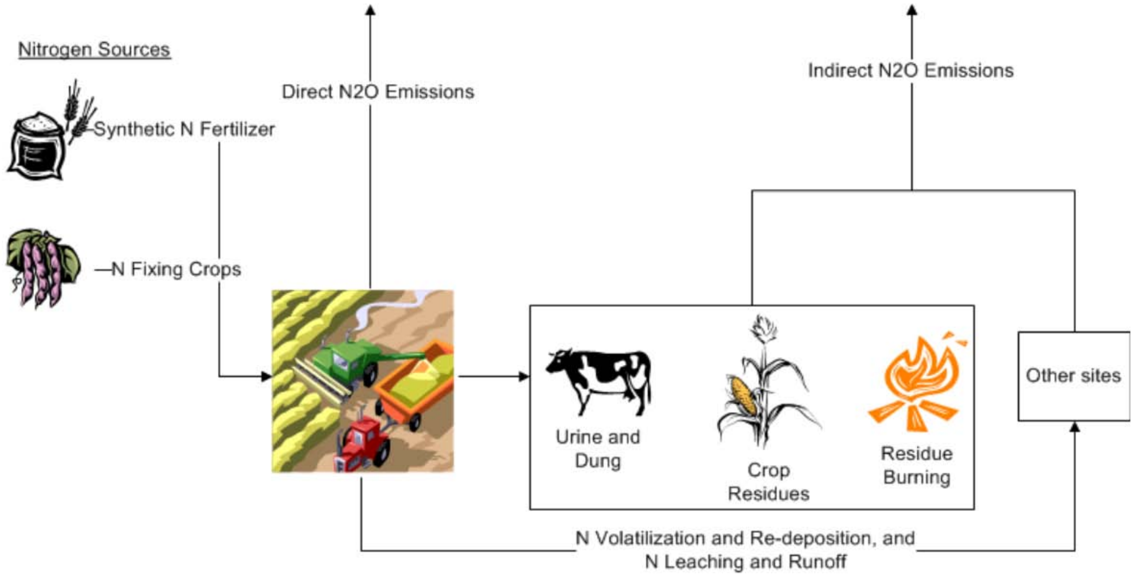
In addition to the GHG emissions associated with fertilizer and chemical production, and fuel production and use, there are several other non-fossil fuel combustion related GHG sources of emissions from the agricultural sector that would be impacted by the increased use of corn for ethanol and associated changes to the agricultural sector. FASOM provides directly the GHG emissions from these additional sources.

### 2.4.2.2 Domestic Nitrous Oxide Emissions

An important GHG impact from the agricultural sector is releases of nitrous oxide (N2O) emissions. N2O can be released from a number of different N-input sources including inorganic fertilizer, nitrogen fixing crops (e.g., soybeans), crop residues, and manure management. N2O can be released either directly or indirectly through N leaching offsite.

Figure 2.4-7 highlights some of the major sources of agricultural N2O emissions.

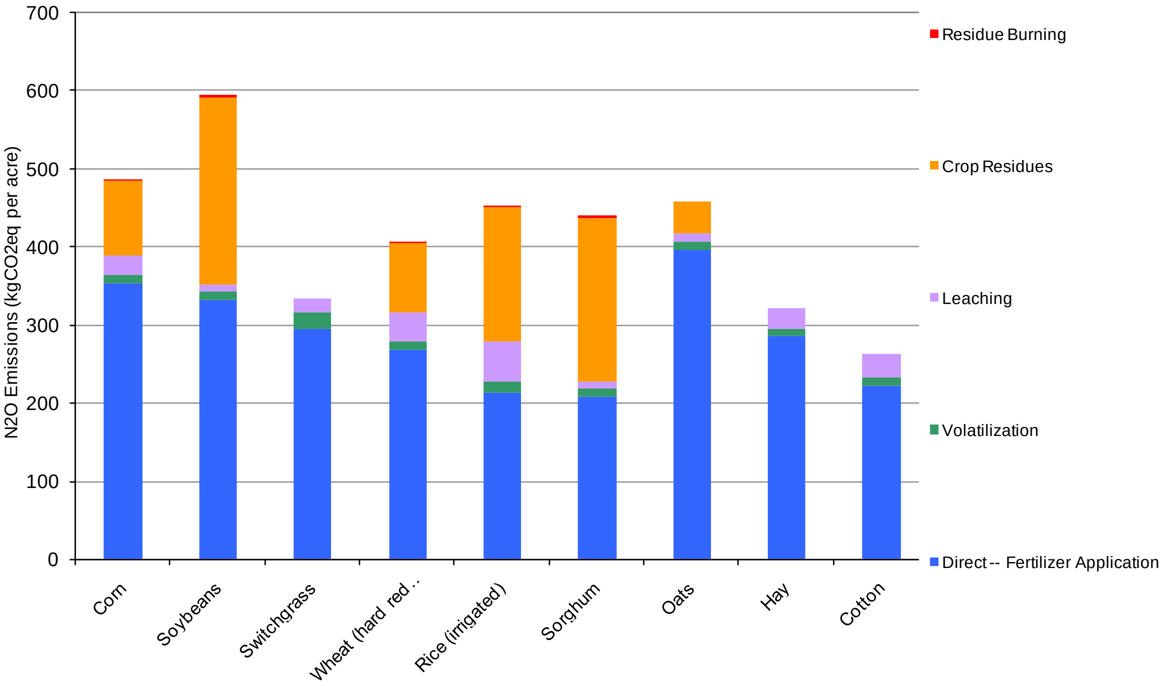
**Figure 2.4-7. Agricultural Sources of N2O Emissions**



Crutzen et al. show that, as long as it includes both direct and indirect emissions, top-down accounting for N2O emissions are not inconsistent with the IPCC bottom–up approach to N2O accounting.[515] Since the publication of the NPRM, the N2O emission factors in FASOM have been updated with the DAYCENT/CENTURY model by Colorado State University (CSU) to more accurately estimate direct and indirect N2O emissions in cropland. The FASOM modeling captures both direct N2O emissions from fertilizer application and N-fixing crops and indirect emissions from leaching, volatilization well as from crop residue emissions and residue burning, capturing all sources of N2O emissions and reflecting the most recent available science. This section discusses the changes made using the CSU DAYCENT/CENTURY work. It details the direct and indirect emissions from synthetic fertilizer, N fixing crops, and crop residue.

Figure 2.4-8 summarizes FASOM average direct and indirect N2O emissions per acre by crop. Livestock N2O emissions and N2O emissions associated with international agriculture are discussed in more detail in Section 2.4.2.3 and 2.4.3, respectively.

**Figure 2.4-8.**
**FASOM Average N2O Emissions by Crop (Non-Irrigated, No Residue Harvesting) (kgCO2e per acre)**



EPA worked with CSU to use the DAYCENT/CENTURY model to refine FASOM accounting of direct N2O emissions from fertilizer application and indirect emissions associated with nitrogen leaching, volitization, and surface runoff. Specifically, DAYCENT simulations account for all N inputs to agricultural soils, including mineral N fertilizer, organic amendments, symbiotic N fixation, asymbiotic N fixation, crop residue N, and mineralization of soil organic matter.

CSU used the DAYCENT/CENTURY model to simulate a suite of domestic U.S. land use and crop management in the 11 FASOM market regions (Table 2.4-2). The DAYCENT/CENTURY simulations provided regression equations with coefficients for N2O estimation that vary by region, crop type, irrigation status, and crop residue treatment. Each of the 63 FASOM regions was assigned the coefficients for its respective super-region. The regression equations were incorporated into FASOM to calculate N2O emissions per acre according to region, crop, irrigation status, and crop residue treatment.

FASOM estimates N2O emissions from crop residues and residue burning using IPCC guidelines, taking into account variation across regions in

- N content by crop based on yield,
- residue-to-crop ratio,
- percent dry matter,
- percentage of rice area burned in each state,
- burn and combustion efficiency,
- percent of residue burned by crop.

For crop residue emissions, FASOM assumes that 1% of N residing in crop residues that remain on the field is emitted as N2O emissions, following IPCC guidelines.

Field burning of crop residues is not considered a net source of CO2, because the carbon released to the atmosphere as CO2 during burning is assumed to be reabsorbed during the next growing season. Field burning of crop residues, however, does emit N2O and CH4, which are released during combustion. Field burning is not a common method of agricultural residue disposal in the United States. The primary crop types whose residues are typically burned in the United States are wheat, rice, sugarcane, corn, barley, soybeans, and peanuts.

FASOM assumes that a certain fraction of fields are burned each year, which results in N2O emissions as well as CH4 emissions. Using the IPCC default value for burned residue, FASOM assumes that, on average, 0.7% of N contained in the burned residue is emitted as N2O. FASOM predicts minor reductions in GHG emissions from residue burning under the full RFS2 policy due to reductions in crop production with residues that are typically burned. In addition, CH4 emissions are calculated based on the average methane emissions per acre; however, CH4 emissions are typically quite small relative to the other emissions tracked in FASOM.

### 2.4.2.3 Domestic Rice Production Emissions

Methane (CH4) emissions associated with rice production are also a source of non-combustion GHG emissions from the domestic agricultural sector. When rice fields are flooded, aerobic decomposition of organic material gradually depletes most of the oxygen present in the soil, causing anaerobic soil conditions. Once the environment becomes anaerobic, CH4 is produced through anaerobic decomposition of soil organic matter by methanogenic bacteria. Some of this CH4 is transported from the soil to the atmosphere through the rice plants via diffusive transport. Minor amounts of CH4 also escape from the soil via diffusion and bubbling through floodwaters.

FASOM assumes that all rice produced in the United States is grown in flooded fields and emits CH4. Although there are potentially changes in water and soil management practices that could be implemented to reduce methane emissions, FASOM assumes that reduction of rice acreage is the only available method for reducing CH4 emissions from rice cultivation. Thus, changes in CH4 emissions from rice cultivation result only from changes in the acreage planted to rice in the model.

Methane emissions per acre are calculated based on regional emissions factors per acre calculated for each region based on 2001 data from the EPA GHG inventory for 1990–2003 (see Table 2.4-9).[516] The model then calculates emissions from rice production based on emissions factors for each region and the distribution of rice acreage in the model solution.

**Table 2.4-9. FASOM Average Methane Emissions from Irrigated Rice Cultivation by Region (kg CO2e / acre)**

| Crop | CB | GP | LS | NE | PNWE | PSW | RM | SC | SE | SW |
|---|---|---|---|---|---|---|---|---|---|---|
| Rice | 1,826.1 | NA | NA | NA | NA | 1,783.4 | NA | 2,249.2 | NA | 4,375.0 |

Note: NA indicates not applicable, i.e., those crops were not cultivated under that irrigation status in that FASOM region. In addition, there is no dryland rice or sugarcane production or irrigated hybrid poplar, switchgrass, or willow production in FASOM.

As with other sources of emissions different management methods and other factors (such as soil type and amounts of fertilization) will impact CH4 emissions from rice production. With the exception of corn stover ethanol, FASOM projects that rice methane emissions will decrease for all fuel pathways analyzed due to decreased domestic rice acreage (Table 2.4-10).

**Table 2.4-10.**
**Change in Domestic Rice Emissions by Scenario, 2022**

| | Corn Ethanol | Soybean Biodiesel | Corn Stover Ethanol | Switchgrass Ethanol |
|---|---|---|---|---|
| Rice Methane Emissions (‘000 tons CO2e) | -42 | -506 | 159 | -938 |

### 2.4.2.4 Domestic Livestock Emissions

Livestock production and management also contribute significant non-combustion GHG emissions from the agricultural sector. GHG emissions from livestock come from two main sources: enteric fermentation and manure management. Enteric fermentation produces CH4 emissions as a by-product of normal digestive processes in animals. During digestion, microbes resident in an animal’s digestive system ferment food consumed by the animal. The amount of CH4 produced and excreted by an individual animal depends primarily upon the animal’s digestive system, and the amount and type of feed it consumes. Ruminant animals (e.g., cattle, buffalo, sheep, goats, and camels) are the major emitters of CH4 because of their unique digestive system.

FASOM projects changes in CH4 emissions associated livestock enteric fermentation due to change in livestock herd number. Changes in production of crops used for feeds, such as corn or soybeans, can impact feed prices which, in turn, drive livestock production and demand. Enteric fermentation emissions from livestock are calculated based on the number of each livestock type and on the average emissions per head. Average emissions per head are based on

2001 emissions values by livestock type and the number of livestock in each livestock category reported in the EPA GHG inventory report for 1990–2003.[517] There are emissions mitigation options included within the FASOM model, but these options do not enter the market in the absence of incentives for reducing CH4 emissions. Thus, enteric fermentation emissions are affected only by the number of animals in each livestock category in this model. The FASOM model generally predicts reductions in livestock herds as shown in Table 2.4-11.

**Table 2.4-11. Change in Domestic Livestock Herd Size by Scenario, 2022**

| **Livestock Type** | **Corn Ethanol** | | **Soy-based Biodiesel** | | **Corn Stover Ethanol** | | **Switchgrass Ethanol** | |
|---|---|---|---|---|---|---|---|---|
| | **mmHead** | **% change** | **mmHead** | **% change** | **mmHead** | **% change** | **mmHead** | **% change** |
| Dairy | -0.02 | -0.31% | -0.01 | -0.17% | 0.00 | -0.01% | -0.02 | -0.36% |
| Beef | 0.09 | 0.14% | -0.11 | -0.18% | 0.95 | 1.56% | 0.21 | 0.34% |
| Poultry | -58.84 | -0.79% | -58.84 | -0.79% | -58.84 | -0.79% | -58.84 | -0.79% |
| Swine | -0.22 | -0.17% | 0.24 | 0.19% | 9.15 | 7.27% | 7.80 | 6.20% |

Enteric fermentation emissions increase across fuel pathway scenarios with the exception of the soybean biodiesel scenario. Cattle numbers increase under the corn ethanol, corn stover ethanol, and switchgrass ethanol scenarios. Cattle are ruminants, and therefore, increase in cattle number results in increased CH4 emissions (Table 2.4-12). Cattle number decreases under the soy-based biodiesel scenario, resulting in decreased methane emissions due to enteric fermentation.

**Table 2.4-12. Change in Domestic Livestock Emissions by Scenario, 2022**

| | **Corn Ethanol** | **Soybean Biodiesel** | **Corn Stover Ethanol** | **Switchgrass Ethanol** |
|---|---|---|---|---|
| Enteric $CH_4$ Emissions (‘000 tons $CO_2$e) | 21 | -128 | 1,129 | 338 |
| Manure $CH_4$ and $N_2O$ Emissions (‘000 tons $CO_2$e) | -94 | -5 | 2,194 | 1,751 |
| *Total Livestock Emissions (‘000 tons $CO_2$e)* | *-73* | *-133* | *3,322* | *2,089* |

Use of DGS has been shown to decrease methane produced from enteric fermentation if replacing corn as animal feed. This is due to the fact that the DGS are a more efficient feed source. Consistent with our assumptions regarding the efficiency of DGS as an animal feed in our agricultural sector modeling, we have also included the enteric fermentation methane reductions of DGS use in our final rule analysis. Based on default factors in GREET, the model assumed a decrease in CH4 (-3,381 g CO2e/mmBTU ethanol) per head of cattle and cows that were fed with DGS. The reduction in CH4 is based on the same Argonne report used to determine DGS feed replacement efficiency (discussed in RIA Chapter 5). This assumption resulted in a reduction in the lifecycle GHG emissions for corn ethanol compared to the proposal assumptions.

The management of livestock manure can also produce anthropogenic CH4 and N2O emissions. CH4 is produced by the anaerobic decomposition of manure. N2O is produced through the nitrification and denitrification of the organic nitrogen in livestock manure and urine. The type of manure management methods impacts the quantity of GHG emissions emitted.

FASOM bases manure management emissions calculations on emissions factors for livestock types and livestock management methods as reported in the EPA GHG inventory report for 1990–2003.[518] Manure management emissions are projected to decrease as a result of lower livestock herd values.

Under the corn ethanol and soybean biodiesel scenario, manure-associated GHG emissions slightly decrease. Under the corn stover and switchgrass scenarios, swine production markedly increases leading to an increase in total livestock emissions (Table 2.4-12).

### 2.4.2.5 Domestic Agriculture Sector Results (Excluding Land Use Change)

Table 2.4-13 provides a summary of FASOM projections for total GHG emissions impacts for the domestic agricultural sector for each fuel pathway scenario analyzed. Land use change impacts are discussed in Section 2.4.4.

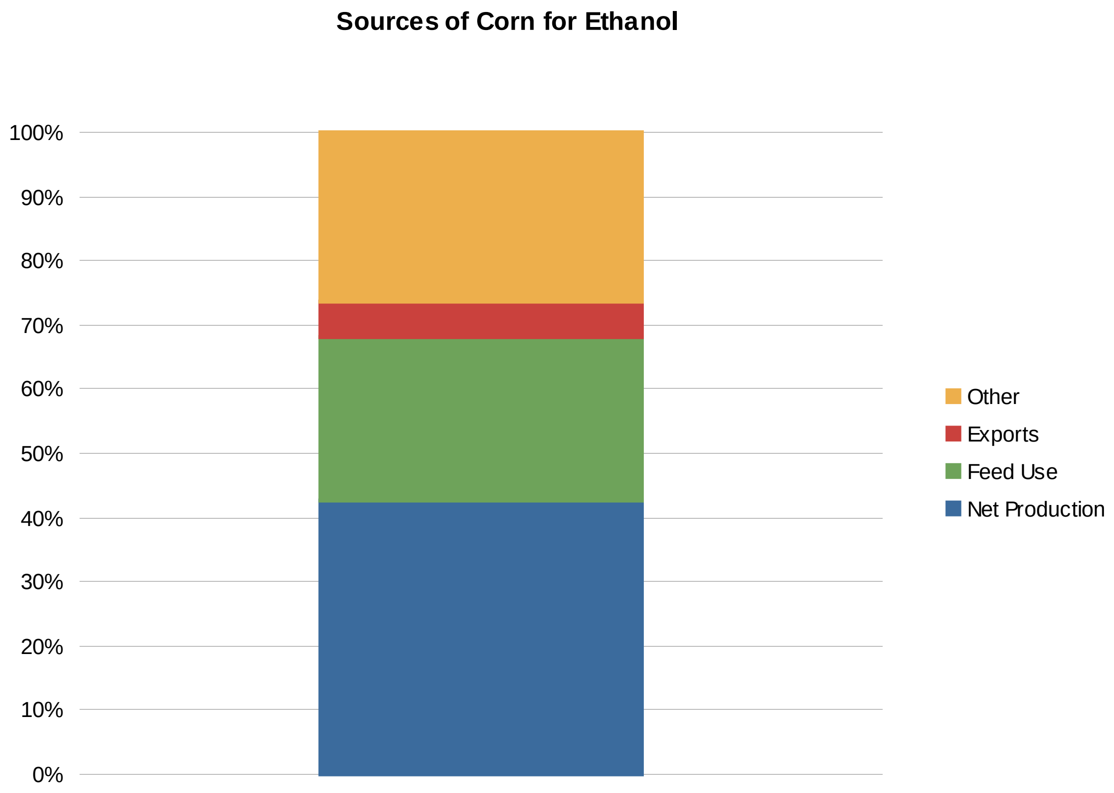
**Table 2.4-13.**
**Domestic Agriculture GHG Emission Changes by Scenario, 2022**
**(g CO2e/mmBTU)**

| **Emission Source** | **Corn Ethanol** | **Soybean Biodiesel** | **Corn Stover Ethanol** | **Switchgrass Ethanol** |
|---|---|---|---|---|
| Fuel and Feedstock Transport | 4,265 | 3,461 | 2,418 | 2,808 |
| Farm Inputs | 10,313 | 6,482 | 2,770 | 4,890 |
| Livestock (Manure and Enteric Fermentation) | -3,746 | -2,100 | 9,086 | 3,462 |
| Rice Methane | -209 | -7,950 | 434 | -1,555 |
| **Total Domestic Agriculture** | **10,623** | **-107** | **14,708** | **9,605** |

With the exception of soybean biodiesel, FASOM projects that increased biofuel production in 2022 in the scenarios analyzed will lead to increased GHG emissions in the domestic agricultural sector, excluding land use change. With increased volumes of each biofuel, fuel and feed transport and farm inputs increase and thereby increase GHG emissions. No one domestic agricultural sector emission source (excluding land use change) emerges as the specific driver of GHG emissions across all fuel pathway scenarios. Rather, emission sources act with varying degrees of importance in each scenario.

Overall the small impact in the domestic agricultural sector is due to the indirect effects and demand changes, specifically demand changes in U.S. exports. For example, the sources of corn used in ethanol production in the FASOM model are shown in Figure 2.4-9. Some of the additional corn comes from increased corn production; however, the increase in corn acres is mostly offset by reductions in other crop acres as shown in Figure 2.4-10. Some of the corn used for ethanol comes from decreased corn used for feed. During the corn ethanol production process, one of the byproducts produced are distillers grains with solubles (DGS). DGS can be used as a feed source for beef cattle, dairy cows, swine and poultry, and partially offsets the use of corn directly as feed.

**Figure 2.4-9.**



However, as seen from Figure 2.4-9, one of the sources of corn for ethanol production is projected to come from reductions in corn exports. Therefore, the domestic agricultural sector impacts are only a portion of the total impacts due to increased ethanol production in the U.S. The change in corn and other crop exports will have impacts on the international agricultural sector that need to be accounted for when determining lifecycle GHG impacts of biofuel production in the U.S.

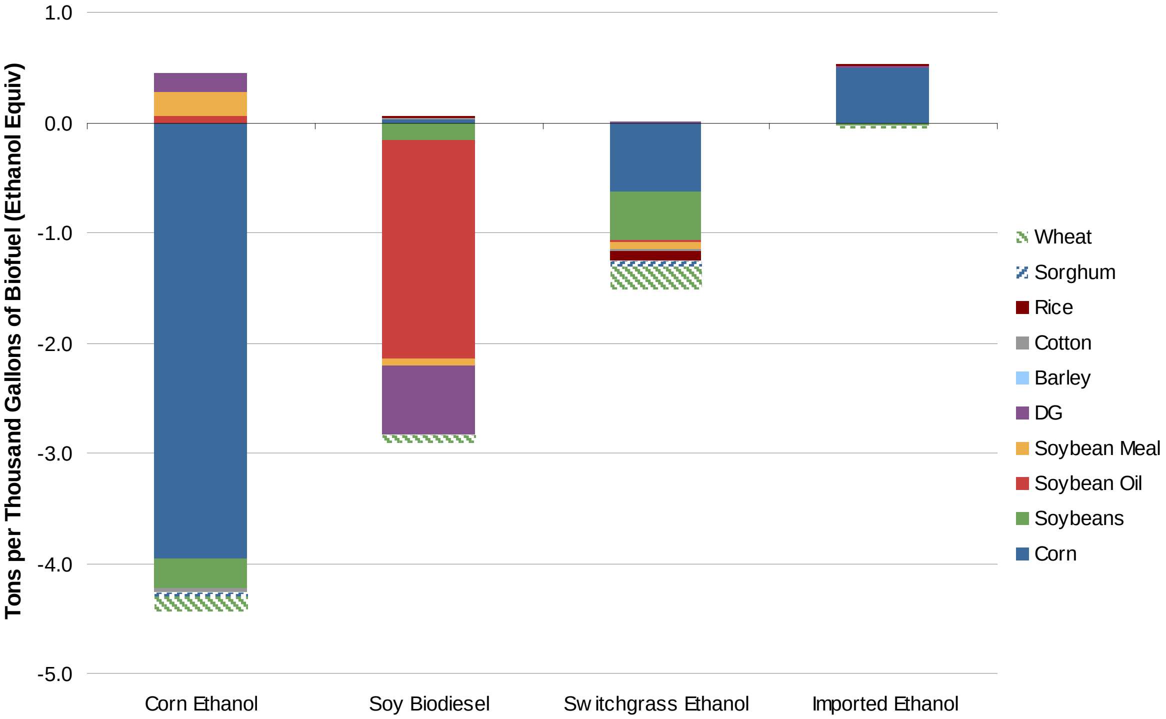
### 2.4.2.5 Translation of Domestic Impacts into International Impacts

In order to estimate the impact on international agricultural sector GHG emissions, the FAPRI-CARD model was run with the same domestic biofuel volume scenarios, with the exception of cellulosic ethanol, as was run in the FASOM model for the domestic agriculture sector analysis. In the FAPRI-CARD models, links between the U.S. and international models are made through commodity prices and net trade equations. In general, for each commodity sector, the economic relationship that quantity supplied equals quantity demanded is achieved through a market-clearing price for the commodity. In each country domestic prices are modeled as a function of the world price using a price transmission equation. Since econometric models for each sector can be linked, changes in one commodity sector will impact the other sectors.

The model for each commodity consists of a number of countries/regions, including a rest-of-the-world aggregate to close the model. The models specify behavioral equations for production, use, stocks, and trade between countries/regions. The models solve for representative world prices by equating excess supply and demand across countries. Using price transmission equations, the domestic price for each country is linked with the representative world price through exchange rates. It is through changes in world prices that change in worldwide commodity production and trade is determined.

When analyzing the impact of the RFS2 biofuel requirements in the U.S., there are two primary domestic effects that directly affect a commodity's worldwide use and trade: change in exports, and changes in domestic U.S. prices. For example, as discussed above, the corn ethanol biofuel requirement places an additional demand for corn used for ethanol, and this corn comes not just from additional production, but also from decreases in other uses including exports. In addition, as corn production expands, it places pressure in terms of relative demand on other crops in a particular region in the U.S., which in turn affects their prices and use (including exports). As the level of exports from the U.S. of a particular commodity decreases, other countries will adjust their production and trade to satisfy the demand for that commodity. Figure 2.4-10 shows the change in U.S. exports per by major commodity per thousand gallons of biofuel, as projected by FASOM.

**Figure 2.4-10. Normalized Changes in U.S. Exports by Crop, 2022**
**(tons per thousand gallons of renewable fuel)**



As expected, an increase of a particular biofuel will have the greatest impact on U.S. exports of that biofuel's feedstock. For instance, with an increase of one thousand gallons of corn ethanol, corn exports decrease by four tons, and with an increase of one thousand gallons of soy biodiesel, soybean oil exports decrease by two tons. Increases in corn ethanol and soy biodiesel will not only affect the crop area and export levels of its primary feedstock (corn and soybean oil, respectively), but it will also affect other crops as increased demand for these commodities change the relative demand, and therefore production and use, between different commodities.

Although switchgrass and other cellulosic ethanol sources are not explicitly modeled in FAPRI-CARD, the changes in acres for various crops as a result from an increase in switchgrass ethanol as modeled by FASOM were applied to FAPRI-CARD on a regional basis in the U.S. This provides a reasonable approximation of the effects of an increase of switchgrass acres in the FAPRI-CARD model, and the affect it has on other crop area, production, prices and trade for other crops.

In addition, we have modeled the impact of increased production of Brazilian sugarcane ethanol for use in the U.S. market. The FAPRI-CARD model has been used to determine the international impacts of Brazilian sugarcane ethanol production. The increase in Brazilian sugarcane ethanol production is assumed to have no impacts on domestic U.S. agriculture emissions.

As well as the change in U.S. exports, the FAPRI-CARD model relies on price transmission equations, therefore changes in the U.S. price for a commodity will have a direct impact on the world price for that commodity. This, in turn, will have an impact on the demand for that commodity worldwide, and affect production and trade levels in other countries. Additional information on the changes in the world price for commodities and the coordination of assumptions between the FASOM and FAPRI-CARD models can be found in Chapter 5 of the RIA.

### 2.4.3 Evaluation of International Agricultural GHG Emissions Impacts

For this analysis we used the FAPRI-CARD model to estimate the impacts on international crop production due to changes in biofuel production. These results were used to generate GHG emissions from the international agricultural sector, similar to what was done to determine domestic agricultural GHG emission changes.

#### 2.4.3.1 International Agricultural Inputs

The FAPRI-CARD model does not directly provide an assessment of the GHG impacts of changes in international agricultural practices (e.g., changes in fertilizer load and energy use). However, it does predict changes in crop area and production by crop type and country. We, therefore, determined international fertilizer and energy use based on data collected by the Food and Agriculture Organization (FAO) of the United Nations and the International Energy Agency (IEA). For the final rule, we have also incorporated more up-to-date fertilizer consumption statistics provided by a recent International Fertilizer Industry Association (IFA) report, Assessment of Fertilizer Use by Crop at the Global Level, 2006/07 – 2007/08.[519] For more details refer to the memorandum to EPA from ICF International.[520] Where country and crop specific energy use data was available (in the case of Brazilian sugarcane), we used that data as further discussed in Section 2.4.3.3.

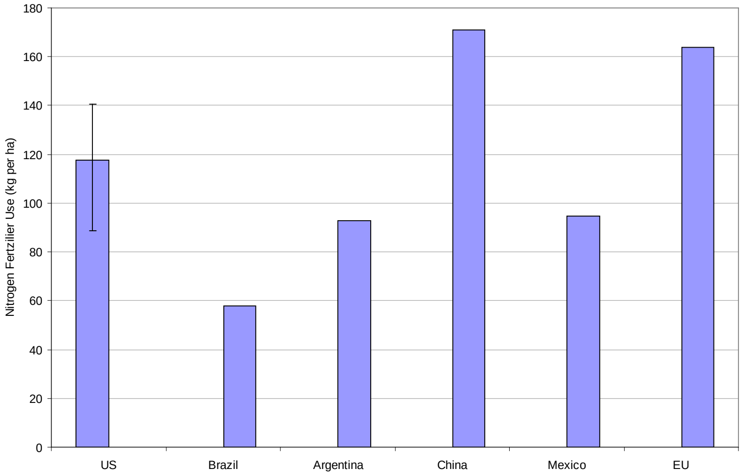
We took the FAPRI-CARD provided activity data on changes in crop acres, by crop and country, and multiplied by regional fertilizer use rate factors (kg per ha) to determine the global impacts of biofuel production on fertilizer application. Historical fertilizer application rates for nitrogen, phosphorus, and potassium were updated using more recent data available from the IFA report as recommended by expert reviewers during our peer review.[521] IFA data are preferred over FAO's Feristat data because estimates are more current and years of available data are consistent across all countries. Also, FAO has altered its survey methodology since 2004.[522]

The IFA dataset covers 23 countries (considering the European Union-27 as one country) and 11 crop groups including: wheat, rice, corn, other coarse grains, soybean, palm oil, other oilseeds, cotton, sugar crops, fruits and vegetables, and other crops. IFA consumption data were averaged over the two reported time periods: 2006 or 2006/07, and 2007 or 2007/08 to account for seasonal variations in crop production. Fertilizer application rates were calculated by dividing IFA total consumption values by FAOStat agricultural area harvested data from the FAOStat database.[523]

The FAO Feristat dataset was also updated to the most recent version since the proposal. Feristat data are used for country/crop and region/crop combinations not covered by the IFA dataset. In addition, Feristat data is preferred to calculate fertilizer consumption for "rest of the world" regions since the dataset provides for a greater number of countries and greater detail for a variety of crops. Feristat fertilizer application rates (kg per ha) are calculated by dividing total Feristat fertilizer consumption by Feristat agricultural area fertilized.

Figure 2.4-11 compares the nitrogen fertilizer application rates for major corn produces around the word as determined with IFA and FAO data, with the U.S. as a reference for comparison.

**Figure 2.4-11.**
**Nitrogen Application Rates for Corn in Select Regions**



Herbicide and pesticide use data have been updated using the most current data available from FAO's FAOStat dataset for pesticide consumption.[524] FAO's pesticide consumption dataset did not provide values for China, and thus data was used from the U.S. Department of Agriculture's (USDA) Economic Research Service (ERS).[525]

We acknowledge that there may be other country and crop specific sources of fertilizer data available for example for Brazilian sugarcane in addition to the IFA data, however, it was not available in time for incorporation in the final rule analyses and furthermore the data used provides a consistent dataset for all crops and countries.[526] This is an area for future research for any future analysis.

IFA does not collect data on lime use, however for the final rule we include lime use for sugarcane based on data from Macedo (2008), estimated at 333.3 kg/ha.

We then used GREET factors for emissions from production of agricultural chemicals to estimate the upstream GHG impacts of fertilizer and chemical production to calculate total impacts for each fuel scenario with the exception of lime where we used data from Macedo to represent lime production in Brazil. Table 2.4-14 provides the total change in fertilizer and chemical use for the different fuel scenarios, per mmBTU renewable fuel.

**Table 2.4-14.**
**International Change in Fertilizer and Chemical Use by Scenario, 2022**
**(kg/mmBTU)**

| **Input** | **Corn Ethanol** | **Soy-Based Biodiesel** | **Switchgrass Biochemical Ethanol** | **Sugarcane Ethanol** |
|---|---|---|---|---|
| N Application | 0.3683 | 0.0526 | 0.0774 | 0.4451 |
| P Application | 0.1780 | 0.6216 | 0.1302 | 0.1520 |
| K Application | 0.1245 | 0.6288 | 0.1179 | 0.5735 |
| Herbicide Application | 0.0006 | 0.0021 | 0.0006 | 0.0006 |
| Pesticide Application | 0.0009 | 0.0024 | 0.0008 | 0.0008 |

### 2.4.3.2 International N2O Emissions

For international N2O emissions we considered both direct and indirect emissions from synthetic fertilizer application, crop residue N, and manure management. Manure management emissions are discussed in the following section. Direct and indirect emissions from synthetic fertilizer application and crop residues were calculated based on IPCC guidance as shown in Table 2.4-15.[527]

## Table 2.4-15. Calculations of N2O Emissions from Synthetic Fertilizer and Crop Residues

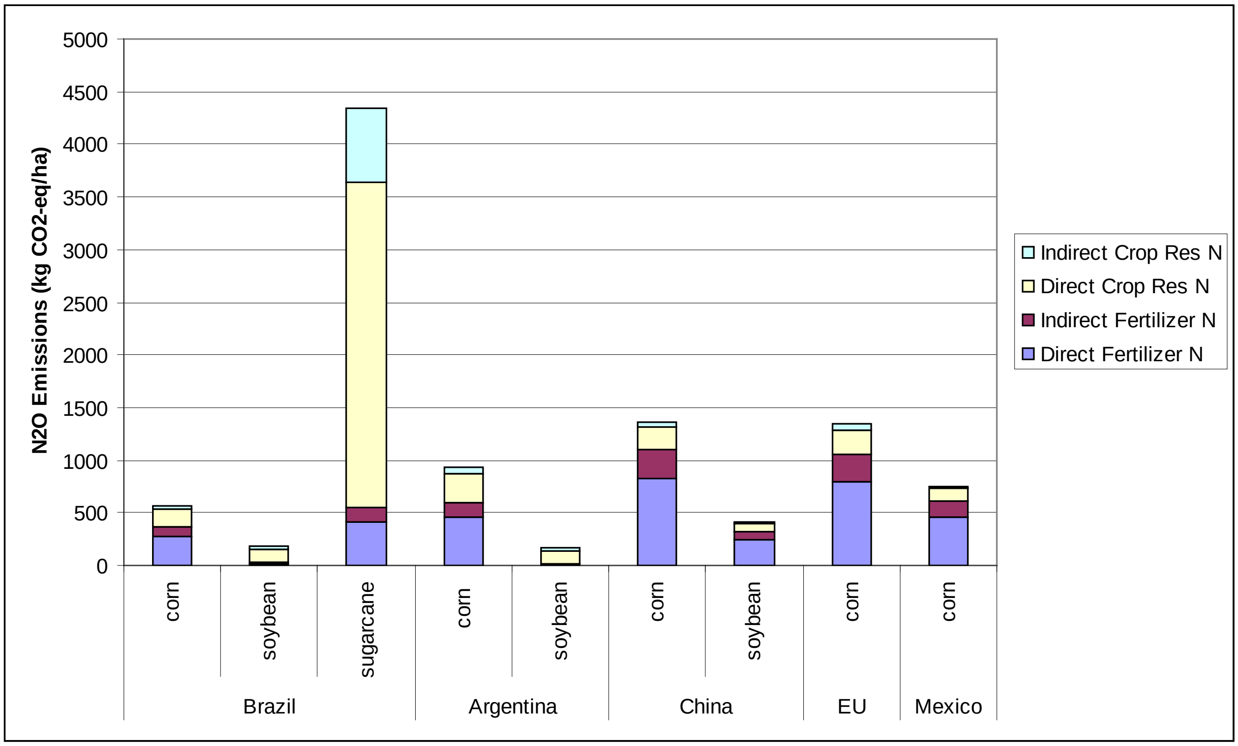
| | | |
|---|---|---|
| **Direct $N_2O$ Emissions** | | |
| **Direct Emissions (Overall Equation)** | | **Equation** |
| Emissions | = | (N additions to soils from mineral fertilizer + N additions to soils from crop residues) × EF |
| EF for N additions from mineral fertilizer and crop residues | = | 0.01 kg $N_2O$-N / kg N added |
| **N Additions from Mineral Fertilizers** | | |
| N additions to soils from mineral fertilizers | = | Kg fertilizer N applied to soils (i.e., change in fertilizer N applications from Table 2.4-14) |
| **N Additions from Crop Residues** | | |
| N additions to soils from crop residues | = | above-ground residue dry matter × Crop Area × [N content of aboveground residues + ratio of belowground residues to aboveground biomass × N content of belowground residues] |
| *where,* | | |
| Above-ground residue dry matter and N additions to soils from crop residues | = | Taken from IPCC default values by crop |
| **Indirect $N_2O$ Emissions** | | |
| *Note that for indirect emissions, the calculation of N applied to soils from fertilizers or crop residues is the same as for direct emissions* | | |
| **Indirect Emissions from Volatilization** | | **Equation** |
| Emissions | = | N additions to soils from mineral fertilizers × N lost through volatilization × EF |
| N lost (from synthetic fertilizer additions) through volatilization | = | 0.1 (kg $NH_3$–N + NOx–N) / kg N applied |
| EF for N lost through volatilization | = | 0.010 kg $N_2O$–N / (kg $NH_3$–N + $NO_X$–N volatilised) |
| **Indirect Emissions from Leaching/Runoff** | | **Equation** |
| Emissions | = | (N additions to soils from mineral fertilizers + N additions to soils from crop residues) × N lost through leaching or runoff × EF |
| N lost through leaching/runoff (from all N sources) | = | 0.3 N losses by leaching or runoff / kg N addition |
| EF for N lost through leaching/runoff | = | 0.0075 kg N20-N / kg N leaching or runoff |

The proposal did not include N2O emissions from the Direct and Indirect Emissions from Crop Residues for cotton, palm oil, rapeseed, sugar beet, sugarcane, or sunflower. These were not included for these crops because default crop-specific IPCC factors used in the calculation were not available.

Comments from our peer review process suggested that we include proxy emissions from these crops based on similar crop types that do have default factors. Therefore, for our final rule analysis we have included crop residue N2O emissions from sugarcane production based on perennial grass as a proxy. Perennial grass is chosen as a proxy based on input from N2O modeling experts. Emissions for cotton, palm oil, rapeseed, sugar beet, and sunflower were also included based on root crops, other as a proxy.

Figure 2.4-12 summarizes N2O emissions by crop for a sample of crops and countries by the four categories of N2O emissions.

**Figure 2.4-12. Sources of N2O Emissions by Crop for Select Regions**



Based on the equations in Table 2.4-15 and the crop production changes projected by FAPRI-CARD, we estimated the total change in N2O emissions for each fuel scenarios, as shown in Table 2.4-16.

**Table 2.4-16.**
**International Crop Change in N2O Emissions in 2022 from Different Fuel Scenarios**
**(kg CO2e/mmBTU)**

| | Corn Ethanol | Soybean Biodiesel | Switchgrass Ethanol | Brazilian Sugarcane Etanol |
|---|---|---|---|---|
| Direct and Indirect $N_2O$ Emissions | 3.38 | 2.09 | 0.95 | 29.25 |

### 2.4.3.3 International Fuel Combustion Emissions

In terms of evaluating international agriculture energy use data, we continued to use IEA data as these are the best available for this purpose (providing data by end use and fuel type for over 130 countries representing the major energy users of the world). We collected data from IEA on total CO2 emissions from agricultural fuel combustion by country.[528] We also collected IEA data on agricultural electricity and fuel use by country, which was combined with emissions factors to estimate country-level GHG emissions from agricultural electricity and fuel use. Historical trends were used to project chemical and energy use in 2022. These total GHG emissions were only combustion related, so we scaled them to represent full lifecycle GHG emissions from fuel production, based on the ratio of combustion to full lifecycle GHG emissions from U.S. fuel and electricity use. Country-level GHG emissions from agricultural energy use were then divided by the area of agricultural land in each country, from the FAOSTAT land area database to derive a per acre GHG emissions factor from agricultural energy use by country. Our estimates use average energy consumption and GHG emissions per acre for all crops in each foreign country. We multiplied these agricultural energy consumption emissions factors by the country-level crop acreage changes projected by FAPRI-CARD to determine the change in GHG emissions from foreign agricultural energy use for each fuel scenario.

In the case of Brazilian sugarcane, we had country and crop specific data available to estimate agricultural energy use.[529] For sugarcane farming, energy use includes the diesel fuel used to power farming equipment and energy use for sugarcane preparation. The energy used to perform other activities and small services during productive operation was also included. Energy embedded in farming equipment was not included in this calculation, as consistent with other renewable fuel pathways. Table 2.4-17 shows how diesel consumption is expected to increase in the future mainly due to increased use of diesel consumption with the growth of mechanical harvesting and trash recovery.

**Table 2.4 17. Energy Use (BTU/MT sugarcane)**[UUUUUU]

| Activity | 2002 | 2005/2006 | 2020 |
|---|---|---|---|
| Ag Operations | 15544 | 12606 | 14028 |
| Harvesting | 20568 | 31562 | 44453 |
| Other Activities | | 36491 | 42462 |
| Seeds | 5592 | 5592 | 6256 |
| Total | 41704 | 86251 | 107198 |

---

[UUUUUU] Converted from Macedo (2008) Table 9.

For the final rule we assumed the energy use estimated in 2020 for agricultural operations, harvesting, other activities and seed production would be similar to that in 2022, and have adopted these estimates for our GHG calculations for the case where 40% of the trash (sugarcane leaves and tops) are assumed to be collected as predicted in literature. When trash is not assumed to be collected, we used 2005/2006 energy use data to account for the fact that less energy use would be required as the collection of trash is not needed. We assume the energy use is from 100% diesel.

Table 2.4-18 provides the total change in agricultural energy use GHG emissions for the different fuel scenarios.

**Table 2.4-18.**
**International Change in Agricultural Energy Use GHG Emissions by Scenario, 2022 (kg CO2e / mmBTU)**

| | **Corn Ethanol** | **Soybean Biodiesel** | **Switchgrass Ethanol** | **Brazilian Sugarcane Ethanol** |
|---|---|---|---|---|
| Agricultural Sector Energy Use GHG Emissions | 1.7 | 1.88 | -0.16 | 5.14 |

### 2.4.3.4 International Rice Methane Emissions

To estimate rice emission impacts internationally, we used the FAPRI-CARD model to predict changes in international rice production as a result of the increase in biofuels demand in the U.S. Since FAPRI-CARD does not have GHG emissions factors built into the model, we applied IPCC default factors by country.

Calculating emissions from rice cultivation, per the IPCC 2006 guidelines, requires the following data: area of rice harvested, an emissions factor, and planting to harvesting season length. Area of rice harvested by country was provided by the FAPRI-CARD results. The default IPCC emission factors were used scaled for each cropping regime: irrigated, rainfed lowland, upland and deepwater by country. Rice cultivation season lengths were available from the International Rice Research Institute (IRRI).[530]

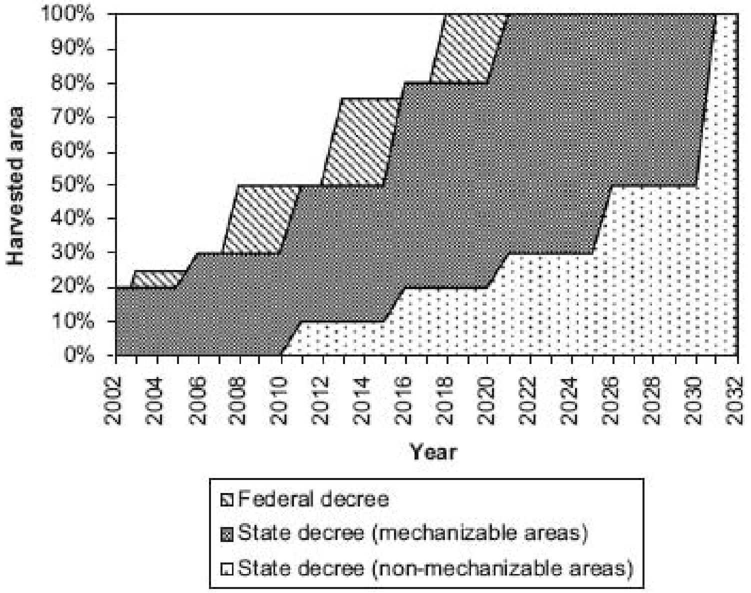
### 2.4.3.5 International Crop Residue Burning Emissions

International crop residue burning on the field, and specifically changes in residue burning emissions could occur due to changes in U.S. biofuel policy. We specifically included for the final rule analysis an estimate of sugarcane field burning and mechanical harvesting emissions. We also incorporate emissions from land clearing for crop production as discussed in Section 2.4.4.

Sugarcane leaves and tops are typically burned in the field before and after harvest. Per metric ton of sugarcane, there is 280 kg of leaves and tops (with 50% moisture content) or 140 kg of dry leaves and tops, which we assume for modeling purposes. In the case where trash is collected, it was assumed that 40% (i.e. 56 kg dry leaves and tops per metric ton of cane would be recovered to be used as fuel at the mill).

Current trends in Brazil are moving from burned cane with manual harvesting to unburned cane with mechanical harvesting. This change is related to the gradual reduction of cane trash pre-burning at both Federal and State levels in Brazil. See Figure 2.4-13 for the phase out schedule for trash burning practices.

**Figure 2.4-13. Phase Out Schedule for Trash Burning Practices**



According to Brazil's Sugarcane Research Center (CTC), about 47.5% of all sugarcane in Brazil is already mechanically harvested, and 35.3% of all sugarcane in Brazil is mechanically harvested without being burned in the field.[531] These percentages have increased since 2002, see Table 2.4-19.

**Table 2.4-19. Sugarcane Harvest –2002 Situation**

| Type of harvest | Sao Paulo (%) | Center-South (%) |
|---|---|---|
| Manual | 63.8 | 65.2 |
| Mechanical | 36.2 | 34.8 |
| Burned sugarcane | 75.0 | 79.1 |
| Unburned sugarcane | 25.0 | 20.9 |

UNICA states that in 2008 about half of the sugarcane fields in Sao Paulo were mechanically harvested, up from 36.2% in 2002. In the future, Sao Paulo state law requires that sugarcane field burning be phased-out by 2021 for areas where mechanical areas are possible with existing technologies (over 85% of existing sugarcane fields) and where mechanical harvesting may not be possible, 30% will be required to phase-out burning. This implies that by 2022 considering all areas in Sao Paulo about 90% of sugarcane fields could be unburned.

Sao Paulo currently accounts for 60% of all national production of sugarcane, with the Center-South producing about 89% of all sugarcane. Considering that 89% of Brazilian Production occurs in the Center-South, and Sao Paulo consists of a considerable portion of that production, the following situation in Table 2.4-20 as assumed for Brazil in 2022.

**Table 2.4-20.**
**Sugarcane Harvest – Projected for 2022**

| **Type of harvest** | **Brazil (%)** |
|---|---|
| Manual | 0 |
| Mechanical | 100 |
| Burned sugarcane | 10 |
| Unburned sugarcane | 90 |

We took into account emissions from open-field burning from two pollutants, methane (CH4) and nitrous oxide (N2O). Carbon dioxide (CO2) emissions were not taken into account because the CO2 is considered to be taken from the air during sugarcane growth.

**Table 2.4-21.**
**Emission Factors of Open-Field Burning of Sugarcane Leaves and Tops**[532]

| **Pollutant** | **g/kg of dry leaves and tops burned** |
|---|---|
| $CH_4$ | 2.7 |
| CO | 92 |
| $N_2O$ | 0.07 |
| $NO_x$ | 2.5 |
| $PM_{10}$ | 7.8 |
| $PM_{2.5}$ | 3.9 |
| $SO_x$ | 0.4 |
| VOC | 7.0 |

### 2.4.3.6 International Livestock GHG Emissions

Similar to domestic livestock impacts associated with an increase in biofuel production, internationally the FAPRI-CARD model predicts changes in livestock production due to changes in feed prices. The GHG impacts of these livestock changes, enteric fermentation and manure management GHG emissions, were included in our analysis. Unlike FASOM, the FAPRI-CARD model does not have GHG emissions built in and, therefore, livestock GHG impacts were based on activity data provided by the FAPRI-CARD model (e.g., number and type of livestock by country) multiplied by IPCC default factors for GHG emissions.

Table 2.4-22 shows the changes in livestock predicted by the FAPRI-CARD model in 2022 for each of the fuel scenarios considered.

## Table 2.4-22.
## Foreign Livestock Changes by Region and Renewable Fuel, 2022
## (head / billion BTU)

| **Corn Ethanol** | Dairy | Beef | Swine | Sheep | Poultry |
|---|---|---|---|---|---|
| Canada | 0.00 | 0.05 | -0.17 | 0.00 | 1.37 |
| Western Europe | 0.00 | -0.07 | 0.12 | 0.02 | 1.58 |
| Eastern Europe | 0.00 | -0.83 | 0.01 | 0.00 | 17.72 |
| Oceania | -0.02 | 0.11 | 0.01 | 0.07 | 3.53 |
| Latin America | -0.15 | 3.44 | 0.48 | 0.00 | -0.46 |
| Asia | -0.09 | 0.17 | -0.04 | -1.19 | -1.53 |
| Africa and Middle East | -0.03 | -0.45 | 0.32 | 0.00 | -3.01 |
| Indian Subcontinent | 0.00 | 0.12 | 0.02 | 0.00 | -3.66 |
| **Soy-Based Biodiesel** | Dairy | Beef | Swine | Sheep | Poultry |
| Canada | 0.02 | 0.27 | 1.62 | 0.00 | -8.07 |
| Western Europe | -0.01 | 0.57 | -1.16 | -0.45 | 29.30 |
| Eastern Europe | 0.00 | -0.59 | -0.44 | 0.00 | -114.88 |
| Oceania | 0.05 | 0.03 | 0.11 | -0.20 | -30.92 |
| Latin America | 0.45 | -8.38 | 0.18 | 0.00 | -0.06 |
| Asia | 0.33 | 0.92 | 0.60 | 6.67 | -55.37 |
| Africa and Middle East | 0.01 | 2.11 | 0.82 | 0.00 | 2.65 |
| Indian Subcontinent | 0.00 | 0.27 | 0.06 | 0.00 | -34.31 |
| **Sugarcane Ethanol** | Dairy | Beef | Swine | Sheep | Poultry |
| Canada | 0.00 | 0.00 | -0.10 | 0.00 | 0.47 |
| Western Europe | 0.00 | -0.01 | 0.07 | 0.01 | -0.32 |
| Eastern Europe | 0.00 | -0.12 | 0.02 | 0.00 | 4.56 |
| Oceania | 0.00 | 0.01 | -0.01 | 0.00 | 0.96 |
| Latin America | -0.03 | 0.22 | -0.08 | 0.00 | -0.09 |
| Asia | -0.01 | -0.01 | -0.14 | -0.32 | 0.13 |
| Africa and Middle East | -0.01 | 0.00 | -0.06 | 0.00 | -0.58 |
| Indian Subcontinent | 0.00 | -0.01 | 0.00 | 0.00 | -0.43 |
| **Switchgrass Ethanol (Biochemical)** | Dairy | Beef | Swine | Sheep | Poultry |
| Canada | 0.00 | 0.00 | -0.11 | 0.00 | 0.72 |
| Western Europe | 0.00 | -0.01 | 0.06 | 0.02 | -0.34 |
| Eastern Europe | 0.00 | -0.12 | 0.05 | 0.00 | 6.36 |
| Oceania | 0.00 | 0.02 | 0.00 | 0.00 | 1.10 |
| Latin America | -0.03 | 0.04 | 0.07 | 0.00 | -0.11 |
| Asia | -0.02 | 0.00 | 0.13 | -0.47 | 0.48 |
| Africa and Middle East | -0.01 | 0.05 | 0.03 | 0.00 | -0.77 |
| Indian Subcontinent | 0.00 | -0.01 | 0.00 | 0.00 | -0.44 |

The enteric fermentation GHG impacts of livestock changes were calculated by applying regional default factors for enteric fermentation CH4 emissions by livestock type. These factors are shown in Table 2.4-23.

**Table 2.4-23. Enteric Fermentation Emission Factors**

| Enteric Fermentation (kg $CH_4$/head/year) | Dairy | Cattle | Swine | Sheep |
|---|---|---|---|---|
| North America | 121 | 53 | 1.5 | 8 |
| Western Europe | 109 | 57 | 1.5 | 8 |
| Eastern Europe | 89 | 58 | 1.5 | 8 |
| Oceania | 81 | 60 | 1 | 5 |
| Latin America | 63 | 56 | 1 | 5 |
| Asia | 61 | 47 | 1 | 5 |
| Africa and Middle East | 40 | 31 | 1 | 5 |
| Indian Subcontinent | 51 | 27 | 1 | 5 |

Manure management GHG impacts of livestock changes for each fuel scenario were calculated by applying regional default factors for manure management CH4 and N2O emissions by livestock type. Manure management CH4 emission factors are shown in Table 2.4-24. Manure management N2O values were based on default IPCC nitrogen produced per livestock type and IPCC default manure management practices by region.

**Table 2.4-24. Manure Management Methane Emission Factors**

| Manure Management (kg $CH_4$/head - year) | Dairy | Cattle | Swine | Sheep | Poultry |
|---|---|---|---|---|---|
| North America | 78 | 2 | 23.5 | 0.28 | 0.02 |
| Western Europe | 51 | 15 | 15.5 | 0.28 | 0.02 |
| Eastern Europe | 27 | 13 | 6.5 | 0.28 | 0.02 |
| Oceania | 29 | 2 | 18 | 0.15 | 0.02 |
| Latin America | 1 | 1 | 1 | 0.15 | 0.02 |
| Asia | 18 | 1 | 4 | 0.15 | 0.02 |
| Africa and Middle East | 1.5 | 1 | 2 | 0.15 | 0.02 |
| Indian Subcontinent | 5 | 2 | 4 | 0.15 | 0.02 |

Based on the peer review of the methodology used for the proposal it was determined that the calculations for manure management did not include emissions from soil application. These emissions were included for our final rule analysis but do not cause a significant change in the livestock GHG emission results.

### 2.4.3.7 International Agriculture Sector Results (Excluding Land Use Change)

Table 2.4-25 provides an overview of the total GHG emissions impacts from the international agricultural sector based on the results of the FAPRI-CARD modeling. As discussed above, emissions from farm inputs include the production, transport and fate of agricultural inputs including pesticide, fertilizer and other chemicals. The farm inputs category also includes energy used in crop production processes. Land use change impacts are discussed in Section 2.4.4.

### Table 2.4-25.
### Foreign Agriculture GHG Emission Changes in 2022 from Different Fuel Scenarios (g CO2e/mmBTU)

| | Corn Ethanol | Soy Biodiesel | Sugarcane Ethanol | Switchgrass Ethanol |
|---|---|---|---|---|
| Farm Inputs | 6,601 | 5,402 | 37,884 | 1,310 |
| Livestock Production | 3,458 | -6,436 | -128 | -245 |
| Rice Methane | 2,089 | 2,180 | 485 | -920 |

### 2.4.4 Land Conversion GHG Emissions Impacts

Our lifecycle GHG estimates include emissions from domestic and international land use conversions induced by increased renewable fuels consumption in the United States. To estimate land conversions GHG emissions we answered six key questions:

1. How much land is converted?
2. Where does land conversion occur?
3. What types of land are converted?
4. What are the GHG emissions impacts from that land conversion?
5. How do we account for the variable timing of land conversion GHG releases?
6. What is the level of uncertainty in our land conversions GHG emissions estimates?

This section describes our approach for answering these questions about land use change. We used the FASOM model to project land conversions in the United States. FASOM was designed to simulate domestic land use interactions and land use change GHG impacts. We used the FAPRI-CARD model to project international cropland expansion in response to increased United States biofuel consumption. We used the FAPRI-CARD international models to project changes in the area of land used for crop production and pasture. FAPRI-CARD does not, however, project which types of land would be cleared to make room for additional agricultural land uses, or where within in each country or region agricultural expansion would likely take place. To fill this information gap we used MODIS satellite data provided by Winrock International, Inc. (from now on referred to as Winrock), that shows recent land use change patterns from 2001 to 2007. To determine the GHG impacts of the projected land conversions we applied GHG emissions factors prepared by Winrock following IPCC guidelines. To account for the variable timing of land use change GHG impacts, we annualized land use change GHG impacts over 30 years (with a 0% discount rate).

To quantify the uncertainty in our quantification of GHG emissions from international land conversions, we focused on two areas: uncertainty in the MODIS satellite data used to determine the types of land affected (e.g., forest or grassland), and uncertainty in the our land conversion GHG emissions factors (i.e., the GHG emissions per unit area of land conversion). To reduce and quantify the uncertainty in the MODIS satellite data we utilized extensive data validation efforts by NASA, which we used to correct systematic errors in the MODIS data set and to quantify the remaining uncertainty. To quantify the uncertainty in land conversion GHG emissions factors, we evaluated the uncertainty in every data input based on the quality, quantity, resolution and variability in the underlying data sources. Correlation groups were assigned based on the sources of underlying data. Finally, the total uncertainty in international land use change GHG emissions was quantified a Monte Carlo analysis following Tier 2 IPCC guidelines.

This section describes the data sources and methods used for the analysis summarized above, with key results illustrated throughout.

### 2.4.4.1 Evaluation of Domestic Land Conversion GHG Emissions Impacts

We used FASOM to project U.S. land use change under each fuel-specific pathway scenario due to the increase in respective renewable fuels and then the change in GHG emissions that result from the changes in land use. FASOM was designed to simulate land use interactions to predict the types of land converted in the U.S. (See RIA Chapter 5 for more details). In this section we discuss FASOM modeling of land conversion and related GHG emissions as well as final calculations for GHG emissions on a per mmBTU basis for each fuel-specific pathway scenario.

#### 2.4.4.1.1 Area and Location of Domestic Land Conversions

How land is used in FASOM is determined through the relative profits from various activities. This varies not only between crops, but also between different land uses, such as pasture for livestock production. A number of updates have been made to the FASOM model since the analysis for the Proposal in order to have a more complete assessment of land use in the U.S. One of these updates includes the incorporation of the forestry component of the FASOM model. Running both the forestry and agriculture components of the model for the final rulemaking analysis shows the interaction between these two sectors as they compete for land in various regions, as well as the effect on products and prices in each respective sector.

In addition, FASOM also includes a representation of seven major land use categories, including cropland, cropland pasture, forestland, forest pasture, rangeland, developed land, and acres enrolled in the Conservation Reserve Program (CRP). These categories are based on the USDA National Agriculture Statistics Service (NASS), and enable the FASOM model to explicitly link the interaction between livestock, pasture land, cropland, and forest land, as well as have a detailed accounting of acres in the U.S. across different land uses. Cropland is actively managed cropland, used for both traditional crops (e.g., corn and soybeans) and dedicated energy crops (e.g., switchgrass). Cropland pasture is managed pasture land used for livestock production, but which can also be converted to cropland production. Forestland contains a number of sub-categories, tracking the number of acres both newly and continually harvested (reforested), the number of acres harvested and converted from other land uses (afforested), as well as the amount of forest acres on public land. Forest pasture is unmanaged pasture land with varying amounts of tree cover that can be used to raise livestock. A portion of this land may be used for timber harvest. Rangeland is unmanaged land that can be used for livestock grazing production. While the amount of rangeland idled or used for production may vary, rangeland may not be used for any other purpose than for animal grazing. For each of these categories, FASOM accounts for how much is actively used in production, and how much idled, in a particular time period.

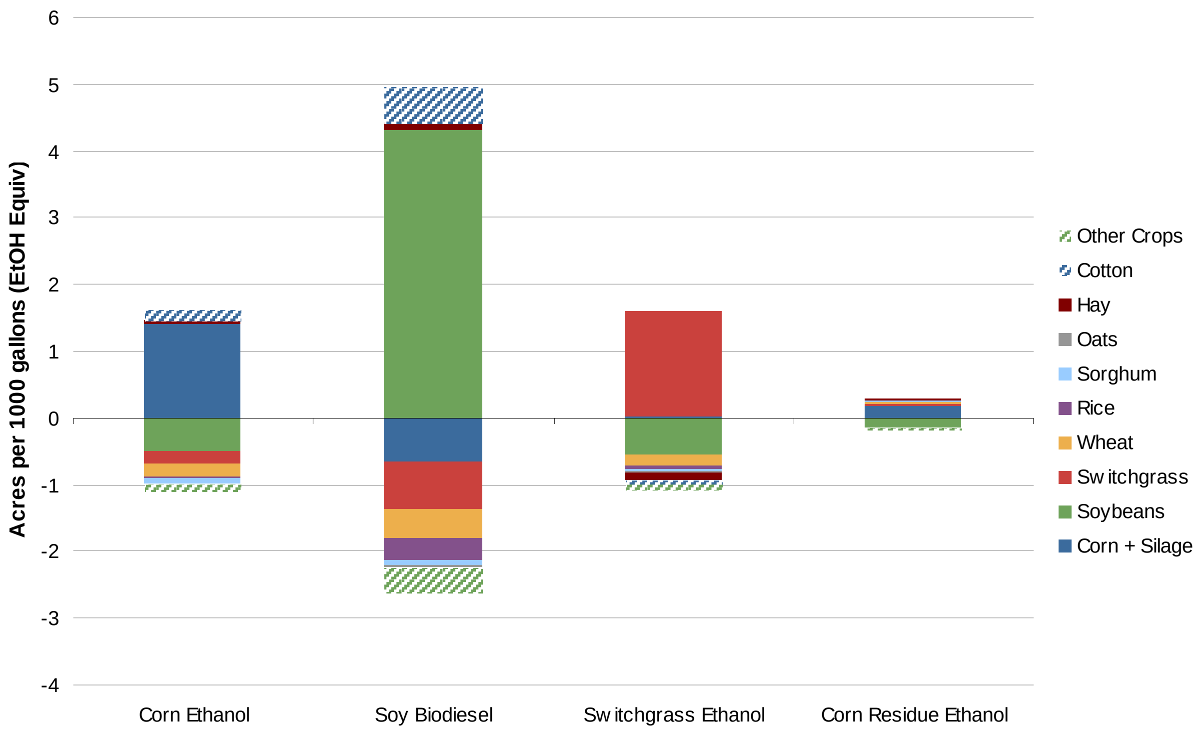
Another update to the FASOM model is the distillers grains and solubles (DGS) replacement rates for corn and soybean meal in animal feed. These replacement rates are based on recent research published by Argonne National Laboratory[533] that demonstrate higher replacement rates than what was used in the analysis for the Proposal. This means that DGS, as a byproduct of corn ethanol production, are relatively more efficient compared to the Proposal's analysis, and results in less corn and soybean meal needed for animal feed. This, in turn, results in less corn and soybean production needed for use in animal feed relative to the Proposal. Further discussion of changes made to the FASOM model can be found in Chapter 5.

For the corn ethanol scenario, the FASOM model estimates that total cropland area used for production increases by 1.4 million acres in 2022. This is a result of an increase of 3.7 million acres of corn, a decrease of 1.3 million acres in soybeans, as well as changes in other crop acres. Similarly, total cropland area increases by 1.9 million acres in the soybean biodiesel scenario, which consists of an increase of 3.5 million acres of soybeans, decreases of 0.6 million acres each of corn and switchgrass, as well as a variety of other changes. In the switchgrass ethanol scenario, total cropland acres increases by 4.2 million acres, including an increase of 12.5 million acres of switchgrass, a decrease of 4.3 million acres of soybeans, a 1.4 million acre decrease of wheat acres, a decrease of 1 million acres of hay, as well as decreases in a variety of other crops. Table 2.4-26 summarizes the change in total cropland acres used in production, both total and normalized by changes in biofuel volume, and Figure 2.4-14 shows the changes for each crop in each fuel-specific volume scenario.

**Table 2.4-26.**
**Change in total area of domestic cropland used for production by scenario, in 2022**

| Scenario | Total Cropland Increase (million acres) | Normalized Cropland Increase (acres per thousand gallons, ethanol equivalent) |
|---|---|---|
| Corn Ethanol | 1.4 | 0.12 |
| Soybean Biodiesel | 1.9 | 0.39 |
| Switchgrass Ethanol | 4.2 | 0.04 |
| Corn Stover Ethanol | 0.6 | 0.06 |

**Figure 2.4-14. Normalized Domestic Crop Acreage Changes by Scenario, 2022 (acres per thousand gallons, ethanol equivalent)**



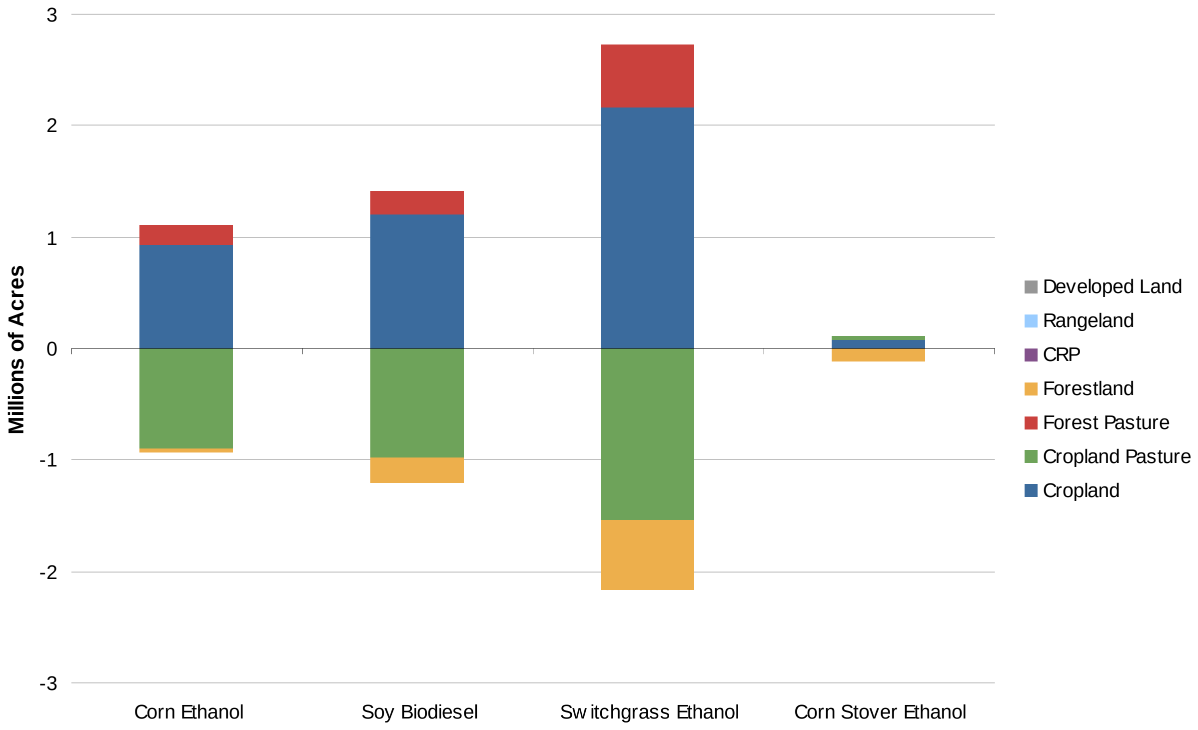
### 2.4.4.1.2 Types of Domestic Land Conversions

Based on relative demand for crop and livestock production changes that result from increased demand for biofuels, there are direct effects on land used for crop and livestock production, as well as indirect effects on other land types in the U.S. For instance, in 2022, as demand for corn ethanol increases in the corn ethanol scenario, total cropland (used for production and idled) increases by 0.9 million acres, total cropland pasture decreases by 0.9 million acres, total forest pasture increases by 0.2 million acres, forestland decreases by 0.03 million acres. As soybean biodiesel increases (in the biodiesel scenario), total cropland increases by 1.2 million acres, cropland pasture decreases by 1.0 million acres, forest pasture increases by 0.2 million acres, and forestland decreases by 0.2 million acres. With an increase in switchgrass ethanol, cropland increases by 2.2 million acres, cropland pasture decreases by 1.5 million acres, forest pasture increases by 0.6 million acres, and forestland decreases by 0.6 million acres.

In the corn stover scenario, an increase in ethanol from corn stover does not directly result in crop acre changes, merely an increase in the harvesting of residue from existing corn acres. However, an increased demand for ethanol from corn stover does inherently give more value per acre of corn with residue removal. Based on corn residue removal possibilities by region, there are relatively small changes to land uses with an increase in corn stover ethanol production. Specifically, cropland increases by 0.07 million acres, cropland pasture increases by 0.05 million acres, forest pasture acres do not change, and forestland acres decrease by 0.2 million acres.

The number of acres enrolled in CRP does not vary between volume scenarios because in each scenario, the maximum amount is taken from the program and converted to cropland for production, all leaving the assumed minimum limit of 32 million acres, in accordance with the 2008 Farm Bill. The number of acres in rangeland does not vary because rangeland acres are not suitable for any other use than unmanaged land for livestock production. The only change in rangeland is whether or not a certain number of acres are actively used for production, or whether they remain idle. Lastly, developed land is assumed to be of higher value than all other land categories, and FASOM assumes that the amount of developed land increases at a steady rate over time, and does not vary with changes in demand for biofuel.

**Figure 2.4 15. Change in Domestic Land Use by Type, 2022**



Note: Some of these land use categories are not used in GHG emission calculations

### 2.4.4.1.3 Quantification of GHG Emissions from Domestic Land Conversions

Domestic land use change GHG emissions are based on outputs of the FASOM model. FASOM models the changes in GHG emissions and sequestration due to changes in land management. FASOM explicitly models change in soil carbon due to change in crop production acres and in crop type. In addition, FASOM's forestry module models the change in above-ground biomass and below-ground biomass carbon stock and soil carbon in the forestry sector due to land conversion. With the addition of the forestry module for the final rulemaking, we have used FASOM to model changes in soil carbon and biomass carbon due to land use conversion between cropland, pasture, forestland, and developed land.

In addition to quantifying GHG emissions and sinks, FASOM distinguishes the unique time dynamics and accounting issues of carbon sequestration options. These include issues such as saturation of carbon sequestration over time (i.e., carbon sequestration in a particular sink reaches an equilibrium such that carbon storage is maintained, but is no longer increasing), potential reversibility of carbon benefits (e.g., due to changes in tillage, forest harvests, wildfires), and fate of carbon stored in products after forest harvest.

GHGs, generally in the form of carbon, can be sequestered in soils, standing trees, other vegetation, and wood products. Sequestration refers to storage of the GHGs for more than one year. As a consequence, the sequestration definition used in the model for standing vegetation is limited to carbon storage in trees, understory, and litter within both forests and plantations of woody biofuel feedstocks (poplar and willow) but excludes, for instance, carbon stored in annually cultivated crops. Carbon sequestration is also modeled within cropland soils, pastureland soils, soils in idled lands, timberland soils, and harvested wood products. In addition, changes in sequestration for lands that move out of forestry and agricultural production into some form of developed usage such as housing, shopping centers, and roads are tracked in the model.

In the subsections below, we detail FASOM accounting of carbon stock changes from agricultural land and forestry land. We also describe EPA's use of FASOM GHG accounting to project the changes in GHG emissions associated with domestic land use change for each renewable fuel-specific pathways for the year 2022.

#### 2.4.4.1.4 Domestic Agricultural Soil GHG Accounting

FASOM models the change in agricultural soil carbon due to land conversion and changes in crop patterns. The FASOM GHG factors for agricultural land conversion are based on factors for different crops, management practices, and land conversion effects (e.g., converting pasture to crop production). As EPA committed in the NPRM, the FASOM agricultural land GHG emission factors were updated with new DAYCENT/CENTURY model runs to reflect the most recent science available.

Agricultural soil carbon sequestration depends on management activities that influence carbon storage per acre. Baseline carbon storage is estimated from the baseline distribution of land across tillage practices, irrigation status, land use, and cropping patterns, assuming carbon sequestration rates are equal to those at equilibrium.

Intensity of agricultural tillage. Agricultural soils have traditionally been tilled; however, tillage breaks up soil aggregates and increases the exposure of soil organic matter to oxygen, which speeds oxidation and results in reduced soil carbon with an associated release of CO2 into the atmosphere. The use of tillage alternatives that reduce soil disturbance and therefore reduce oxidation of soil organic matter will increase soil carbon sequestration. Reduced tillage practices also leave crop residues on the soil, thereby potentially increasing carbon inputs.

Irrigation status. The DAYCENT/CENTURY model shows differences in soil carbon sequestration per acre for a given region between irrigated and dryland cropland systems.[VVVVVV] For irrigated sites, the increased yields are expected to increase biological activity and therefore increase soil carbon sequestration compared to dryland cropland.

Relative abundance of grasslands. Generally, pastureland and CRP land experience less soil disturbance than actively tilled croplands and store more carbon per acre. Thus, changes in the distribution of land between pastureland, cropland, and land in the CRP will affect agricultural soil carbon sequestration.

Mix of annuals versus perennials. Perennial crops are not tilled on an annual basis typically show a reduction in soil disturbance relative to actively tilled annual crops. By definition in FASOM, perennial crops such as switchgrass, hybrid poplar, and willow are produced under zero tillage.

Changes in agricultural soil carbon due to changes in tillage, irrigation status, or land use are generally assumed to take place over a number of years as the soil carbon levels adjust to a new equilibrium. In FASOM, soil carbon levels are assumed to reach a new equilibrium after 25 years, although almost 94% of the adjustment takes place within 15 years (see Figure 2.4-16).[WWWWWW]

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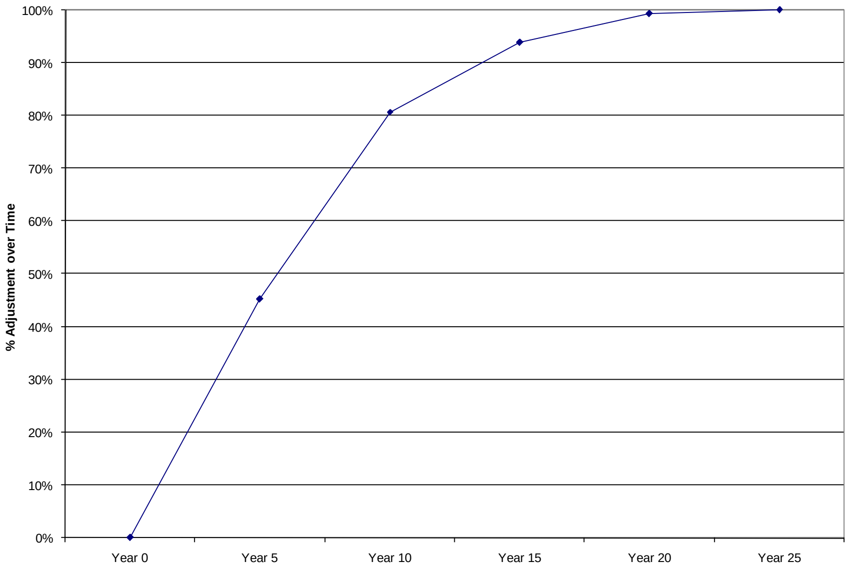
[VVVVVV] All pastureland and CRP land in FASOM are assumed to be produced in dryland systems.

[WWWWWW] There is an immediate jump in carbon storage in year 0 due to changing tillage, irrigation, and/or land use that depends on the initial state and the new state. The dynamics discussed and shown in Figure A-5 refer to the change over time from the initial state under new management /land use conditions to the equilibrium for that state.

**Figure 2.4-16.**
**Percentage Adjustment over Time to New Soil Carbon Equilibrium Following Change in Land Use or Management**



Because movement of soil carbon sequestration towards equilibrium levels is not constant over time, FASOM yields non-uniform changes in soil carbon consistent with the generally accepted scientific finding that carbon sequestered in an ecosystem approaches steady-state equilibrium under any management alternative. The rate of change in carbon storage decreases over time and eventually reaches zero at the new equilibrium (saturation). See Figure 2.4-16.[534] Soil carbon per acre may increase or decrease depending on the land use change or change in land management taking place.

FASOM also estimates N2O emissions from cropland and pastureland due to land use change based on Colorado State University DAYCENT/CENTURY models. See Section 2.4.2.2 for a full discussion.

2.4.4.1.5 Evaluation of GHG Emissions Impacts from Domestic Forests

One of the largest carbon pools is carbon sequestered in forests. Carbon is stored not just in the live and standing dead trees, but also in understory, forest floor and coarse woody debris, and forest soil. Harvesting timber causes a reduction in carbon sequestration, although some of the carbon that was in the harvested trees will continue to be stored in forest products for some time afterward. If harvested stands are replanted, then there is little loss in forest soil carbon, and carbon sequestration in trees planted in that stand will increase over time.

The FASOM model estimates change in carbon stock of above-ground and below-ground biomass in continuous and afforesting forestland. It accounts for carbon storage in forest products and emission streams from these products over time. It also takes into account changing management practices (e.g., harvest cycles). Land converted from forestry to agricultural or other uses, however, will have a much greater permanent reduction in carbon sequestration. We summarize the forest carbon accounting procedures used in FASOM below.[535]

Forest carbon accounting in FASOM follows the FORCARB model developed by the U.S. Forest Service and used in the periodic aggregate assessments of forest carbon sequestration. Tree carbon is the largest forest carbon pool and is modeled as a function of three factors: (1) merchantable volume, (2) the ratio of growing stock volume to merchantable volume, and (3) and parameters of a forest volume-to-biomass model developed by U.S. Forest Service researchers.[536] Harvest age is allowed to vary; thus, the growth of existing and regenerated/afforested stands must be modeled. Timber growth and yield data are included for existing stands, reforested stands, and afforested lands that track the volume of wood in each unharvested stand, which, in turn, is used in computing forest carbon sequestration. These data indicate the wood volume per acre in unharvested timber stands for each timber stand strata (e.g., a stand giving location, forest type, management intensity class) by age cohort. The data used are derived largely from the U.S. Forest Service RPA modeling system.[537] Merchantable volume, by age, on each representative stand is obtained from the timber growth and yield tables included in FASOM. The volume factors and biomass model parameters vary by species and region and are obtained from[538, 539] and Smith et al. (2003).[540]

Carbon in live and standing dead trees is calculated using the parameters of the forest volume-to-biomass model equations for live and dead tree mass densities (above- and belowground) in Smith et al.,[541] weighted for the FASOM region/forest type designations. Forest land area data reported by the RPA assessment[542] are used to calculate the appropriate weights. Birdsey's assumption that the mass of wood is approximately 50% carbon is used to derive the associated levels of carbon.[543]

Soil carbon is the second-largest pool of carbon. Treatment of soil carbon follows Birdsey[544,545] and recent work by Heath, Birdsey, and Williams.[546] FASOM computes soil carbon profiles using soil carbon data over time from Birdsey.[547,548] As Heath, Birdsey, and Williams noted, little change in soil carbon occurs if forests are regenerated immediately after harvest.[549] As a result, FASOM assumes soil carbon on a reforested stand remains at a steady-state value. Currently, the age that this value is reached is assumed to be the minimum harvest age for FASOM region/forest type. This assumption is generally consistent with the ages at which steady-state levels of soil carbon are achieved in Birdsey.[550,551] Afforested land coming from crop or pasture use start with the initial soil carbon value for that land/region combination reported by the Century Model, which was developed by Colorado State University.[XXXXXX] The land then accumulates carbon until reaching the steady-state value for forests of the type planted

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[xxxxxx] The current version of the CENTURY agroecosystem model simulates carbon, nitrogen, phosphorous, and sulfur dynamics through an annual cycle over time scales and centuries and millennia. CENTURY is capable of modeling a wide range of cropping system rotations and tillage practices for analysis of the effects of management and climate on agroecosystem productivity and sustainability. The model has undergone numerous enhancements since the original version developed in Parton, W.J., D.S. Schimel, C.V. Cole, and D.S. Ojima. 1987. Analysis of factors controlling soil organic matter levels in Great Plains grasslands. Soil Science Society of America Journal 51:1173-1179.

in the region afforestation takes place (where steady state is assumed to be reached at the minimum harvest age in FASOM for that region/forest type).

Forest floor carbon constitutes the third largest carbon storage pool, but is much smaller than tree or soil carbon pools. FASOM bases its forest floor carbon estimates on the model developed by Smith and Heath[552] to estimate forest floor carbon mass. The model's definition of forest floor excludes coarse woody debris materials; that is, pieces of down dead wood with a diameter of at least 7.5 cm that are not attached to trees.[553] In order to account for this material, coarse woody debris is assumed to be a fixed fraction of live tree carbon based on ratios of coarse woody debris carbon to live tree carbon.[554] This value is then added to the forest floor carbon values generated by Smith and Heath's forest floor model. The model for net accumulation of forest floor carbon is a continuous and increasing function of age, although the rate of accumulation eventually approaches zero (i.e., forest floor carbon reaches a steady state).

Understory vegetation comprises the smallest component of total carbon stock and includes all live vegetation except trees larger than seedlings. FASOM makes the assumption that understory carbon is a fixed fraction of live tree carbon and uses published ratios reported in U.S. EPA Inventory of U.S. GHG Emissions and Sinks[555] as the basis for these calculations. When timber is harvested, FASOM tracks the fate of the carbon that had been sequestered on the harvested land.

Figure 2.4-17 summarizes the disposition of carbon following harvest. To calculate carbon in harvested logs, cubic feet of roundwood (the units in which timber is quantified in the model) is converted into metric tons of carbon using factors reported in Skog and Nicholson.[556] These factors vary by region and are reported for logs coming from an aggregate softwood and hardwood stand. They exclude carbon in logging residue left onsite. Logging residue is tracked separately in the forest floor carbon pool described above.

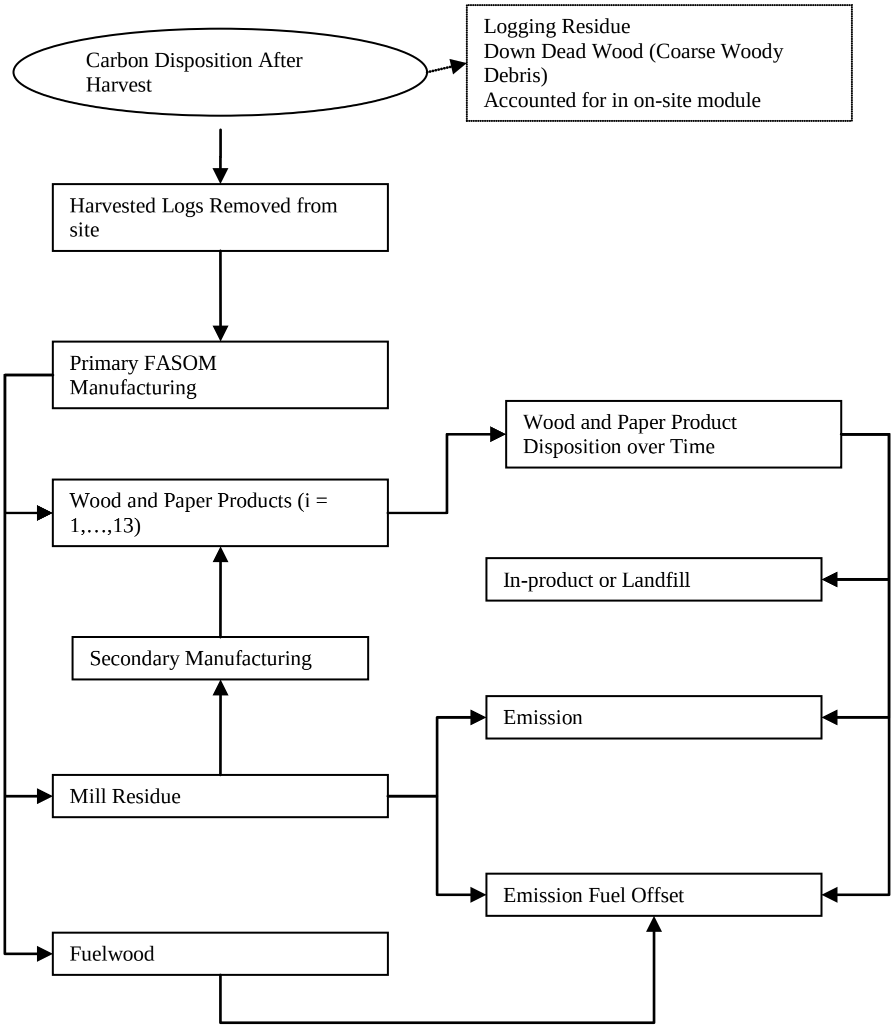
Harvested logs removed from site are converted into three types of outputs through primary manufacturing processes: wood and paper products, mill residues, and fuel wood. See Table 2.4-27 for a list of products tracked by FASOM. The fate of each of these outputs is discussed below.

**Table 2.4-27. Wood and paper products tracked by FASOM**

| Product |
|---|
| softwood sawlogs for export |
| hardwood sawlogs for export |
| softwood lumber |
| softwood plywood |
| oriented strand board |
| hardwood lumber |
| hardwood plywood |
| softwood miscellaneous products |
| hardwood miscellaneous products |
| softwood used in non-OSB reconstituted panel |
| hardwood used in non-OSB reconstituted panel |
| softwood pulpwood |
| hardwood pulpwood |

The distribution of product carbon changes over time. FASOM tracks the fate of product carbon with two carbon pools: carbon remaining in-product and carbon leaving the product (Figure 2.4-17). Carbon that leaves the product ultimately is emitted or permanently sequestered in landfills.

Figure 2.4-17. Carbon Disposition after Timber Harvest[557]

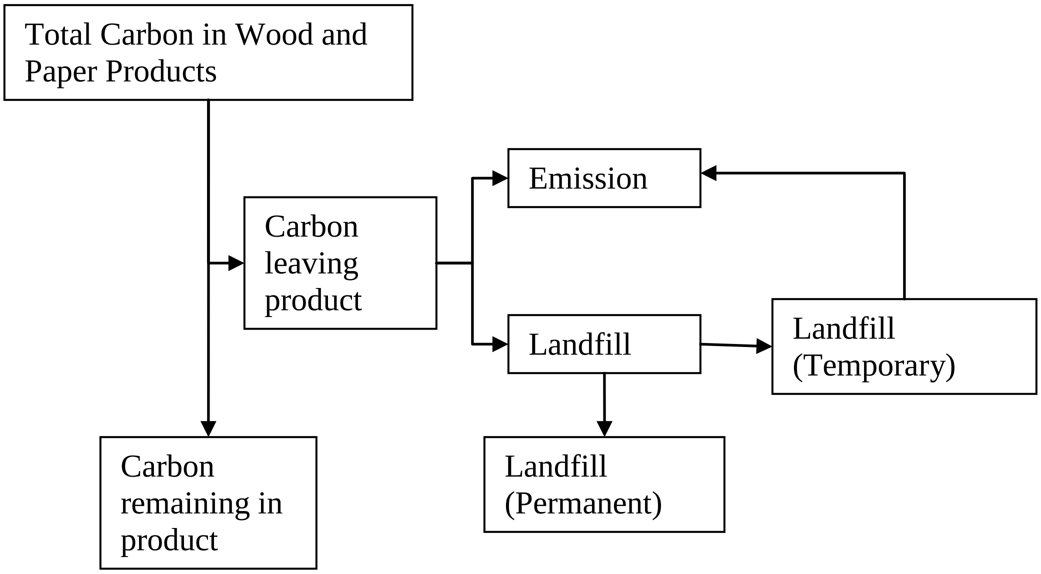


FASOM determines the fraction of carbon that remains in products using specified half-life values for a set of end-use categories (Table 2.4-28).[558] The half-life represents the time it takes for approximately half of the product to decompose. Skog and Nicholson[559] assumed that 67% of carbon leaving the wood product pool and 34% of carbon leaving the paper product pool goes to landfills (Figure 2.4-18). The remainder of the carbon leaving the wood and paper product pools is emitted as CO2 into the atmosphere.

### Table 2.4-28. Half-life for Forest Products in End Uses[560]

| End Use or Product | Half-Life in Years |
|---|---|
| Paper | 2 |
| New residential construction | |
| Single family | 100 |
| Multifamily | 70 |
| Mobile homes | 12 |
| Residential upkeep & improvement | 30 |
| New nonresidential construction | |
| All ex. railroads | 67 |
| Railroad ties | 12 |
| Railcar repair | 12 |
| Manufacturing | |
| Household furniture | 30 |
| Commercial furniture | 30 |
| Other products | 12 |
| Shipping | |
| Wooden containers | 6 |
| Pallets | 6 |
| Dunnage etc. | 6 |
| Other uses for lumber and panels | 12 |
| Uses for other industrial timber products | 12 |
| Exports | 12 |

**Figure 2.4-18. Wood and Paper Product Carbon Disposition**[561]



FASOM tracks the fate of mill residue using two different pools. The first is for mill residue that is used as an intermediate input in the production of wood and paper products. This carbon is tracked using the appropriate product category as described above. The second pool is for carbon in mill residue that is burned for fuel. The fraction burned in each region based on Smith et al.[562] It was assumed that one-third of mill residue burned is used to offset fossil fuels. Harvested fuel logs and the associated carbon are used as to produce energy at mills. For fuel wood, FASOM assumes that 100% of fuel wood burned in the sawtimber and pulpwood production process is used to offset fossil fuels.

In FASOM, land used in forestry can move to agriculture or developed use, resulting in a dynamic change in carbon storage levels on the previously forested land. When land moves from forestry to agricultural use or developed use, FASOM tracks carbon in residual forest floor carbon and in soil carbon. FASOM's model of forest floor decay is based on the average forest floor of mature forests and regional averages for decay rates, as described in Smith and Heath.[563] When forested land is converted to agricultural use, soil carbon levels are consistent with DAYCENT/CENTRUY model data on agricultural soil carbon for the appropriate category of agricultural land and do not vary over time. When forest is converted to developed land uses, FASOM assumes that soil carbon levels are consistent with the steady-state value of the minimum harvest age.

#### 2.4.4.1.6 Aggregate GHG Emissions Impacts from Domestic Land Conversions in 2022

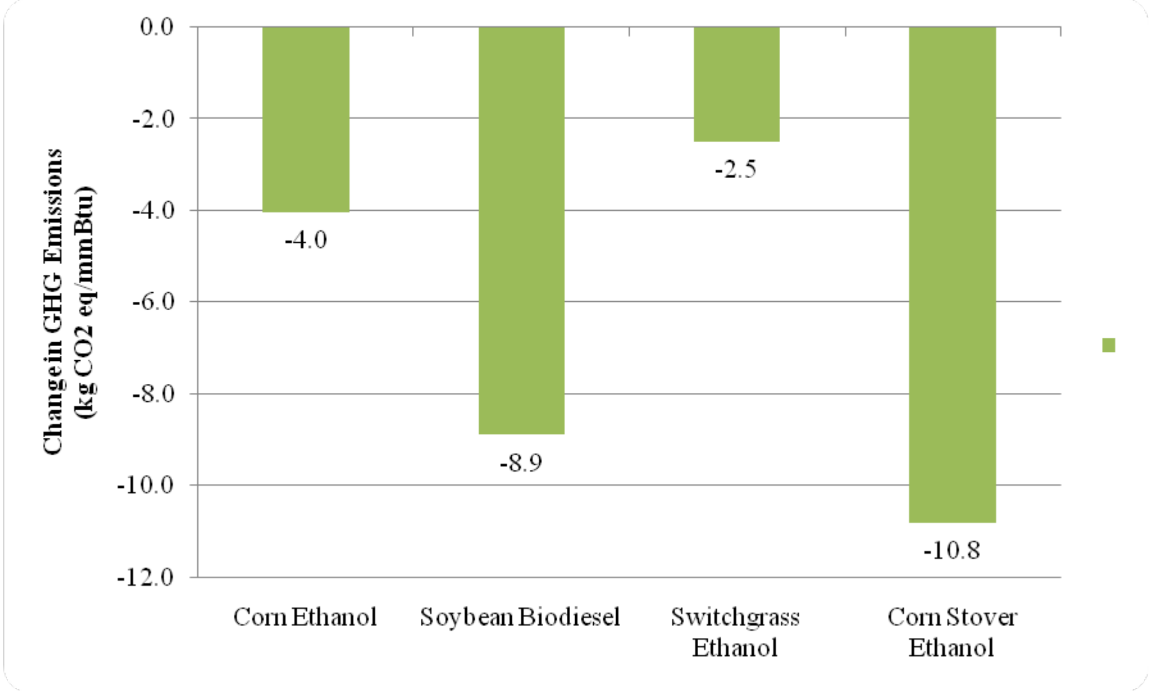
In the FASOM model the difference in GHG emissions and sequestrations from agricultural and forest lands related to land use changes are not only a function of the difference between the land use change and management practices in 2022 under two scenarios, but are also dependent on previous changes in land use and practices under the two scenarios. For instance, different land use patterns under two scenarios may result in differing harvesting cycles.

Ideally, an emissions comparison of land use patterns in two scenarios would capture the changes and associated emissions that lead to the 2022 land use status in both scenarios. Because FASOM generates GHG emissions estimates associated with land use change for every five year period over the time horizon of the model run, EPA was able to calculate the cumulative GHG emissions change for each fuel-specific pathway and for the RFS2 policy. We then annualized the cumulative change.

To calculate the annualized cumulative GHG emissions due to land use change for a specific fuel, we first summed all emissions associated with agricultural land (CO2 and N2O from cropland, pastureland, CRP land) and forestland (CO2 from biomass, soil, and forest products) between the years 2000 and 2022 for the control and fuel-specific scenarios. Emissions from soil, decaying biomass, and forest products can occur over several years or decades. FASOM tracks such emission streams over time. We included in the cumulative GHG emissions from land use change all emission streams due to changes that occurred between 2000 and 2022 for the thirty year time horizon (See Section 2.4.5) after 2022.

We report these results as CO2 equivalent mass and then normalize the results on an mmBtu basis (Figure 2.4-19).

**Figure 2.4-19. Change in GHG Emissions Due to Domestic Land Use Change by Scenario, 2022, Annualized Over 30 Years**



## 2.4.4.2 International Land Conversion GHG Emissions Impacts

### 2.4.4.2.1 Area and Location of International Land Conversions

We used the FAPRI-CARD international agricultural models to determine the amount of international land use change resulting from the renewable fuel volumes mandated by RFS2. The FAPRI-CARD model provides a dynamic projection of how policy or economic shocks will affect international agricultural commodity markets, and the resulting area of land used to produce agricultural goods. FAPRI-CARD accounts for several key factors that affect the amount/area of international land use change: crop yield growth rates over time, price-induced crop yield changes, crop yields on marginal/new land, the efficiency of renewable fuel co-products over time, supply and demand in the livestock sector, and many other significant variables. More details about the FAPRI-CARD model and our assumptions are provided in RIA Chapter 5.

### 2.4.4.2.2 Area and Location of International Cropland Conversions

To determine the area of land use change caused by increased consumption of each of the renewable fuels analyzed (i.e., corn ethanol, soy-based biodiesel, sugarcane ethanol and switchgrass ethanol) we used the FAPRI-CARD model to simulate the scenarios outlined in

Table 2.3-1. By varying only one type of renewable fuel in each scenario we isolated the impacts for each fuel type. The land use change results are the difference between each scenario and the control case, and are normalized by dividing by the incremental increase in renewable fuel production in a given scenario and year, on an energy-content basis. Table 2.4-29 shows foreign (i.e. not including the United States) crop area changes in thousands of harvested hectares (000s ha), and the normalized changes in hectares per billion British Thermal Units (ha/ billion BTU), for each of the scenarios considered.[YYYYYY] Note that we focus on the change in land use between scenarios in 2022.[ZZZZZZ]

**Table 2.4-29. Changes in International Crop Area Harvested, by Renewable Fuel, 2022**

| Scenario | International Crop Area Change (000s ha) | Normalized Crop Area Change (ha/billion BTU) |
|---|---|---|
| Corn Ethanol | 789 | 3.94 |
| Soy-Based Biodiesel | 678 | 10.65 |
| Sugarcane Ethanol | 430 | 4.38 |
| Switchgrass Ethanol | 1358 | 2.25 |

The location of land use changes is a critical factor in the determination of land use change GHG impacts, because the GHG impacts of land conversions varies substantially by region. For example, deforestation in the tropics releases substantially more carbon than deforestation in drier regions. The FAPRI-CARD model allocates crop area changes across 54 regions based on a number of factors, including existing trade patterns, regional costs of production, and the potential for agricultural expansion in each region. Normalized crop area changes by region and renewable fuel are shown in Figure 2.4-20, with 12 aggregated regions for purposes of illustration. Once again, land use changes in the United States are excluded from the figure, except for the case of sugarcane ethanol.

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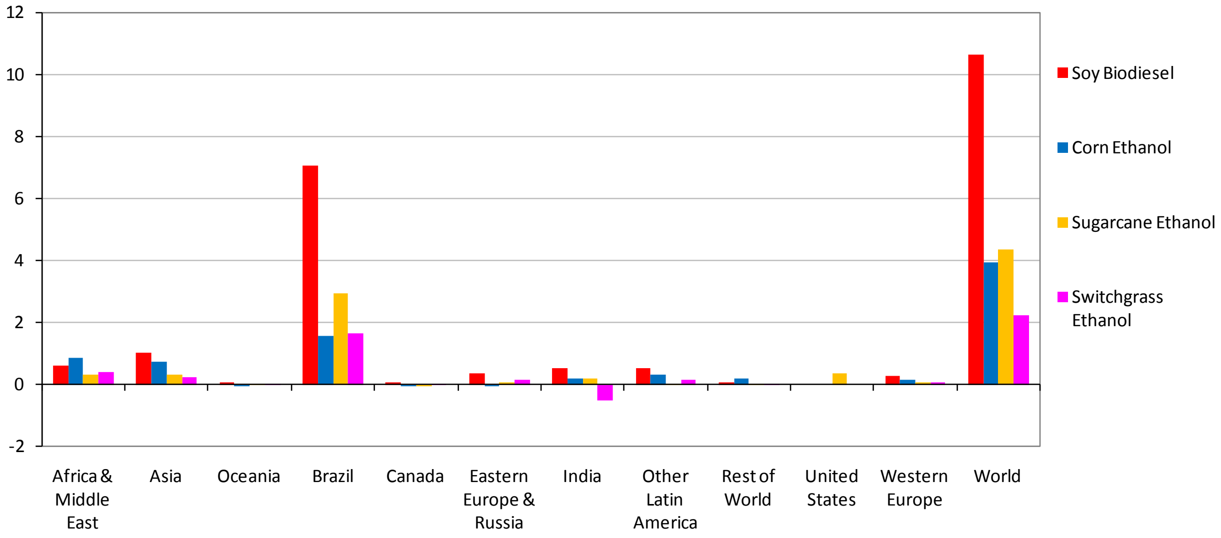
[YYYYYY] The sugarcane ethanol scenario includes land use changes in the United States as projected by FAPRI-CARD. For all of the other renewable fuels, domestic land use changes were determined with FASOM as described in the previous section.

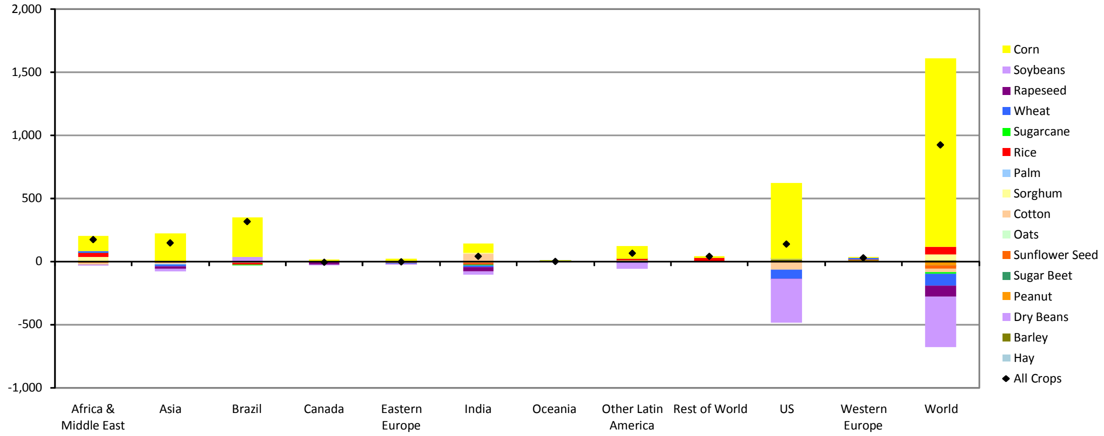
[ZZZZZZ] We assumed 76,000 BTU/gallon of ethanol; 115,000 BTU/gallon of biodiesel and 2.471 acres/hectare.

### Figure 2.4 20. Normalized Harvested Crop Area Changes by Renewable Fuel, 2022 (ha /billion BTU)

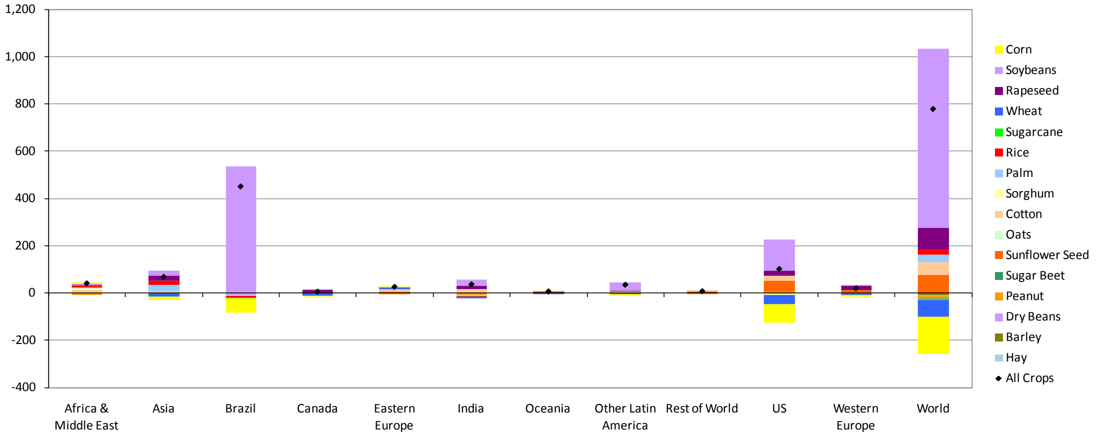


The projected net changes in crop area are the result of many factors, including shifting among different types of crops in each region. For example, for scenarios where corn ethanol production increases in the United States, we project a domestic shift from soybean production to corn production, and a shift toward oilseeds production in other countries to fill the gap in lost U.S. output. The following figures illustrate projected changes in harvested area by crop type and region for each renewable fuel scenario. All results are from the FAPRI-CARD model, with changes in the United States are included for illustrative purposes.

### Figure 2.4-21. Harvested Crop Area Changes by Crop and Region Corn Ethanol Scenario, 2022 (000s ha)



## Figure 2.4-22. Harvested Crop Area Changes by Crop and Region Soy-Based Biodiesel Scenario, 2022 (000s ha)



## Figure 2.4-23. Harvested Crop Area Changes by Crop and Region Sugarcane Ethanol Scenario, 2022 (000s ha)

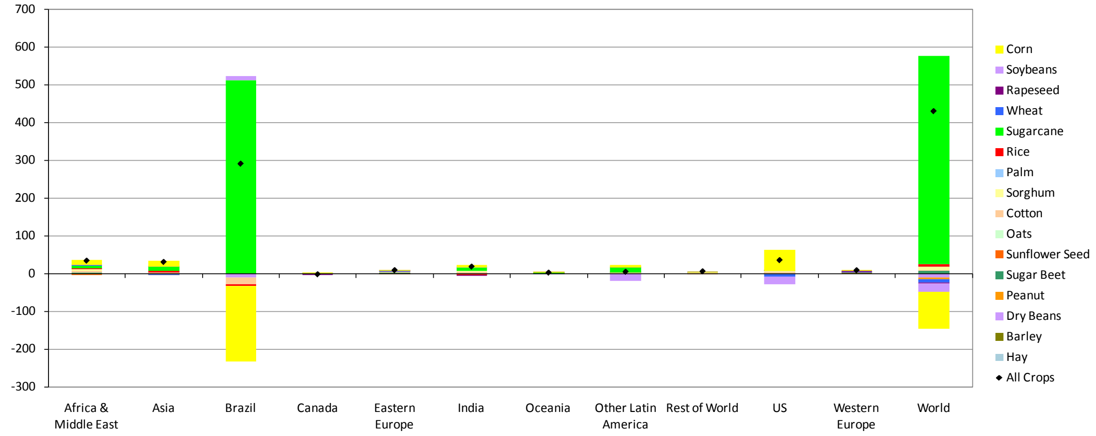
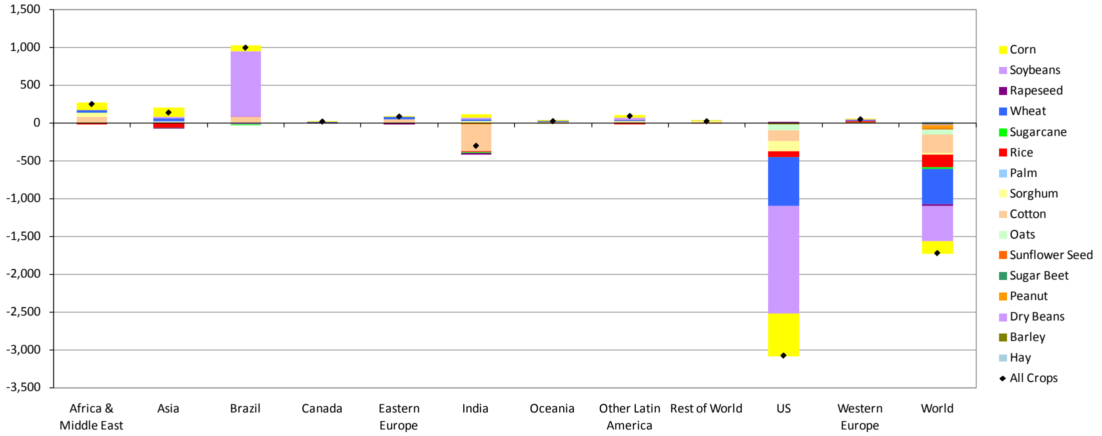


**Figure 2.4-24. Harvested Crop Area Changes by Crop and Region Switchgrass Ethanol Scenario, 2022 (000s ha)**



Note: Switchgrass harvested area is not included in the figure.

### 2.4.4.2.3 Area and Location of International Pasture Land Conversions

In addition to considering international changes in crop area, our analysis also accounts for changes in pasture area, i.e., land used for livestock grazing. Accounting for pasture area is essential to understand the land use change impacts of renewable fuels, because renewable fuel production can affect the livestock sector which uses pasture. Furthermore, more land is used globally for pasture than for crop production.[564] The new, more detailed, representation of Brazil in the FAPRI-CARD model (see RIA Chapter 5 for more details) explicitly accounts for changes in pasture area, therefore, accounting for the competition between crop and pasture land uses. Furthermore, the FAPRI-CARD Brazil module allows for livestock intensification, i.e., the increasing the heads of cattle per unit area of land in response to higher commodity prices, increased demand for land, or other reasons. In addition to modifying how pasture is treated in Brazil, we also improved the methodology for calculating pasture area changes in other countries.

In the proposed rule, we made a broad assumption that the total land area used for pasture would stay constant in each country or region. Thus, in the proposed rule, we assumed that any crop expansion onto pasture would necessarily require an equal amount of pasture to be replaced on forest or shrubland. For the final rule we relaxed this assumption, and we now account for changes in pasture area resulting from livestock fluctuations and therefore capture the link between livestock and land used for grazing. Based on regional pasture stocking rates (i.e., livestock per hectare), we now calculate the amount of land used for livestock grazing. As a result of this analytical improvement, in countries where we project decreased livestock numbers we also project less land needed for pasture. Therefore, unneeded pasture areas are available for cropland or allowed to revert to their natural state. In countries where livestock numbers increase, more land is needed for pasture, which can be added on abandoned cropland or unused grassland, or it can result in deforestation. This new methodology provides a more realistic assessment of land use changes, especially in regions where livestock populations are changing significantly.

A multi-step process was used to translate the FAPRI-CARD livestock projections to pasture area changes. First, the FAPRI-CARD projections for dairy cattle and beef cattle (i.e., all non-dairy cattle) and sheep were converted to animal unit equivalents (AUE) using IPCC data (see Table 2.4-30).[565] Next, average stocking rates for each of the 54 FAPRI-CARD regions were determined with data on livestock populations from the UN Food and Agricultural Organization (FAO)[566] and data on pasture area measured with agricultural inventory and satellite-derived land cover data.[567] The FAO data set provides a globally consistent estimate of livestock units per country. The estimated stocking rates are listed in Table 2.4-31. Expert judgment was used to adjust unusually low regional stocking rates. For example, we removed serious outliers from the "CIS, Other" FAPRI-CARD region.[AAAAAAA] Specifically Kazakhstan and Turkmenistan were removed from this calculation because these countries include vast stretches of desert pasture used for rotational sheep grazing. Removing these outliers provided a more realistic estimate of how cattle population changes would affect land use in this region. For other regions that had unreasonably low stocking rate factors, we set the stocking rates equal to a neighboring country with a more reasonable factor.[BBBBBBB]

Based on the data sources considered, some regions had very high stocking rates due in part to the use of intensive livestock operations, such as feedlots. We did not adjust these stocking rates because we would not expect livestock population changes to have a large impact on pasture area in these regions.

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[AAAAAAA] CIS, Other includes the following countries in the Commonwealth of Independent States: Armenia, Azerbajian, Belarus, Georgia, Kazakhstanm, Krygyzstan, Moldova, Tajikistan, Turkmenistan, Uzbekistan

[BBBBBBB] These adjustments were made after consulting experts at Iowa State University and USDA who suggested that, although the best available data was used, the calculated stocking rates in many regions were unreasonably low. One reason for this, and part of the justification for adjusting the stocking rates upward, is that the data used considered all pasture land globally, including areas (e.g., Kazakhstan) with extraordinarily low stocking rates. The adjustments help to account for the fact that we would expect biofuel-induced livestock changes to affect globally integrated livestock regions, and these regions would likely not exhibit very low stocking rates.

**Table 2.4-30. Animal Unit Equivalents (Livestock Units per Head)**

| Region | Dairy | Beef | Sheep |
|---|---|---|---|
| Canada | 1.33 | 0.86 | 0.18 |
| Western Europe | 1.32 | 0.93 | 0.18 |
| Eastern Europe | 1.21 | 0.86 | 0.18 |
| Oceania | 1.10 | 0.73 | 0.10 |
| Brazil | 0.88 | 0.67 | 0.10 |
| Other Latin America | 0.88 | 0.67 | 0.10 |
| Asia | 0.77 | 0.70 | 0.10 |
| Africa & Middle East | 0.61 | 0.38 | 0.10 |
| India | 0.61 | 0.24 | 0.10 |
| US | 1.33 | 0.86 | 0.18 |
| Rest of World | 1.00 | 0.69 | 0.13 |

Source: IPCC Vol. 4, Ch.10

**Table 2.4-31. Pasture Stocking Rates by FAPRI-CARD Region (Livestock Units /Ha)**

| FAPRI-CARD Regions | Stocking Rate | Notes/Adjustments |
|---|---|---|
| Algeria | 0.50 | equals Tunisia |
| Argentina | 0.41 | |
| Australia | 0.41 | equals world average |
| Bangladesh | 25.25 | |
| Brazil: Amazon Biome | 0.95 | from FAPRI-CARD Control Case, 2022 |
| Brazil: Central-West Cerrados | 1.00 | |
| Brazil: Northeast Coast | 0.87 | |
| Brazil: North-Northeast Cerrados | 0.90 | |
| Brazil: South | 1.62 | |
| Brazil: Southeast | 0.94 | |
| Canada | 0.64 | |
| China | 0.41 | |
| New Zealand | 1.14 | |
| Colombia | 0.60 | |
| Cuba | 1.02 | |
| Egypt | 0.44 | equals Iraq |
| EU | 1.45 | |
| Guatemala | 0.74 | |
| India | 9.22 | |
| Indonesia | 4.11 | |
| Iran | 0.22 | |
| Iraq | 0.44 | |
| Ivory Coast | 0.45 | equals Guinea |
| Japan | 9.63 | |
| Malaysia | 1.99 | |
| Mexico | 0.45 | |
| Morocco | 0.50 | equals Tunisia |
| Myanmar (Burma) | 11.41 | |
| Nigeria | 0.74 | |
| Africa, Other | 0.33 | Zambia, Chad and Botswana removed |
| Asia, Other | 0.34 | Mongolia & Singapore removed |

|  |  |  |
|---|---|---|
| CIS, Other | 0.45 | Kazakhstan & Turkmenistan removed |
| Eastern Europe, Other | 0.37 |  |
| Latin America, Other | 0.52 | Bolivia removed |
| Middle East, Other | 0.30 |  |
| Pakistan | 3.64 |  |
| Paraguay | 0.35 |  |
| Peru | 0.37 |  |
| Philippines | 17.16 |  |
| Rest of World | 0.41 | equals world average |
| Russia | 0.41 | equals China |
| South Africa | 0.33 | equals Africa, Other |
| South Korea | 35.14 |  |
| Taiwan | 0.41 | equals China |
| Thailand | 17.01 |  |
| Tunisia | 0.50 |  |
| Turkey | 0.61 |  |
| Ukraine | 0.49 |  |
| Uruguay | 0.67 |  |
| United States | 0.46 |  |
| Uzbekistan | 0.45 | equals CIS, Other |
| Venezuela | 0.63 |  |
| Vietnam | 8.95 |  |
| Western Africa | 1.89 |  |
| World | 0.41 |  |

As described above, pasture intensification was modeled endogenously in Brazil by the FAPRI-CARD model. In the FAPRI-CARD model, pasture intensification was a function of many factors, including livestock and crop prices, and competition for land between grazing and crop production uses. In general, the FAPRI-CARD results produced pasture intensification elasticities of 5-10% (i.e., the % change in pasture intensification resulting from a % change in livestock population). For regions outside of Brazil we used a simple pasture intensification factor of 10% in regions where livestock populations increased.

Table 2.4-32 shows total and normalized international pasture area changes for each of the scenarios considered.[CCCCCCC] The pasture area results are largely driven by the relative changes in the livestock markets. In scenarios where beef and dairy production (which require pasture) declined more than swine and poultry production (which do not require pasture), the pasture area changes were larger. Section 2.4.3.6 includes international livestock production results for each scenario, and RIA Chapter 5 discusses the determining factors for these changes, such as co-product and livestock feed ration efficiencies.

**Table 2.4 32. Changes in International Pasture Area by Renewable Fuel, 2022**

| Scenario | International Pasture Area Change (000s ha) | Normalized Pasture Area Change (ha / billion BTU) |
|---|---:|---:|
| Corn Ethanol | -446 | -2.23 |
| Soy-Based Biodiesel | -268 | -4.20 |
| Sugarcane Ethanol | -164 | -1.67 |
| Switchgrass Ethanol | -580 | -0.96 |

Note: Only the Sugarcane ethanol scenario results include United States land use changes.

The location of pasture area changes is very important when analyzing these results. As the above table shows, we projected that global pasture area would decrease in all of our renewable fuel scenarios. However, pasture area changes resulted in positive net GHG emissions in some cases because of the location of the resulting land conversions. For example, in the corn ethanol scenario we projected a significant increase in pasture area in the Brazilian Amazon, which causes large GHG emissions. Figure 2.4-25 illustrates pasture area changes by region. Figure 2.4-26 includes pasture area changes by region in Brazil.

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[CCCCCCC] The sugarcane ethanol scenario includes land use changes in the United States as projected by FAPRI-CARD. For all of the other renewable fuels, domestic land use changes were determined with FASOM as described in the previous section. Thus, in Table 2.4-32 only the sugarcane ethanol scenario includes United States land use change results.

Figure 2.4-25. Normalized Pasture Area Changes by Renewable Fuel, 2022
(ha / billion BTU)

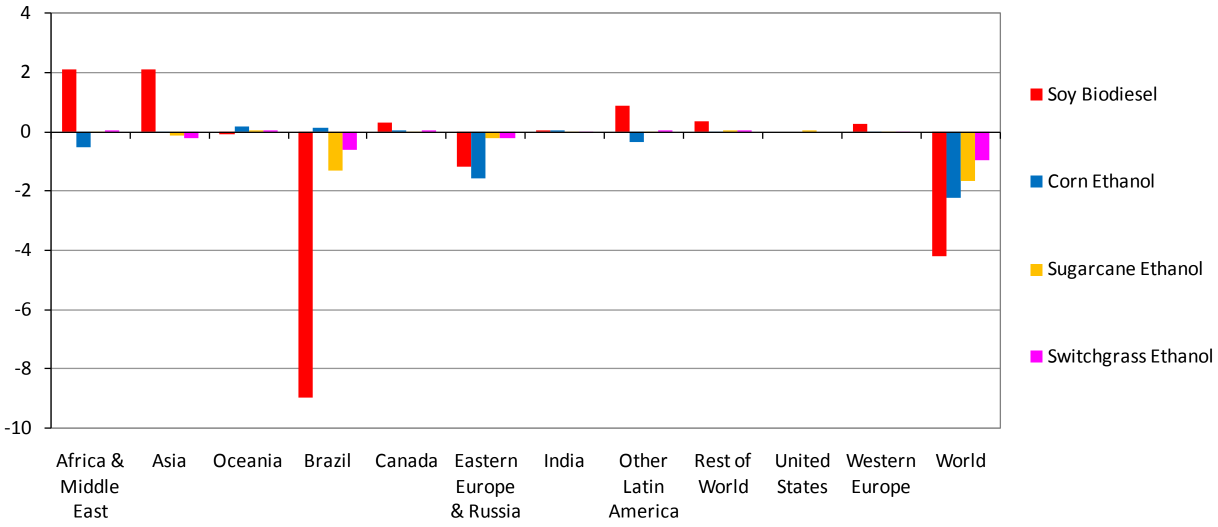
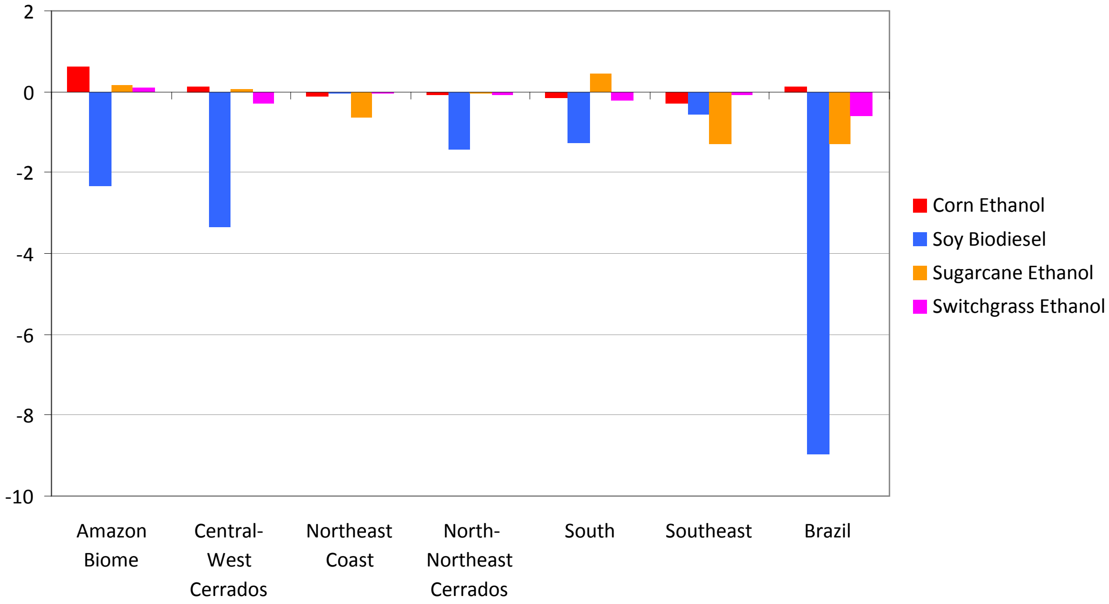


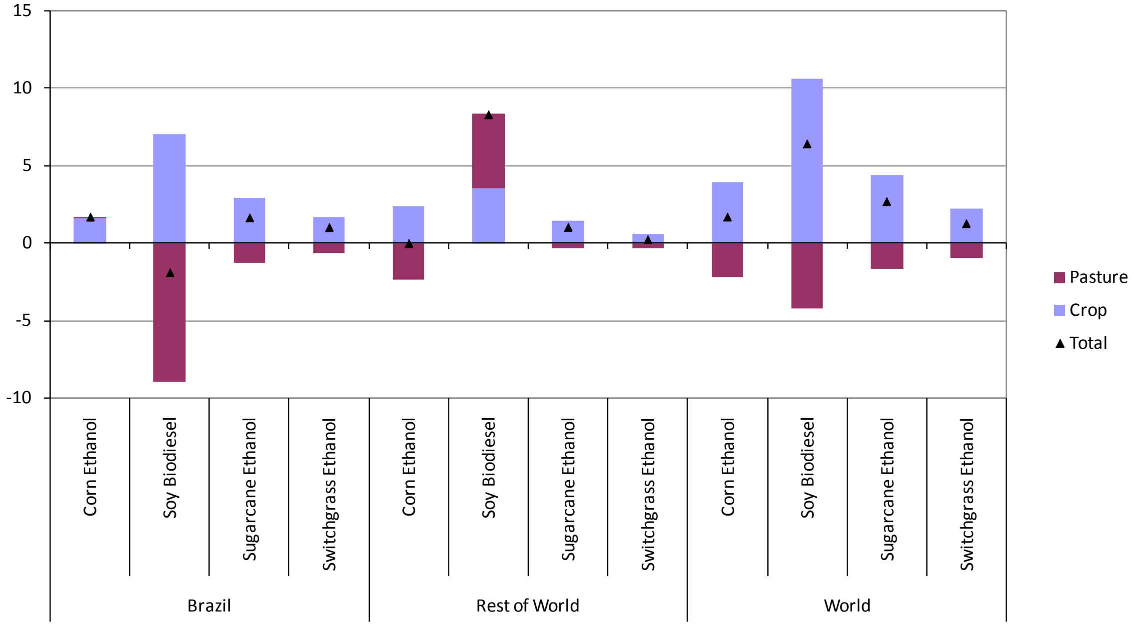
Figure 2.4-26. Normalized Pasture Area Changes in Brazil by Renewable Fuel, 2022
(ha / billion BTU)



### 2.4.4.2.4 Area and Location of International Cropland and Pasture Land Conversions

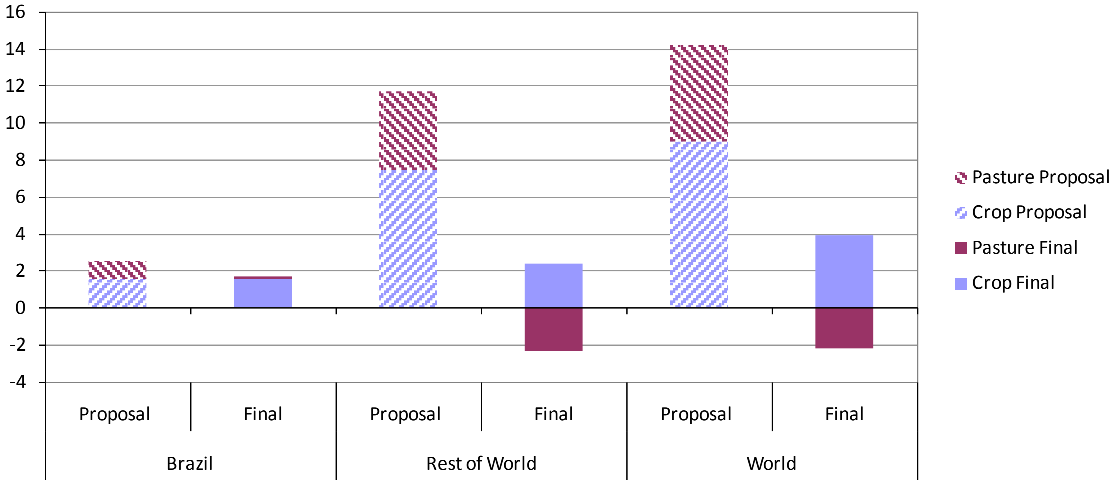
As discussed above, in the proposed rule we made a broad assumption that the total land area used for pasture would stay constant in each country or region. Thus, in the proposed rule, we assumed pasture area could not decrease in regions where crop area increased. In the final rule analysis we used a more sophisticated approach that captures a wider range of potential interactions between crop and pasture areas. For example, in regions were pasture decreases, this land is available for crop expansion. Therefore, it is important to look at both the crop and pasture area changes together to understand the land use change GHG emissions impacts. Figure 2.4-27 shows the crop and pasture area changes for each scenario. Brazil is broken out as a separate region because, as the figure shows, it is the most important country in terms of its response in livestock production and pasture area.

**Figure 2.4 27. Normalized International Land Use Change by Renewable Fuel (ha / billion BTU)**

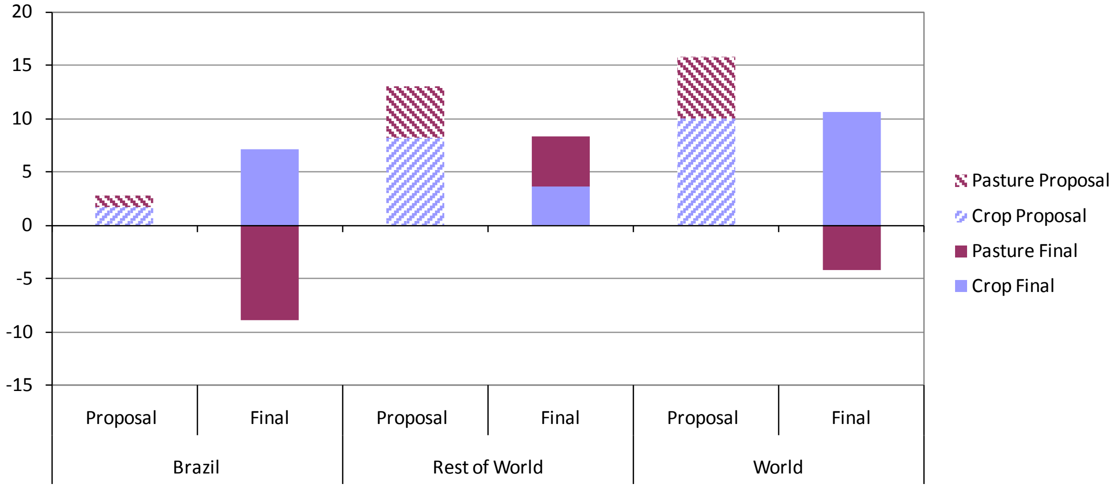


Finally, the following figures compare the proposed rule land use change projections to the land use change results in the final rule. Notice that in the final rule pasture area decreases in many regions, whereas in the proposed rule we assumed that pasture area could not decline. As discussed in the next sections, this had a large impact on the types of land conversions projected, and on the resulting GHG emissions impacts.

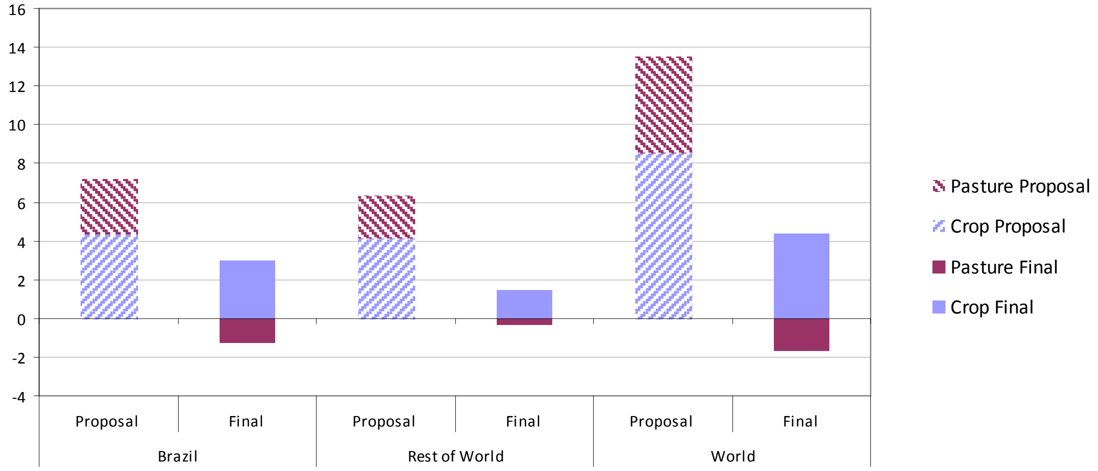
## Figure 2.4-28. Proposed Rule and Final Rule Comparison Normalized International Land Use Changes Corn Ethanol, 2022 (ha / billion BTU)



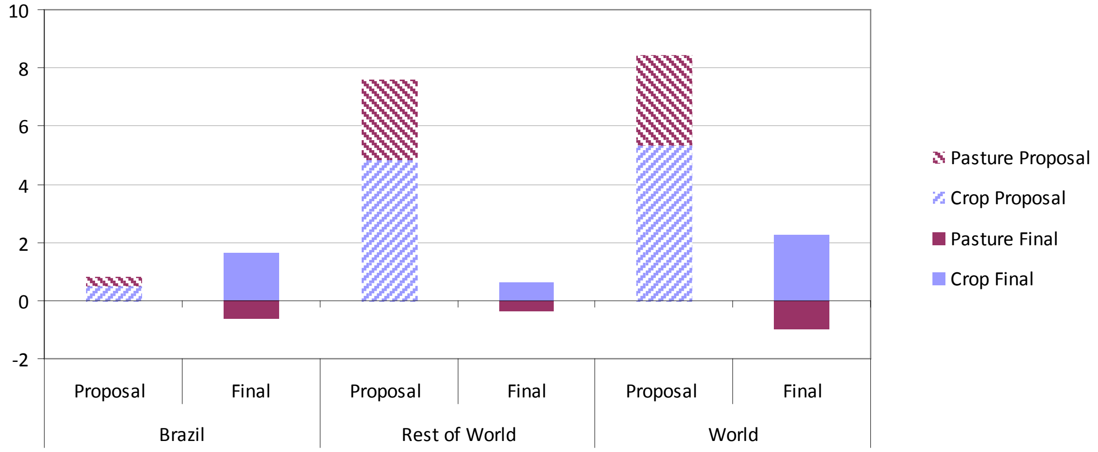
## Figure 2.4-29. Proposed Rule and Final Rule Comparison Normalized International Land Use Changes Soy-Based Biodiesel, 2022 (ha / billion BTU)



## Figure 2.4-30. Proposed Rule and Final Rule Comparison Normalized International Land Use Changes Sugarcane Ethanol, 2022 (ha / billion BTU)



## Figure 2.4-31. Proposed Rule and Final Rule Comparison Normalized International Land Use Changes Switchgrass Ethanol, 2022 (ha / billion BTU)



### 2.4.4.2.5 Evaluation of the Types of International Land Conversions

As explained in the previous section, the FAPRI-CARD international models were used to project changes in the area of land used for cropland and pasture in 54 regions. In this section we describe the two-step procedure that was used to determine in more detail the types and locations of land conversions:

1. The FAPRI-CARD output was disaggregated into 12 land conversion categories.
2. The land cover types affected (e.g., forest or grassland) and the location of land conversions (i.e., by Administrative Unit) were evaluated with MODIS Version 5 satellite data from 2001-2007.

#### 2.4.4.2.5.1 Determination of International Land Conversion Categories

Based on the FAPRI-CARD model results, we determined the conversions between annual crops, perennial crops, pasture land, and natural ecosystems in each of the 54 FAPRI-CARD regions. First, the FAPRI-CARD land use change projections (both positive and negative changes in area) were broken into three categories for each region: annual crops, perennial crops and pasture.[DDDDDDD] We used a rule-based approach to determine the interaction of these three agricultural land uses with natural eco-systems in each region. These rules are summarized below in order of priority:

1. Annual and perennial crop areas interact with each other, e.g., where annual crop area increases and perennial crop area decreases, annual crops expand onto the land previously used for perennial crops.
2. Pasture and crop area interact with each other, e.g., where pasture area decreases and crop area increases, crops expand onto the land previously used for pasture.
3. Changes in the total area of land used for agriculture affect previously non-agricultural areas.

Following the 3 rules listed above, the FAPRI-CARD projections were disaggregated into 12 land conversion categories, where natural eco-systems include forests, grasslands, savannas, shrublands, wetlands and barren land:

- Annual Crops to/from Perennial Crops
- Pasture to/from Perennial Crops
- Pasture to/from Annual Crops
- Natural Ecosystems to/from Annual Crops
- Natural Ecosystems to/from Perennial Crops
- Natural Ecosystems to/from Pasture

Table 2.4-33 illustrates the results of this process with the results in Argentina for each scenario.[EEEEEEE] The FAPRI-CARD Results columns show the projected change in area for annual crops (Annl), perennial crops (Prnnl) and pasture (Pstr). Positive numbers indicate

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[DDDDDDD] The perennial crops included in the FAPRI-CARD model are sugarcane and palm oil.

[EEEEEEE] The results for all 54 FAPRI-CARD regions are included in the public docket.

expansion and negative numbers indicate contraction.  These results were translated into the 6 Land Conversion columns, where positive numbers indicate conversion in the direction shown in the header row, and negative numbers indicate a conversion in the opposite direction.  For example, in the Ntrl to Annl (i.e., Natural Ecosystems to Annual Crops) column, a positive number indicates conversion of natural ecosystems to annual crop production.  A negative number in the Ntrl to Annl column indicates reversion of annual crops back to natural ecosystems.

**Table 2.4-33.  Argentina Land Conversion Categories by Renewable Fuel, 2022 (Ha / billion BTU)**

| | *FAPRI-CARD Results* | | | *Land Conversions* | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Scenario | **Annl Crops** | **Prnnl Crops** | **Pstr** | Annl to Prnnl | Pstr to Prnnl | Pstr to Annl | Ntrl to Annl | Ntrl to Prrnl | Ntrl to Pstr |
| Corn Ethanol | **0.01** | **0.00** | **0.00** | 0.00 | 0.00 | 0.00 | 0.01 | 0.00 | 0.00 |
| Soy Biodiesel | **0.26** | **0.00** | **-0.48** | 0.00 | 0.00 | 0.26 | 0.00 | 0.00 | -0.22 |
| Sugarcane Ethanol | **-0.18** | **0.01** | **0.00** | 0.01 | 0.00 | 0.00 | -0.17 | 0.00 | 0.00 |
| Switchgrass Ethanol | **0.52** | **0.00** | **0.06** | 0.00 | 0.00 | 0.00 | 0.51 | 0.00 | 0.06 |

### 2.4.4.2.5.2 Evaluation of International Land Conversion Patterns with Satellite Data

In the proposed rule analysis land use change patterns were estimated at the national scale (and sub-national scale for key countries) using 1-km resolution MODIS products for the years 2001-2004.[568]  MODIS land cover products were chosen originally due to their global, multi-year coverage, low cost and homogenous classification scheme.  For the final rule analysis we used the higher resolution, and more recent, MODIS Version 5 (MODIS V5) land cover dataset which covers the years 2001-2007 with 500-meter resolution.

To assess the accuracy/uncertainty in our use of MODIS satellite data we performed a Monte Carlo analysis based on the underlying uncertainty in the satellite data as quantified by NASA.  The MODIS data set is routinely validated by NASA's MODIS land validation team.[FFFFFFF]  NASA uses several validation techniques for quality assurance and to develop uncertainty information for its products.  NASA's primary validation technique includes comparing the satellite classifications to data collected through field and aircraft surveys, and other satellite data sensors.  The accuracy of the MODIS V5 land cover product was assessed over a significant set of international locations, including roughly 1,900 sample site clusters covering close to 150 million square kilometers.  The results of these validation efforts are summarized in a "confusion matrix" which compares the satellite's land classifications with the actual land types observed on the ground.[569]  We used this information to assess and correct the accuracy and systematic biases in the published MODIS data.  Our analytical procedures are summarized below and discussed in more detail in a technical report by ICF International, Inc., available on the public docket.[570]  The full Monte Carlo model, with all data inputs and results, is also publicly available.

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[FFFFFFF] More information about the MODIS Land Validation procedures is available from the NASA Goddard Space Flight Center website, http://landval.gsfc.nasa.gov/

The key data source that allows us to understand the accuracy of the MODIS V5 product is a confusion matrix published by researchers that work as part of the MODIS land validation team. As explained by Dr. Mark Friedl:

> *The confusion matrix is a commonly used tool for assessment of accuracy for land cover classifications. The matrix scores how the classification process has labelled a series of test sites or test pixels at which the correct land cover label is known. Typically, the true class label is displayed across rows, while the actual mapped class is displayed in columns. The diagonal of the confusion matrix displays the number of sites or pixels for which the true class and the mapped class agree. The overall accuracy of the entire sample is then the sum of the diagonal elements divided by the total of all sites or pixels. For individual classes, the marginal totals of the matrix can easily be used to estimate the producer's accuracy and user's accuracy from the sample. The producer's accuracy is the probability that a pixel truly belonging to class i is also mapped as class i, while the user's accuracy is the probability that a pixel mapped as class i is truly of class i.*[571]

The MODIS V5 confusion matrix includes 17 land use/ land cover categories developed by the International Geosphere-Biosphere Programme (IGBP). As shown in Table 2.4-34, we aggregated the confusion matrix data to match the 10 land categories used in our analysis. The resulting aggregate confusion matrix is shown below in Table 2.4-36. Table 2.4-35 is a number key for the land cover classes presented in confusion matrix.

**Table 2.4-34. Aggregation of IGBP land cover classes into EPA land cover classes**

| IGBP Land Cover Class | EPA Land Cover Classes | |
|---|---|---|
| | Proposed Rule | Final Rule |
| Evergreen Needleleaf | Forest | Forest |
| Evergreen Broadleaf | Forest | Forest |
| Deciduous Needleleaf | Forest | Forest |
| Deciduous Broadleaf | Forest | Forest |
| Mixed Forest | Forest | Forest |
| Closed Shrubland | Shrubland | Shrubland |
| Open Shrubland | Shrubland | Shrubland |
| Woody Savanna | Savanna | Savanna |
| Savanna | Savanna | Savanna |
| Grasslands | Grassland | Grassland |
| Permanent Wetlands | Excluded | Wetland |
| Cropland | Cropland | Cropland |
| Cropland/Nat Veg Mosaic | Excluded | Mixed |
| Barren/Sparse | Excluded | Barren |
| Snow and Ice | Excluded | Excluded |
| Water | Excluded | Excluded |

## Table 2.4-35. EPA land cover class number key

| Number Key | EPA Land Cover Class |
|---|---|
| 1 | Annual Crops |
| 2 | Forest |
| 3 | Grassland |
| 4 | Mixed |
| 5 | Savanna |
| 6 | Shrubland |
| 7 | Wetland |
| 8 | Barren |
| 9 | Perennial Crops |
| 10 | Excluded |

## Table 2.4-36. MODIS Version 5 confusion matrix with aggregated EPA land cover classes

|  | *Satellite Classification Label* |  |  |  |  |  |  |  |  |  |
|---|---|---|---|---|---|---|---|---|---|---|
| *Training Site Label* | *1* | *2* | *3* | *4* | *5* | *6* | *7* | *8* | *10* | *Training Total* |
| *1* | 6,963 | 0 | 118 | 84 | 77 | 73 | 60 | 2 | 127 | *7,504* |
| *2* | 25 | 7,763 | 5 | 42 | 564 | 52 | 482 | 1 | 5 | *8,939* |
| *3* | 414 | 3 | 1,938 | 26 | 279 | 570 | 40 | 77 | 111 | *3,458* |
| *4* | 498 | 103 | 22 | 402 | 264 | 69 | 105 | 0 | 0 | *1,463* |
| *5* | 300 | 422 | 172 | 102 | 2,331 | 275 | 233 | 16 | 0 | *3,851* |
| *6* | 148 | 34 | 341 | 10 | 279 | 3,135 | 71 | 111 | 8 | *4,137* |
| *7* | 19 | 59 | 5 | 0 | 6 | 0 | 2,406 | 0 | 0 | *2,495* |
| *8* | 4 | 0 | 14 | 0 | 27 | 334 | 0 | 4,802 | 1 | *5,182* |
| *10* | 0 | 0 | 13 | 0 | 0 | 1 | 12 | 4 | 2,411 | *2,441* |
| *Satellite Total* | *8,371* | *8,384* | *2,628* | *666* | *3,827* | *4,509* | *3,409* | *5,013* | *2,663* | *39,470* |

Note: values for perennial crops (land class 9) were assigned with a procedure described in the ICF report.[572]

The confusion matrix contains information about the accuracy of the satellite data which can be used statistically to correct systematic biases. The matrix includes data from 39,470 training sites where the MODIS land team validated the satellite classification labels with on-the-ground training site surveys. For example, if we look at forest (land class 2) in the matrix, we see that of the 8,384 sites that were classified by the satellite as forest (see the satellite total row) 7,763 of these sites (see the diagonal in row 2) were correctly classified. The quotient of these figures (i.e. 7,763/8,384 = 92.6%) gives us what it is known as the producer's accuracy for forest. The user's accuracy for forest, 86.8%, can also be calculated by using the training site total for forest in the denominator (i.e., 7,763/8,939 = 86.8%).

Furthermore, we can determine which land classes forestlands tended to be misclassified as (i.e., confused with), which classes tended to be misclassified as forests, and the probability of each specific misclassification. Table 4 presents the producer's accuracy matrix for MODIS Version 5 using EPA's aggregated land classes. Each value in Table 2.4-37 gives the probability that a pixel reported as land cover R is actually land cover A, where R is the reported land class listed in the columns and A is the actual land cover listed in the rows. For example, the intersection of column 2 and row 5 shows that there was a 5.0% probability that a pixel reported as forest (land class 2) was actually savanna (land class 5).

**Table 2.4-37.**
**MODIS Version 5 producer's accuracy matrix with aggregated EPA land cover classes**

| | *Reported* | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| *Actual* | *1* | *2* | *3* | *4* | *5* | *6* | *7* | *8* | *10* |
| *1* | 83.2% | 0.0% | 4.5% | 12.6% | 2.0% | 1.6% | 1.8% | 0.0% | 4.8% |
| *2* | 0.3% | 92.6% | 0.2% | 6.3% | 14.7% | 1.2% | 14.1% | 0.0% | 0.2% |
| *3* | 4.9% | 0.0% | 73.7% | 3.9% | 7.3% | 12.6% | 1.2% | 1.5% | 4.2% |
| *4* | 5.9% | 1.2% | 0.8% | 60.4% | 6.9% | 1.5% | 3.1% | 0.0% | 0.0% |
| *5* | 3.6% | 5.0% | 6.5% | 15.3% | 60.9% | 6.1% | 6.8% | 0.3% | 0.0% |
| *6* | 1.8% | 0.4% | 13.0% | 1.5% | 7.3% | 69.5% | 2.1% | 2.2% | 0.3% |
| *7* | 0.2% | 0.7% | 0.2% | 0.0% | 0.2% | 0.0% | 70.6% | 0.0% | 0.0% |
| *8* | 0.0% | 0.0% | 0.5% | 0.0% | 0.7% | 7.4% | 0.0% | 95.8% | 0.0% |
| *10* | 0.0% | 0.0% | 0.5% | 0.0% | 0.0% | 0.0% | 0.4% | 0.1% | 90.5% |
| | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% | 100.0% |

Using the information in Table 2.4-37, it is fairly straight-forward to adjust/correct the reported land use data to provide a much better estimate of the actual land use during this time period. The MODIS data was corrected with the following multi-step process:

- First, the confusion matrix for each country and administrative unit is scaled for each year so that the share of reported land use of total land use matches the adjusted MODIS estimates share.
  - ACMcup = CM¬up /CMxp, where CMup are the values in the input aggregated confusion matrix and CMxp = ∑uCMup where u is the user's land use and p is the producer's land use [GGGGGGG]
  - The coefficients from the resulting matrix sum to 1.0
- Next, the number of producer sites is scaled similarly to the approach above and the producer's estimate is recalculated[HHHHHHH]
- The actual land use in 2001 and 2007 is then given by the following equations[IIIIII]
  - ALUci = ∑pBCMcyip * AMcpx for y = 2001 and where i is the initial land use
  - ALUcf = ∑pBCMcyfp * AMcxp for y = 2007 and where f is the final land use
- The reported land use change is then calculated first for 2001
  - We find a land use category where the total land use for 2001 decreased (ALUci < AMcix)
  - We scale the land use change to all land uses down from that land use category based on the percentage decrease in total land use
  - We allocate the remaining land use change to the remaining land uses in 2001 based on the share of the increase in land use that increased
- We then use a similar process to adjust the 2007 land use

As an example of the 2nd to last step, let's assume that, based on the confusion matrix adjustment procedure described above, the adjusted land use for savanna has decreased in 2001 from the producer values by 30%, from 21 to 14 million hectares and that the adjusted land use for cropland and forestland, and grassland increase by 5, 3, and 2 million hectares respectively and all other land uses decrease or do not change. The adjusted land use change from Savanna to all 10 land uses is then scaled to be 70% of the original land use change from Savanna. The remaining 30% of the land use change is then allocated as coming from cropland, forestland, and grassland with the shares equal to 5/(5+3+2) = 5/10 for cropland,3/10 for forestland, and 2/10 for grassland respectively. This means that 3.5, 2.1, and 1.4 million hectares of increased cropland, forestland, and grassland have been accounted for and the ratios to apply to the land use change from Savanna is 0.5*0.3, 0.3*0.3, and 0.2*0.3 respectively. If the Savanna to Cropland land use change was 1 million hectares originally, it is now 0.7 million hectares. If the Cropland, Forestland, and Grassland to Cropland land use change was 2, 0.1, 0.4 million hectares originally, they are 2.0 + 1.0 * 0.5 * 0.3, 0.1 + 1.0*0.3*0.3, and 0.4 + 1.0*0.2 or 2.15, .19, and .6 respectively. We then go to the next land use with reductions in the adjusted land use for 2001

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[GGGGGGG] x is a placeholder that indicates that the matrix presents total land use.
[HHHHHHH] In fact, the producer's estimate does not change.
[IIIIII] x is a placeholder that indicates that the matrix presents total land use.

and repeat this process but in the allocation, we use (5-3.5), (3-2.1), and (2-1.4) million hectares for the allocation for cropland, forestland, and grassland respectively.

The approach for the adjustments in land use for 2007 is similar, but it scales and adds using (i) the change in land use in 2007, instead of change in land use in 2001, and (ii) the land use change from the 10 land uses to Savanna, instead of the change from Savanna to the 10 land uses.

The corrected satellite data was used to evaluate the types of land affected by the projected land conversions in each scenario. For agricultural expansions, the types of land affected were evaluated with the corrected land use change data from 2001-2007. We also used this approach to determine, within each country/region, the location of land use changes, i.e. the Administrative Units where conversions would occur. For example, in each region we looked at the types of land converted to cropland during this time period.

To determine the types of land converted to pasture, we applied the land use change data for cropland. This was done primarily because the MODIS data set does not classify land used for pasture. MODIS does classify grasslands and savanna, which we know are used for livestock grazing, but it provides no information about the share of grassland and savanna used as pasture in each region. Thus, looking only at land types that were replaced by grassland or savanna would ignore the fact that pasture can expand onto grassland and savanna areas. By applying the cropland change data for pasture we included/approximated these important land conversion possibilities. The justification for this approach was based, in part, on the assumption that pasture expansion is likely to affect similar land types as cropland.[JJJJJJJ]

For land reversions, land cover in 2007 was used to estimate the land types that would likely grow back on abandoned agricultural lands in each region. For example, in a region that was 80% forest, we assume that 80% of abandoned agricultural land would grow back as forest. For land reversions this approach was preferable to using change data, because the time period covered by the MODIS satellite imagery was not long enough to determine the final land category following reversion, i.e., 30 years later. We also used this approach to determine, within each country/region, the location of land reversions, i.e. the Administrative Units where reversions would occur.

The contributing land use change categories and the bases of their weighting factors for each agricultural land use change are presented in Table 2.4-38. The first column lists the 12 land conversion categories modeled. The middle column indicates the satellite data weighting approach used. The last column includes the resulting land conversions, which were weighted with the approach listed in the middle column. More details about the application of satellite data to weight land conversions is provided in a technical report by ICF International available on the public docket.[573]

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[JJJJJJJ] This assumption is supported to some degree by Cardille and Foley (2003) who found that cropland and pasture expansion affected similar land types in the Brazilian Amazonia between 1980 and 1995.

## Table 2.4-38.
## Contributing Land Use Change Categories and Bases of Weighting Factors for Agricultural Land Use Change Categories

| Agricultural Land Use Change Category | Land Use Change or Land Use Used to Estimate Weighted Emission Factors | Land Use Change Category or Land Use Type |
|---|---|---|
| Annual Crops to Perennial Crops | 2007 Land Use | Cropland |
| Perennial Crops to Annual Crops | 2007 Land Use | Cropland |
| Pasture to Perennial Crops | Land Use Change - 2001 to 2007 | Grasslands to Perennial |
| | | Savanna to Perennial |
| Perennial Crops to Pasture | Land Use Change - 2001 to 2007 | Perennial to Grasslands |
| | | Perennial to Savanna |
| Pasture to Annual Crops | Land Use Change - 2001 to 2007 | Grasslands to Croplands |
| | | Savanna to Croplands |
| Annual Crops to Pasture | Land Use Change - 2001 to 2007 | Croplands to Grasslands |
| | | Croplands to Savanna |
| Natural Ecosystems to Annual Crops | Land Use Change - 2001 to 2007 | Forestland to Croplands |
| | | Grasslands to Croplands |
| | | Mixed to Croplands |
| | | Savanna to Croplands |
| | | Shrubland to Croplands |
| | | Wetland to Croplands |
| | | Barren to Croplands |
| Annual Crops to Natural Ecosystems | 2007 Land Use | Forestland |
| | | Grasslands |
| | | Mixed |
| | | Savanna |
| | | Shrubland |
| Natural Ecosystems to Perennial Crops | Land Use Change - 2001 to 2007 | Forestland to Perennial |
| | | Grasslands to Perennial |
| | | Mixed to Perennial |
| | | Savanna to Perennial |
| | | Shrubland to Perennial |
| | | Wetland to Perennial |
| | | Barren to Perennial |
| Perennial Crops to Natural Ecosystems | 2007 Land Use | Forestland |
| | | Grasslands |
| | | Mixed |
| | | Savanna |

| Agricultural Land Use Change Category | Land Use Change or Land Use Used to Estimate Weighted Emission Factors | Land Use Change Category or Land Use Type |
|---|---|---|
| | | Shrubland |
| Natural Ecosystems to Pasture | Land Use Change - 2001 to 2007 | Forestland to Grasslands |
| | | Shrubland to Grasslands |
| | | Mixed to Grasslands |
| | | Wetland to Grasslands |
| | | Barren to Grasslands |
| | | Forestland to Savanna |
| | | Shrubland to Savanna |
| | | Mixed to Savanna |
| | | Wetland to Savanna |
| | | Barren to Savanna |
| Pasture to Natural Ecosystems | 2007 Land Use[KKKKKKK] | Forestland |
| | | Mixed |
| | | Shrubland |

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[KKKKKKK] The model actually uses the three land uses twice, once to represent the replacement of grasslands and the other to represent the replacement of Savanna

Table 2.4-39 includes the regional shares of land types converted to cropland and pasture based on the original Version 5 MODIS data. Table 2.4-40 shows the same data after it was corrected using the confusion matrix data and the procedure described above. In many regions, the corrections significantly reduced the share of grassland, savanna and/or mixed land converted to cropland. This was due, in part, to the tendency of MODIS to confuse these land types with each other and with cropland. As a result, the share of forest affected by agricultural expansion increased for most of the regions analyzed. Table 2.4-41 shows the land type shares for agricultural reversion with the corrected data. Our estimates of satellite data uncertainty are presented in below in Table 2.4-49.

# Table 2.4-39. Types of Land Converted to Cropland/Pasture by Region Original Version 5 MODIS Data, 2001-2007

| FAPRI-CARD Region | Forest | Grassland | Mixed | Savanna | Shrubland | Wetland | Barren |
|---|---|---|---|---|---|---|---|
| Algeria | 0% | 12% | 7% | 8% | 72% | 0% | 0% |
| Argentina | 11% | 37% | 20% | 17% | 13% | 1% | 0% |
| Australia | 1% | 54% | 2% | 16% | 27% | 0% | 0% |
| Bangladesh | 21% | 6% | 24% | 24% | 11% | 13% | 1% |
| Brazil: Amazon Biome | 15% | 33% | 12% | 36% | 4% | 0% | 0% |
| Brazil: Central-West Cerrados | 3% | 30% | 17% | 49% | 1% | 0% | 0% |
| Brazil: Northeast Coast | 0% | 22% | 15% | 54% | 9% | 0% | 0% |
| Brazil: North-Northeast Cerrados | 1% | 32% | 7% | 53% | 7% | 0% | 0% |
| Brazil: South | 5% | 52% | 22% | 20% | 0% | 0% | 0% |
| Brazil: Southeast | 1% | 20% | 43% | 35% | 1% | 0% | 0% |
| Canada | 2% | 52% | 5% | 5% | 32% | 0% | 3% |
| China | 1% | 67% | 6% | 3% | 15% | 0% | 7% |
| New Zealand | 30% | 37% | 6% | 2% | 24% | 0% | 0% |
| Colombia | 3% | 74% | 5% | 14% | 4% | 0% | 0% |
| Cuba | 2% | 6% | 74% | 15% | 2% | 1% | 0% |
| Egypt | 2% | 4% | 50% | 4% | 27% | 0% | 13% |
| EU | 4% | 37% | 36% | 8% | 14% | 0% | 1% |
| Guatemala | 17% | 3% | 60% | 18% | 1% | 0% | 0% |
| India | 2% | 12% | 41% | 23% | 22% | 0% | 1% |
| Indonesia | 27% | 5% | 43% | 22% | 2% | 2% | 0% |
| Iran | 0% | 77% | 1% | 1% | 16% | 0% | 4% |
| Iraq | 0% | 53% | 4% | 2% | 39% | 0% | 2% |
| Ivory Coast | 26% | 6% | 30% | 30% | 6% | 2% | 1% |
| Japan | 8% | 9% | 58% | 15% | 10% | 0% | 0% |
| Malaysia | 35% | 4% | 50% | 5% | 3% | 3% | 0% |
| Mexico | 2% | 36% | 17% | 16% | 29% | 0% | 0% |
| Morocco | 0% | 18% | 4% | 4% | 72% | 0% | 2% |
| Myanmar | 7% | 9% | 46% | 27% | 10% | 2% | 0% |
| Nigeria | 2% | 73% | 12% | 11% | 2% | 0% | 0% |
| Other Africa | 0% | 59% | 8% | 18% | 11% | 0% | 3% |
| Other Asia | 0% | 79% | 2% | 1% | 6% | 0% | 11% |
| Other CIS | 0% | 87% | 2% | 1% | 4% | 0% | 5% |
| Other Eastern Europe | 1% | 48% | 38% | 9% | 4% | 0% | 0% |
| Other Latin America | 7% | 40% | 13% | 19% | 20% | 0% | 1% |
| Other Middle East | 0% | 13% | 13% | 8% | 54% | 0% | 11% |
| Pakistan | 0% | 13% | 29% | 3% | 51% | 0% | 4% |
| Paraguay | 8% | 31% | 22% | 39% | 0% | 0% | 0% |
| Peru | 1% | 78% | 2% | 3% | 15% | 0% | 0% |
| Philippines | 12% | 2% | 78% | 4% | 1% | 3% | 0% |
| Rest of World | 1% | 54% | 9% | 22% | 12% | 0% | 1% |
| Russia | 3% | 50% | 25% | 6% | 16% | 0% | 0% |
| South Africa | 1% | 52% | 12% | 18% | 17% | 0% | 0% |
| South Korea | 5% | 5% | 82% | 6% | 3% | 0% | 0% |
| Taiwan | 25% | 6% | 36% | 15% | 16% | 1% | 1% |
| Thailand | 5% | 10% | 64% | 15% | 4% | 1% | 0% |
| Tunisia | 0% | 8% | 10% | 3% | 79% | 0% | 1% |
| Turkey | 0% | 81% | 3% | 6% | 9% | 0% | 0% |
| Ukraine | 2% | 26% | 59% | 7% | 6% | 0% | 0% |
| Uruguay | 2% | 82% | 13% | 3% | 0% | 0% | 0% |
| US | 0% | 84% | 5% | 4% | 7% | 0% | 0% |
| Uzbekistan | 0% | 56% | 3% | 3% | 20% | 0% | 18% |
| Venezuela | 1% | 38% | 8% | 36% | 16% | 0% | 0% |
| Vietnam | 16% | 5% | 55% | 11% | 4% | 7% | 1% |
| Western Africa | 2% | 15% | 34% | 46% | 3% | 0% | 0% |

## Table 2.4-40. Types of Land Converted to Cropland/Pasture by Region Corrected Version 5 MODIS Data, 2001-2007

| FAPRI-CARD Region | Forest | Grassland | Mixed | Savanna | Shrubland | Wetland | Barren |
|---|---|---|---|---|---|---|---|
| Algeria | 1% | 16% | 8% | 10% | 64% | 0% | 0% |
| Argentina | 12% | 26% | 27% | 17% | 14% | 1% | 3% |
| Australia | 6% | 32% | 11% | 22% | 25% | 0% | 4% |
| Bangladesh | 19% | 21% | 24% | 20% | 11% | 5% | 1% |
| Brazil: Amazon Biome | 54% | 8% | 15% | 20% | 2% | 1% | 0% |
| Brazil: Central-West Cerrados | 11% | 26% | 20% | 36% | 6% | 0% | 0% |
| Brazil: Northeast Coast | 11% | 19% | 19% | 41% | 8% | 0% | 1% |
| Brazil: North-Northeast Cerrados | 15% | 16% | 10% | 49% | 9% | 0% | 1% |
| Brazil: South | 13% | 23% | 28% | 29% | 6% | 0% | 0% |
| Brazil: Southeast | 10% | 18% | 30% | 36% | 6% | 0% | 0% |
| Canada | 8% | 28% | 13% | 14% | 31% | 2% | 4% |
| China | 6% | 30% | 23% | 20% | 17% | 1% | 3% |
| New Zealand | 28% | 33% | 15% | 7% | 15% | 1% | 1% |
| Colombia | 33% | 9% | 31% | 18% | 8% | 1% | 1% |
| Cuba | 9% | 12% | 49% | 23% | 7% | 0% | 0% |
| Egypt | 2% | 20% | 30% | 8% | 33% | 0% | 7% |
| EU | 6% | 25% | 32% | 21% | 14% | 1% | 1% |
| Guatemala | 21% | 7% | 42% | 24% | 5% | 1% | 0% |
| India | 10% | 21% | 30% | 19% | 17% | 1% | 2% |
| Indonesia | 39% | 5% | 29% | 22% | 3% | 2% | 0% |
| Iran | 2% | 43% | 5% | 8% | 33% | 0% | 9% |
| Iraq | 1% | 37% | 8% | 8% | 43% | 0% | 3% |
| Ivory Coast | 22% | 8% | 15% | 46% | 8% | 0% | 1% |
| Japan | 8% | 9% | 47% | 23% | 11% | 1% | 1% |
| Malaysia | 52% | 3% | 27% | 13% | 2% | 2% | 0% |
| Mexico | 10% | 18% | 27% | 21% | 21% | 1% | 2% |
| Morocco | 2% | 28% | 7% | 9% | 50% | 0% | 4% |
| Myanmar | 14% | 10% | 34% | 30% | 9% | 2% | 1% |
| Nigeria | 11% | 36% | 19% | 25% | 9% | 0% | 1% |
| Other Africa | 10% | 19% | 14% | 37% | 13% | 0% | 6% |
| Other Asia | 4% | 42% | 15% | 11% | 19% | 0% | 9% |
| Other CIS | 1% | 49% | 17% | 11% | 18% | 0% | 3% |
| Other Eastern Europe | 6% | 37% | 31% | 16% | 8% | 1% | 1% |
| Other Latin America | 18% | 13% | 27% | 26% | 13% | 1% | 2% |
| Other Middle East | 2% | 21% | 11% | 11% | 32% | 0% | 23% |
| Pakistan | 3% | 23% | 28% | 13% | 31% | 0% | 2% |
| Paraguay | 17% | 20% | 22% | 36% | 5% | 1% | 0% |
| Peru | 45% | 30% | 4% | 9% | 10% | 1% | 1% |
| Philippines | 16% | 5% | 54% | 19% | 2% | 3% | 0% |
| Rest of World | 18% | 13% | 25% | 27% | 12% | 1% | 3% |
| Russia | 8% | 20% | 27% | 20% | 22% | 1% | 2% |
| South Africa | 5% | 35% | 19% | 18% | 20% | 0% | 3% |
| South Korea | 5% | 11% | 58% | 20% | 5% | 1% | 0% |
| Taiwan | 25% | 8% | 27% | 21% | 17% | 1% | 1% |
| Thailand | 12% | 10% | 48% | 23% | 5% | 1% | 0% |
| Tunisia | 3% | 29% | 12% | 12% | 43% | 0% | 1% |
| Turkey | 5% | 45% | 15% | 10% | 23% | 0% | 3% |
| Ukraine | 3% | 31% | 20% | 32% | 13% | 2% | 1% |
| Uruguay | 3% | 57% | 17% | 11% | 12% | 0% | 0% |
| US | 6% | 36% | 24% | 18% | 14% | 1% | 1% |
| Uzbekistan | 2% | 34% | 16% | 15% | 32% | 0% | 1% |
| Venezuela | 7% | 13% | 27% | 43% | 9% | 0% | 1% |
| Vietnam | 21% | 8% | 39% | 20% | 6% | 5% | 1% |
| Western Africa | 14% | 12% | 14% | 50% | 8% | 0% | 1% |

## Table 2.4-41. Types of Land That Replace Abandoned Cropland/Pasture by Region
## *Corrected* Version 5 MODIS Data, 2001-2007

| FAPRI-CARD Region | Forest | Grassland | Mixed | Savanna | Shrubland |
|---|---|---|---|---|---|
| Algeria | 3% | 21% | 3% | 10% | 64% |
| Argentina | 14% | 21% | 6% | 13% | 45% |
| Australia | 7% | 20% | 3% | 19% | 51% |
| Bangladesh | 32% | 14% | 20% | 24% | 9% |
| Brazil: Amazon Biome | 83% | 1% | 5% | 10% | 1% |
| Brazil: Central-West Cerrados | 24% | 9% | 11% | 49% | 6% |
| Brazil: Northeast Coast | 14% | 10% | 15% | 54% | 7% |
| Brazil: North-Northeast Cerrados | 20% | 9% | 11% | 53% | 7% |
| Brazil: South | 32% | 17% | 23% | 23% | 5% |
| Brazil: Southeast | 21% | 7% | 22% | 44% | 6% |
| Canada | 43% | 11% | 4% | 15% | 26% |
| China | 27% | 34% | 10% | 16% | 14% |
| New Zealand | 64% | 14% | 2% | 6% | 13% |
| Colombia | 64% | 8% | 11% | 14% | 4% |
| Cuba | 36% | 7% | 33% | 21% | 4% |
| Egypt | 2% | 30% | 8% | 10% | 50% |
| EU | 45% | 11% | 15% | 17% | 11% |
| Guatemala | 54% | 3% | 17% | 23% | 3% |
| India | 22% | 12% | 24% | 29% | 13% |
| Indonesia | 77% | 1% | 12% | 9% | 1% |
| Iran | 3% | 36% | 3% | 8% | 51% |
| Iraq | 2% | 25% | 3% | 8% | 62% |
| Ivory Coast | 32% | 5% | 20% | 38% | 4% |
| Japan | 77% | 2% | 8% | 11% | 2% |
| Malaysia | 82% | 1% | 10% | 7% | 1% |
| Mexico | 19% | 17% | 8% | 24% | 32% |
| Morocco | 2% | 18% | 4% | 10% | 66% |
| Myanmar | 59% | 4% | 12% | 22% | 3% |
| Nigeria | 17% | 18% | 25% | 33% | 7% |
| Other Africa | 24% | 17% | 8% | 36% | 15% |
| Other Asia | 13% | 52% | 5% | 9% | 22% |
| Other CIS | 5% | 64% | 4% | 8% | 19% |
| Other Eastern Europe | 42% | 8% | 29% | 17% | 4% |
| Other Latin America | 56% | 7% | 8% | 15% | 14% |
| Other Middle East | 1% | 20% | 2% | 8% | 68% |
| Pakistan | 5% | 17% | 8% | 10% | 60% |
| Paraguay | 41% | 8% | 14% | 33% | 5% |
| Peru | 62% | 17% | 2% | 7% | 12% |
| Philippines | 54% | 3% | 30% | 12% | 1% |
| Rest of World | 44% | 11% | 9% | 20% | 16% |
| Russia | 43% | 10% | 6% | 14% | 27% |
| South Africa | 8% | 22% | 6% | 23% | 42% |
| South Korea | 67% | 3% | 13% | 13% | 3% |
| Taiwan | 75% | 3% | 9% | 10% | 3% |
| Thailand | 32% | 5% | 34% | 25% | 3% |
| Tunisia | 3% | 17% | 5% | 10% | 65% |
| Turkey | 12% | 47% | 7% | 16% | 18% |
| Ukraine | 34% | 14% | 32% | 16% | 5% |
| Uruguay | 4% | 67% | 5% | 11% | 13% |
| US | 27% | 31% | 14% | 12% | 16% |
| Uzbekistan | 2% | 40% | 3% | 9% | 46% |
| Venezuela | 55% | 8% | 11% | 21% | 4% |
| Vietnam | 48% | 5% | 21% | 22% | 4% |
| Western Africa | 14% | 8% | 17% | 54% | 7% |

### 2.4.4.2.6 Quantification of International Land Conversion GHG Emissions Impacts

Land use change emissions factors were calculated by the non-profit organization Winrock International following 2006 IPCC Agriculture Forestry and Other Land Use (AFOLU) Guidelines.[574] Winrock's staff is highly regarded for their years of experience and accomplishments in this field, including their work with the IPCC to develop the AFOLU Guidelines. Following publication of the proposed rule, we sponsored an expert peer review on this part of our lifecycle analysis. Based on the reviewers recommendations a number of important improvements were made, including incorporation of more recent and higher resolution data sets. Our analysis of land use change emissions factors has also been expanded to provide global coverage. For the proposed rule, emissions factors were estimated for 5 land categories in 314 regions across 35 of the most important countries, with a weighted average applied to the rest of the world. Our analysis now includes 9 land categories in over 750 distinct regions across 160 countries covering all significant agricultural producers. This section describes the methods used to estimate GHG emissions from international land use change, with a focus on updates since the proposed rule. More details are available in a technical document by Winrock available on the public docket.[575]

#### 2.4.4.2.6.1 Data Sources and Methods for International Land Conversion GHG Emissions Factors

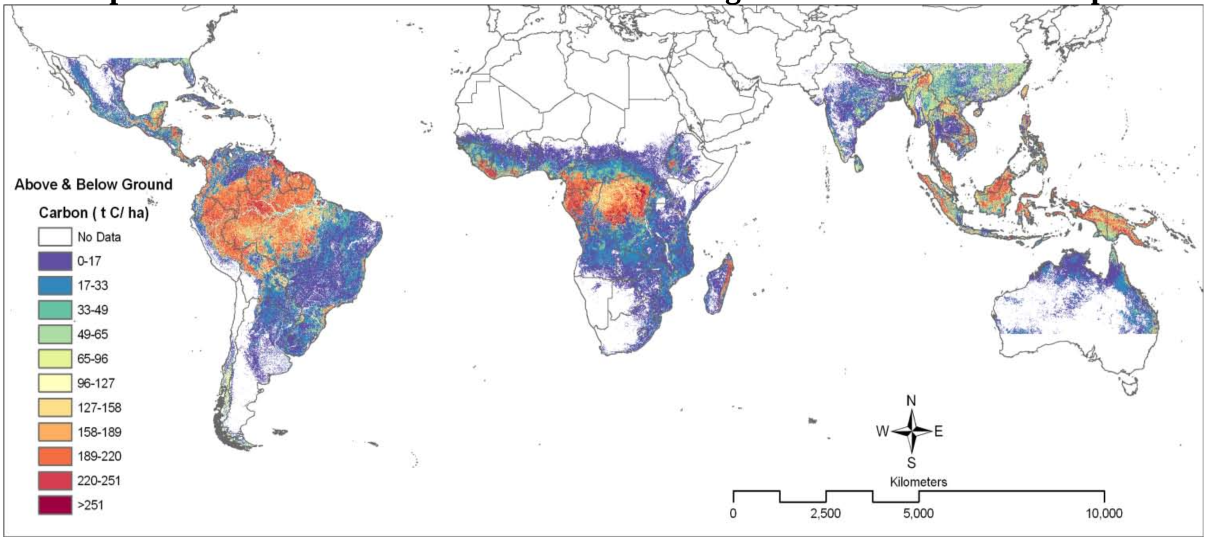
Emission factors were calculated using the IPCC equations explained in DRIA Chapter 2.[576] The emissions factors include the sum of changes in above- and belowground biomass carbon stocks, changes in soil carbon stocks on mineral soils, emissions from peat drainage on peat soils cleared for agriculture, foregone forest sequestration, and non-CO2 emissions (CH4, N2O) resulting from land clearing with fire where applicable. Methane emissions from rice cultivation were excluded from the updated emission factors, as these emissions are accounted for elsewhere in EPA's lifecycle analysis. Updates to various components of the final emission factor are described below.

##### 2.4.4.2.6.1.1 Data Sources and Methods for International Forest Carbon Stock Estimates

Our emission factor analysis incorporated spatial maps of forest carbon stocks from several data sources. The region-specific maps were preferred due to the use of country-specific data (i.e., IPCC Tier 2 vs. Tier 1), and also because the only globally consistent carbon stock map available was derived using adjusted biome-level Tier 1 default values from IPCC rather than from country specific data sources (Ruesch and Gibbs 2008). We used regional and/or country-level maps where available, and the global Ruesch and Gibbs (2008) data product was used only to fill in gaps where no other information on forest carbon stocks was available.[577]

Our analysis of forest carbon stocks was improved by incorporating several new data sources. Most notable is the inclusion of a new spatially explicit map of tropical forest carbon stocks. Winrock is working with Dr. Sassan Saatchi from NASA's Jet Propulsion Laboratory to create a pantropical benchmark map of above- and belowground forest carbon stocks for the year 2000 at 1-km resolution.[578] The methodology uses about 4,000 ground inventory plots of forest biomass, 150,000 biomass values estimated from heights measured by spaceborne lidar, and a suite of satellite imagery products to derive a spatially refined map of aboveground forest carbon at a 1-km grid cell resolution. Belowground carbon is added to aboveground carbon using an equation from Mokany et al. (2006).[579] The estimates are directly comparable across countries and regions due to the consistency in the methodological approach (see Figure 2.4-32).

**Figure 2.4-32.**
**Map of forest carbon stocks in above- and belowground biomass for the tropics**

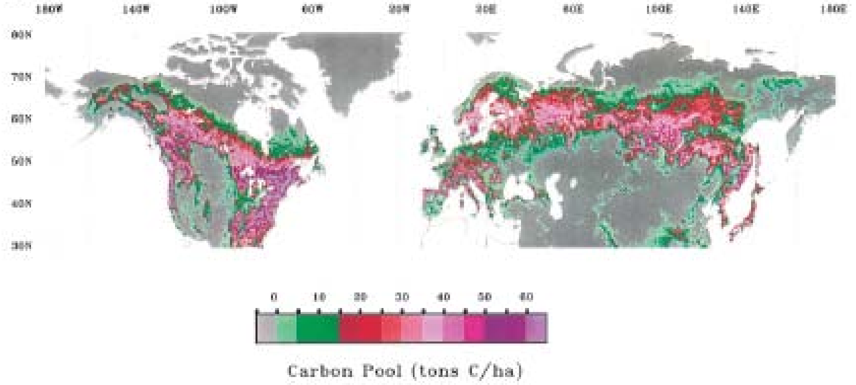


Note: from Saatchi et al. (in prep)

Preliminary results of Saatchi et al. for forest carbon stocks in Latin America and Africa were incorporated into the updated EPA analysis by clipping the map to MODIS forest cover in 2001 and calculating the area-weighted average forest carbon stock per country (and per administrative unit in key countries). Preliminary results for Asia are now complete, but were not included in the updated EPA analysis due to timing considerations. Therefore, the original Brown et al. (2001) map was retained for forest carbon stock estimates in Asia.[580] The Saatchi et al. results represent a significant improvement over previous estimates; the maps were evaluated for accuracy using cross validation with approximately 50% of the ground and lidar biomass data and resulted in an overall accuracy of 76% across the three regions (Latin America: 81%, Africa: 86%, Southeast Asia: 69%).

Myneni et al. (2001) also produced a spatially-explicit map of woody biomass for Northern (i.e., boreal and temperate) forests (Figure 2.4-33).[581] Although we used carbon stock values from other data sources for the United States, Russia and many countries of the European Union (Blackard et al. 2007, Houghton et al. 2007, Nabuurs et al. 2003, see Figure 2.4-34), the Myneni et al. (2001) dataset filled in the data gap for Canada and many Eastern European countries.[582,583,584,585]

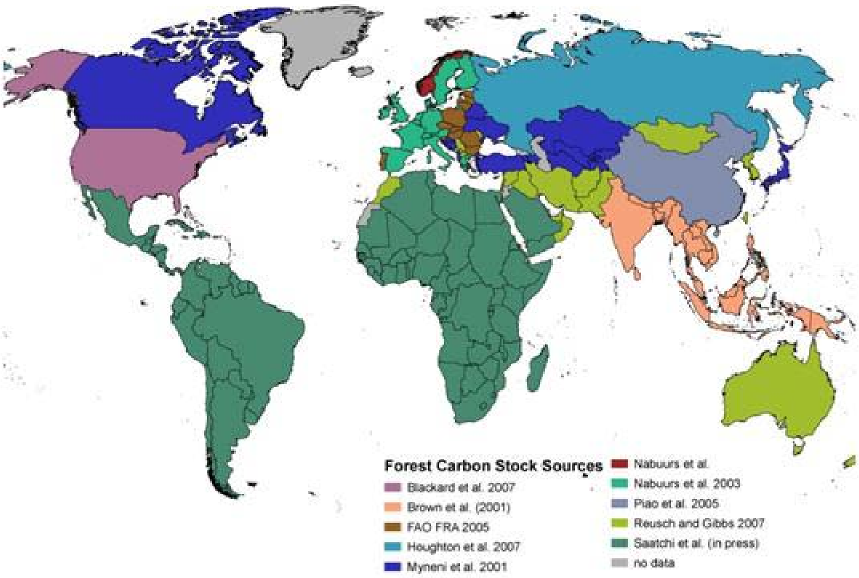
**Figure 2.4-33. Aboveground biomass carbon stocks in Northern forests**



Note: reproduced from Figure 2 of Myneni et al. (2001).

Apart from the new data sources described above, the data sources used to estimate forest carbon stocks in other regions remained unchanged in the updated analysis. [586] A summary of data sources used is shown in Figure 2.4-34.

**Figure 2.4-34.**
**Data sources used for estimating forest carbon stocks in updated emission factor analysis**

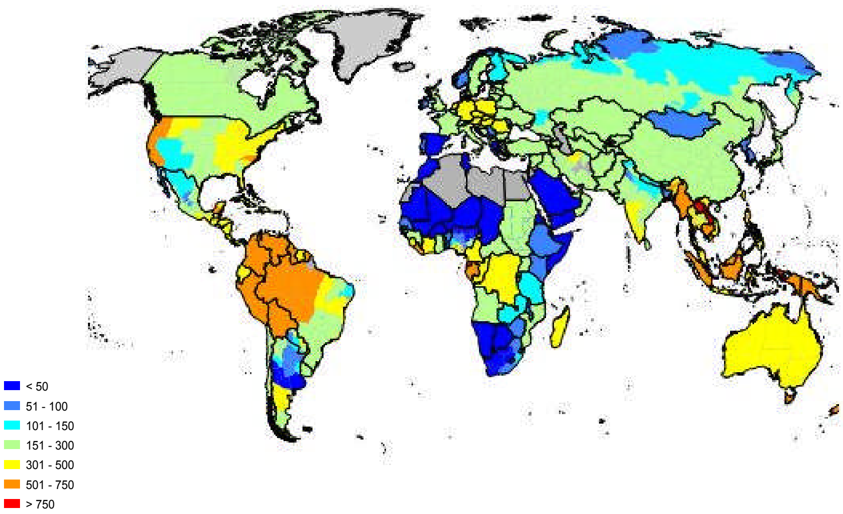


Note: Nabuurs et al. and Nabuurs et al. 2003 are the same data source.

In all cases where belowground biomass was not estimated, belowground biomass was added to aboveground biomass estimates using an equation from Mokany et al. (2006).[587] (This equation represents an update to the default belowground biomass values given in the IPCC

Guidelines.) Forest carbon stock values per country or administrative unit (for key countries) are shown in Figure 2.4-35.

**Figure 2.4-35. Spatially averaged forest carbon stocks in above- and belowground biomass (tCO2e/ha)**



2.4.4.2.6.1.2 Data Sources and Methods for International Cropland Carbon Stock Estimates

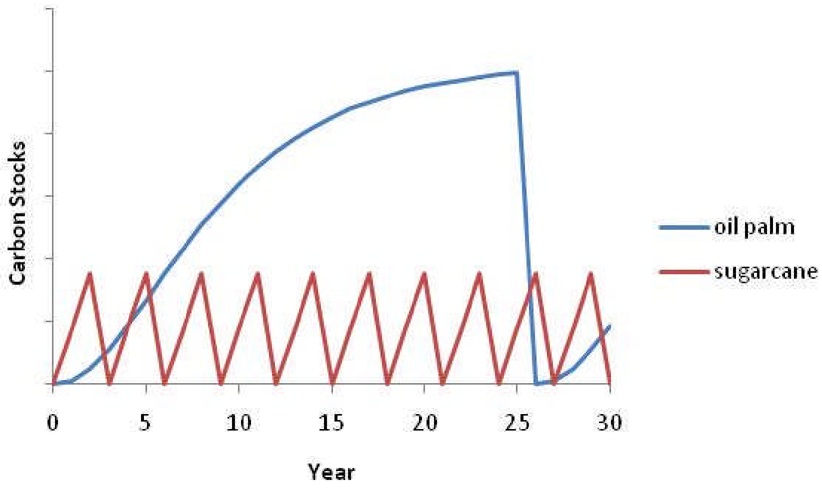
In the proposed rule emission factor analysis, all cropland conversion was assumed to be conversion to annual cropland. In the updated analysis, emission factors were estimated separately for conversion to annual cropland and conversion to perennial cropland. Perennial cropland in Indonesia and Malaysia was assumed to be oil palm, while perennial cropland in all other countries was sugarcane. Carbon stocks in oil palm plantations after one year of growth were estimated as 15 t CO2e/ha. Table 5.3 of the 2006 IPCC Guidelines for AFOLU gives biomass stocks on oil palm plantation as 136 t/ha (68 t C/ha), and if this value is divided by an assumed 15-year growth period, a linear growth rate of 4 t C/ha/yr (15 t CO2e/ha/yr) was assumed. This value is also nearly identical to the average carbon stock in biomass after one year of growth averaged across all tropical climate regions and all perennial crop types, as given in Table 5.9 of the 2006 IPCC Guidelines.

Carbon stocks in sugarcane after one year of growth were assumed to be 44 t CO2e/ha. (Carbon stocks for long-lived tree species such as oil palm accumulate carbon more slowly in the early phases of growth.) The value for sugarcane was derived from estimates of carbon stocks in sugarcane in aboveground biomass (17 t C ha-1 or 62 t CO2, Amaral et al. 2008)[588] and in belowground biomass (7 t C/ha or 26 t CO2/ha, Smith et al. 2005)[589] for a total of 88 t CO2e/ha. We assumed a growth period of two years to achieve full carbon stocks, therefore the carbon stock in sugarcane after one year of growth was assumed to be 44 t CO2/ha.

All biomass accumulated after Year 1 would have been harvested over the course of 30 years in the case of both sugarcane and oil palm, leading to little net sequestration during the time period for which emission factors were estimated (30 years). Over the long term (e.g., 100 years), oil palm plantations may have a long-term average carbon stock higher than that at Year 1, but the land use after 30 years is highly uncertain and there is no guarantee of future rotations. Therefore, the average carbon sequestration at any given time over 30 years was assumed to be the carbon stock in vegetation after one year of growth.

Figure 2.4-36 illustrates this concept by showing an example of carbon stock growth for perennial crops with different rotation lengths.

**Figure 2.4-36. Perennial Crop Carbon Stocks Over Time**



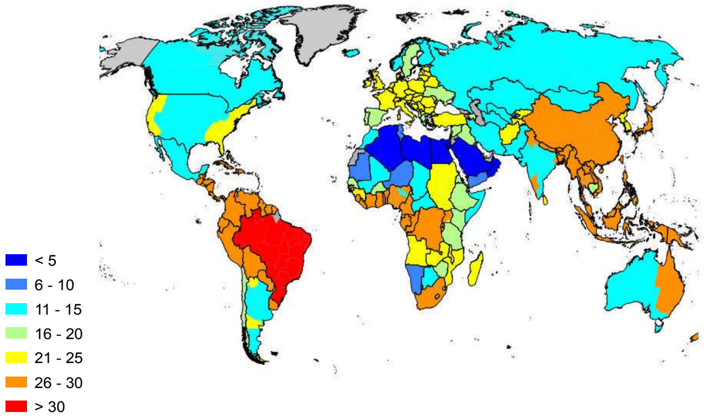
2.4.4.2.6.1.3 Data Sources and Methods for International Grassland, Savanna and Shrubland Carbon Stock Estimates

The approach for estimating carbon stocks in grassland, savanna and shrubland land cover categories was unchanged from the proposed rule, as there were no significant comments on this aspect of our analysis from the peer reviewers. Above- and belowground carbon stocks of grassland, savanna and shrublands in Brazil were estimated using values from de Castro and Kauffman (1998)[590] who report biomass along a vegetation gradient from campo limpo (pure grassland), campo sujo (a savanna with a sparse presence of shrubs), campo cerrado (a dominance of shrubs with scattered trees and a grass understory), cerrado sensu stricto (a dominance of trees with scattered shrubs and a grass understory) and cerradão (a closed canopy forest) (Coutinho 1978, Eiten 1972, Goodland & Pollard 1973).[591,592,593] Shrubland carbon stocks in Brazil were estimated as the average of biomass values reported for cerrado aberto and cerrado denso. Savanna carbon stocks in Brazil were estimated as the average biomass value reported for campo sujo and grassland carbon stocks in Brazil were estimated as the average value reported for campo limpo.

To maintain a consistent approach, for all countries except Brazil (explained in the paragraph above), carbon stocks in grasslands were estimated based on default biomass values given in Table 6.4 of the IPCC AFOLU Guidelines. These default values are presented by ecological zone. Therefore, grassland C stocks within each country reflect the area-weighted value based on the proportions of each ecological zone present within each country. Carbon stocks of savanna and shrubland land cover types in all countries except Brazil were estimated using a proportional approach based on the Brazil dataset, which indicates an increasing trend in carbon stocks from grassland to savanna to shrubland in a ratio of 1 to 1.8 to 3.4. These ratios were applied to other countries for estimating carbon stocks in savanna and shrubland based on the estimated carbon stocks of grassland within each country.

Grassland carbon stock estimates for each country and administrative unit (for key countries) are shown in Figure 2.4-37.

**Figure 2.4-37. Grassland carbon stock estimates for each country and administrative unit (t CO2e/ha)**



### 2.4.4.2.6.1.4 Data Sources and Methods for International Wetland, Barren and Mixed Carbon Stock Estimates

In line with recommendations for the expert peer reviewers, the updated analysis included land cover change to/from the wetland and barren land cover categories, and therefore emission factors were estimated for these conversions. According to the IGBP land cover description, the permanent wetlands category can consist of herbaceous and/or woody vegetation. However, after confirming that Indonesian peat swamp forests (a type of permanent forested wetland) are classified as forest and not wetland in the MODIS land cover maps, the carbon stocks of permanent wetlands in a given country or administrative unit were calculated as the average of carbon stocks in shrubland and grassland land cover categories. Carbon stocks on barren lands were assumed to be zero. In accordance with the IGBP land cover definitions, mixed carbon stocks were calculated as the average of forest, shrubland, grassland and cropland carbon stocks.

### 2.4.4.2.6.2 Evaluation of Changes in Biomass Carbon Stocks from International Land Conversions

Initial changes in biomass carbon stocks on land converted to another land category (e.g., from forest to cropland) were calculated the same way as in the proposed rule analysis, i.e. based on Equation 2.16 in the IPCC AFOLU:

$$\Delta C_{CONVERSION} = \sum_{i} (B_{AFTER_i} - B_{BEFORE_i}) \bullet CF$$

where:

$\Delta C_{CONVERSION}$ = initial change in biomass carbon stocks on land converted to another land category, tonnes C $ha^{-1}$ $yr^{-1}$

$B_{AFTER_i}$ = biomass stocks on land type i immediately after the conversion, tonnes d.m. $ha^{-1}$

$B_{BEFORE_i}$ = biomass stocks on land type I before the conversion, tonnes d.m. $ha^{-1}$

$CF$ = carbon fraction of dry matter, tonne C (tonnes d.m.)$^{-1}$

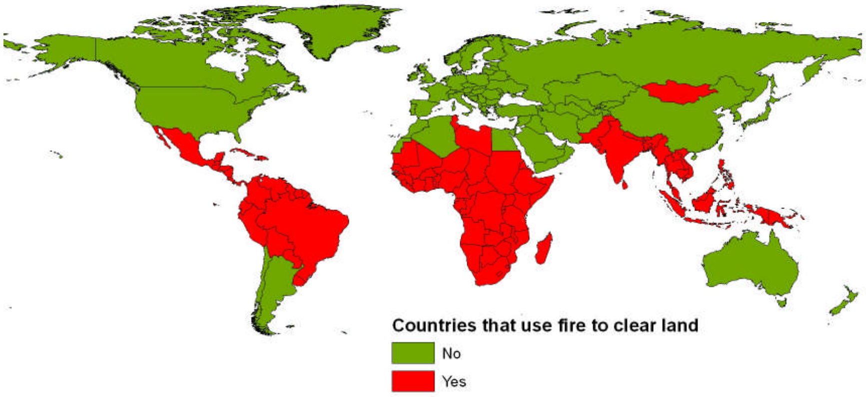
$i$ = type of land use converted to another land-use category

#### 2.4.4.2.6.3 Evaluation of GHG Emissions from International Land Clearing with Fire

In the proposed rule we used expert judgment to determine the regions where land is cleared with fire prior to conversion to crop production. In general, it was assumed that clearing with fire takes place in tropical regions. Several of the expert peer reviewers suggested the use of fire products, such as those derived from MODIS and AVHRR sensors, to determine which regions typically use fire to clear land for another land use. However, the use of these products in isolation would not allow a distinction between fire that occurs for land conversion versus fire that occurs due to wildfires, especially for temperate regions. Therefore, we considered an approach in which various fire maps could be overlain onto land cover change maps to determine fires that occurred on changed pixels (land conversion) versus fires that occurred on pixels that remained in the same land cover category (e.g., forest fire, annual burning of cropland residues, etc.). However, the time needed to do this analysis exceeded the time available. Therefore, we maintained the approach used in the proposed rule analysis, whereby expert judgment was used to determine the regions where fire is commonly used when land is cleared for agricultural production.

Figure 2.4-38 shows the countries where fire is assumed to occur as part of site preparation for crop production.

**Figure 2.4-38. Countries that Clear with Fire in Preparation for Crop Production**



As in the proposed rule analysis, in countries where fire is used commonly as a land clearing practice for conversion to agriculture, non-$CO_2$ emissions were estimated using emission factors in Table 2.5 and Equation 2.27 of the IPCC AFOLU. Fire for land clearing was assumed to occur in all countries included in the analysis except China and Argentina.

Non-$CO_2$ emissions from land clearing with fire were estimated as:

$$L_{fire} = A \bullet M_B \bullet C_f \bullet G_{ef} \bullet 10^{-3}$$

Where:

$L_{fire}$ = amount of greenhouse gas emissions from fire, MT of each GHG (i.e., $CH_4$, $N_2O$)

$A$ = area burnt, ha

$M_B$ = mass of fuel available for combustion, MT $ha^{-1}$.

$C_f$ = combustion factor, dimensionless

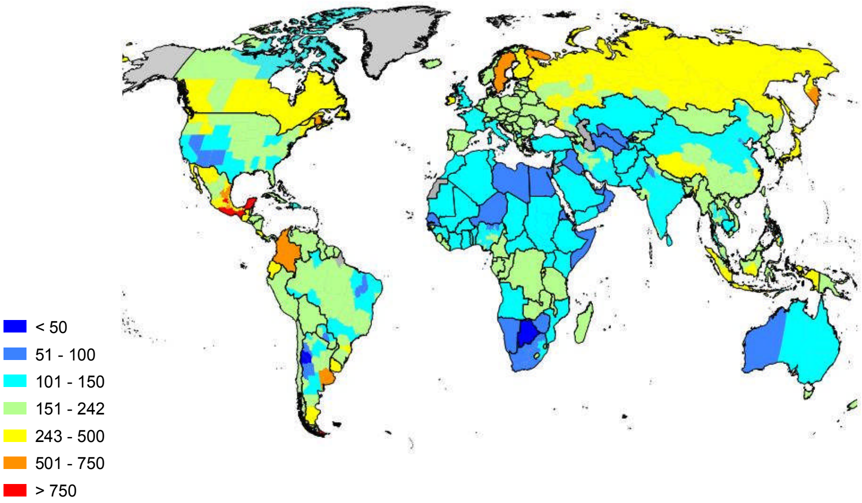
$G_{ef}$ = emission factor, g $kg^{-1}$ dry matter burnt

The mass of fuel available for combustion was conservatively assumed to be equal to the above- and belowground biomass only; dead wood and litter pools were not included in the fuel load estimates. IPCC defaults were used for the forest combustion factor. Values from de Castro and Kaufmann (1998) were used for clearing other land cover types (grassland, savanna, shrubland).

### 2.4.4.2.6.4 Evaluation of International Soil Carbon Stocks

For the initial analysis, soil carbon stocks were estimated using the FAO/UNESCO Soil Map of the World. In March 2009, a new soil database was released (Harmonized Soil Map of the World v.1.1) with 1-km resolution grid cells and therefore this improved dataset was used for the updated analysis.[594] Attribute values of the database did not include average soil carbon stocks, but values were included instead for bulk density (g cm$^{-3}$) and carbon content (%C) in both the top 30 cm and top meter of soil in each grid cell. Therefore, we calculated average soil carbon stocks in the top 30 cm of soil – assumed to be the depth to which soil carbon stocks would be affected when converted to agriculture – by multiplying the volume of soil in a given hectare (1 ha x 30 cm depth = 3,000 m$^3$) by the bulk density to calculate the mass of soil in a given hectare, then multiplied the soil mass by the carbon content to derive an average soil carbon stock value per hectare (t C ha$^{-1}$). Soil carbon stocks estimated per country (and per administrative unit in key countries) are shown in Figure 2.4-39. The soil carbon stocks for annual cropland (i.e., after conversion) are based on long-term cultivated annual cropland with full tillage and medium inputs.

**Figure 2.4-39.**
**Soil carbon stocks in the top 30 cm of soil for each country and administrative unit**
**(t CO2e/ha)**



Note: estimates were derived from the Harmonized World Soil Database v. 1.1

### 2.4.4.2.6.4.1 Evaluation of Changes in Soil Carbon Stocks from International Land Conversions

Identical to the approach used in the proposed rule analysis, changes in soil carbon stocks on land converted to cropland were calculated based on Section 5.3.3.4 of the IPCC AFOLU. Soil carbon stocks after conversion to cropland were based on specific soil stock change factors for land use, management and inputs ($F_{LU}$, $F_{MG}$, $F_I$, respectively) listed in Table 5.10 of the IPCC AFOLU. Stock change factors were selected for each land cover type (before and after conversion) and multiplied by reference soil carbon stocks. Following the IPCC AFOLU guidelines, the total difference in carbon stocks before and after conversion was averaged over 20 years. Thus the average annual change in soil carbon stocks due to land use conversion was calculated as:

$$\Delta SOC = \frac{(SOC_{\mathrm{Re}\,f} \bullet F_{LU,before} \bullet F_{MG,before} \bullet F_{I,before}) - (SOC_{\mathrm{Re}\,f} \bullet F_{LU,after} \bullet F_{MG,after} \bullet F_{I,after})}{20}$$

where:
$\Delta SOC$ = average annual change in carbon stocks in top 30 cm of soil; t C $\mathrm{ha}^{-1}\ \mathrm{yr}^{-1}$
$SOC_{\mathrm{Re}\,f}$ = reference carbon stocks in top 30 cm of soil; t C $\mathrm{ha}^{-1}$
$F_{LU}$ = land use factor before or after conversion
$F_{MG}$ = management factor before or after conversion
$F_{I}$ = input factor before or after conversion

As default values for stock change factors ($F_{LU}$, $F_{MG}$, $F_{I}$) are all one for forest soils and non-degraded grassland soils, soil carbon stocks were assumed to remain unchanged for all conversion types (conversion to shrubland, savanna, perennial cropland) except conversion to cropland. Full tillage and medium inputs were assumed in all scenarios of cropland conversion. Consistent with IPPC default guidelines, soil carbon stock changes were spread equally over 20 years.

###### 2.4.4.2.6.5 Accounting for International Harvested Wood Products

In the updated analysis, we addressed the potential significance of the harvested wood product pool and concluded that the amount of carbon stored in wood products long-term is immaterial for most regions of the world, especially when considering a timeframe of 30 years. Therefore, carbon storage in harvested wood products was not incorporated into our updated emission factors.

We reached this conclusion as follows: the proportion of extracted timber that ends up in long-lived (>5 yr) wood products was estimated using information presented in Winjum et al. (1998), who related harvesting and use of wood products to carbon impacts (Table 2).[595] The proportion of timber volume extracted ending up in long-lived wood products was calculated by dividing carbon in net production of industrial roundwood by the total carbon in commodity uses >5 yr. We did this for the developing and developed world and calculated percentages of 53% and 60%, respectively. The country-level percentages were generally lower than the aggregated values. Winjum et al. (1998) also estimates inherited emissions from the retirement of past wood products, so we also estimated the proportion of roundwood production that is re-emitted into the atmosphere through the retirement of past wood products. These values are reproduced in Table 2.4-42 below.

## Table 2.4-42.

**Calculation of the proportion of extracted timber that goes to long-lived wood products and the proportion of extracted timber as inherited emissions. (Tg C) All units are in Tg C. From Winjum et al. (1998). SWD=sawnwood, WBP=woodbase panels, OIR=other industrial roundwood and P&P=paper and paperboard.**

| Category / Country | Industrial Roundwood Production* | Commodity use ≥ 5 yr[#] | | | | | Inherited emissions | % HWP | % Inherited Emissions |
|---|---|---|---|---|---|---|---|---|---|
| | | SWD | WBP | OIR | P&P | Total | | | |
| Developing | | | | | | | | | |
| Brazil | 23 | 4 | 1 | 1 | 1 | 7 | 4 | 30 | 17 |
| India | 9 | 4 | 0.1 | 1 | 1 | 6 | 3 | 67 | 33 |
| Indonesia | 12 | 2 | 0.1 | 1 | 0.42 | 3 | 1 | 25 | 8 |
| Ivory Coast | 1 | 0.05 | 0.03 | 0.2 | 0.01 | 0.3 | 0.2 | 30 | 20 |
| Developed | | | | | | | | | |
| Canada | 39 | 3 | 1 | 1 | 2 | 7 | 1 | 18 | 3 |
| Finland | 9 | 0.6 | 0.2 | 0.1 | 0.4 | 1.2 | 0.3 | 13 | 3 |
| New Zealand | 2.7 | 0.3 | 0.1 | 0.1 | 0.2 | 0.6 | 0.3 | 22 | 11 |
| U.S.A. | 102 | 23 | 8 | 3 | 23 | 57 | 17 | 56 | 17 |
| Worldwide | | | | | | | | | |
| Developing | 128 | 26 | 6 | 22 | 14 | 68 | 42 | 53 | 33 |
| Developed | 308 | 70 | 27 | 29 | 58 | 184 | 71 | 60 | 23 |
| Total | 436 | 96 | 33 | 51 | 72 | 252 | 113 | 58 | 26 |

* From Table 4 in Winjum et al. (1998).

[#] From Table 5 in Winjum et al. (1998).

Next, we analyzed per-hectare extraction volumes from 111 developing countries using data reported to FAO for the 2005 Forest Resources Assessment. Of the countries analyzed, the country with the highest reported extraction rate was Indonesia (50 $m^3$/ha). This value was much higher compared to countries in Africa and Asia, which weren't much higher than about 20 $m^3$/ha and often less.

For the 50 $m^3$/ha Indonesia case, we converted volume to biomass using an average conversion factor of 0.55 (Table 1 in Winjum et al. 1998, tropical aggregate), then converted biomass to carbon using a conversion factor of 0.5. Therefore, 50 $m^3$/ha of extracted timber translates into 14 t C/ha. Assuming that 25% of this carbon ends up in long-lived (>5 yrs) wood products (i.e., the value calculated in Table 3 above for Indonesia), the emission factor estimated for forest conversion after taking into account carbon storage in wood products would be reduced only by 3 t C $ha^{-1}$, or 11 t $CO_2$ $ha^{-1}$, or approximately 1-2%.

This result of 11 t $CO_2$/ha stored in wood products from Indonesian harvests longer than five years is an overestimate. The calculation assumes that the carbon that ends up in these wood products is stored forever. After taking into account the inherited emissions that emanate from the oxidation (i.e., burning and decay) of wood products that were produced from harvests during previous years (retirement rate, see Table 3), the Indonesia value of carbon stored in wood products decreases even further to 2 t C/ha, or 7 t $CO_2$e/ha.

Finally, Winjum et al. (1998) states that for the oxidation fractions of 0.04, 0.08 and 0.10 (representing rates for woodbase panels, other industrial roundwood and paper/paperboard), the time period of oxidation would extend back 25, 12 and 10 yr from the base year, respectively, for tropical regions. Therefore, much of the timber harvested today and stored as wood products will be completely oxidized 25 years from now. Considering EPA is estimating 30-year emission factors, carbon storage in wood products is likely insignificant, even for temperate and boreal regions where oxidation rates are slower. The analysis outlined above is also representative of productive forestlands only, and it is unlikely that every hectare of forest that is cleared for another land use is stocked for timber production.

As discussed in preamble Section V, modeling the fate of international harvested wood products is an area for future work and consideration of more data. For example, Pingoud et al. (2001)[596] and Micales and Skog (1997)[597] estimate longer average lifetimes for wood products than the assumptions used in our analysis. However, based on our research discussed above, we believe it is very likely that carbon sequestration from harvested wood products is captured in our estimated uncertainty ranges.

#### 2.4.4.2.6.6 Evaluation of International Foregone Forest Sequestration

Forest sequestration rates were estimated in the proposed rule analysis using IPCC Tier 1 default values for native forests. These values are listed by ecological zone, so final rates in the initial analysis were calculated by weighting the ecological zone-based sequestration rates by the proportion of forest area in each ecological zone within a country or administrative unit (for key countries). The expert peer reviewers pointed out a number of recent papers that summarize long-term monitoring plots in old growth tropical forests across the tropics and suggested the use of these more recent datasets for estimating annual rates of carbon sequestration in tropical forests.

Lewis et al. (2009) published long-term aboveground carbon sequestration rates of 0.63 t C/ha/yr for African “closed canopy mature forests” (assumed moist or rain forest) based on long-term monitoring plots.[598] This is similar to the IPCC default rate for >20 yr old African tropical moist deciduous forests (0.65 t C/ha/yr) but lower than for >20 yr old African tropical rain forests (1.55 t C/ha/yr). Baker et al. (2004) also report an annual Amazonian C sequestration rate of 0.61 t C $ha^{-1}$ $yr^{-1}$, which is lower than the IPCC default of 1.0 t C ha/yr for >20 yr old tropical moist deciduous forests and 1.55 t C/ha/yr for >20 yr old tropical rain forests of South America. After combining all standardized inventory data from Africa, tropical America and Asia together, Lewis et al. (2009) estimate carbon sequestration across all tropical intact old growth forests as 0.49 t C/ha/yr. We have used this estimate for foregone sequestration across the tropics in our updated analysis.

Myneni et al. (2001) and Nabuurs et al. also estimated the carbon sink of temperate and boreal forests in various countries, and these values were generally higher than sequestration in tropical forests, with rates of approximately 3-4 t $CO_2$e/ha/yr on average but extending up to 7-8 t $CO_2$e/ha/yr in Norway and Switzerland. These data reflect the long-term carbon sink capacity of forests, which have long been understood to be the case in temperate forests and have more recently been illustrated for old-growth tropical forests as well.

#### 2.4.4.2.6.7 Evaluation of International Land Reversion Carbon Uptake Factors

In addition to estimating emission factors, reversion factors were developed to estimate the carbon accumulation in biomass and soils that occurs when managed cropland and pasture land is abandoned. All reversion factors (except reversion to forest) were estimated as the reverse of emission factors, whereby all increases in biomass carbon stocks occur in Year 1 (analogous to the stock change approach used to estimate emission factors) while changes in soil carbon stocks on abandoned cropland recovers to pre-land use change levels in 20 years (analogous to the soil emission factors, which were assumed to emit over 20 years). The only reversion factor to include soil carbon accumulation was reversion from abandoned cropland.

While most reversion factors assumed that all biomass carbon stock changes occurred in Year 1 (i.e., IPCC stock change approach), forest reversion factors assumed that biomass accumulates every year over the entire 30-year time period. This was done to reflect forests' slow but continual carbon sink capacity. Despite the fact that young (<20 year old) forests accumulate biomass more quickly than older (>20 year old) forests, the annual rate of carbon accumulation on abandoned croplands that revert back to forests was conservatively assumed to be equal to the foregone forest sequestration rate (estimated for the emission factor analysis). If the forest biomass carbon stock (estimated for the emission factor analysis, see Figure 4 above) was less than 20 times the assumed annual foregone carbon sequestration value, then the annual carbon sequestration rate for reversion factors was assumed to be 1/20th of the initial forest carbon stock. Both of these assumptions provide a very conservative estimation of the carbon accumulation that occurs on abandoned land when it reverts to forest.

#### 2.4.4.2.6.8 International Land Conversion GHG Emissions Factor Results

Our updated analysis includes land use change emissions factors for up to 42 different land conversions in over 750 regions across 160 countries, i.e. over 30,000 land conversion emissions factors. In this section we use the example of the Amazon region in Brazil to illustrate the emissions factors used in our analysis. The sample results shown below cover all of the types of land conversions considered, but they do not cover all of the 750+ regions. For all of the emissions factors used in our analysis, including the data inputs, refer to the results spreadsheets available on the public docket.

The FAPRI-CARD model simulates agricultural production in 6 regions in Brazil, including the Amazon Biome. The Amazon Biome region in FAPRI-CARD includes the following Administrative Units: Acre, Amapa, Amazonas, Para, Rondonia, Roraima, and the northern part of Mato Grosso which is characterized by forest biome land cover. Figure 2.4-40 illustrates the segment of Mato Grosso included in the Amazon region). The carbon stock data inputs for the Amazon region are shown in Table 2.4-43.

**Figure 2.4-40. Division of Mato Grosso into North and South regions**

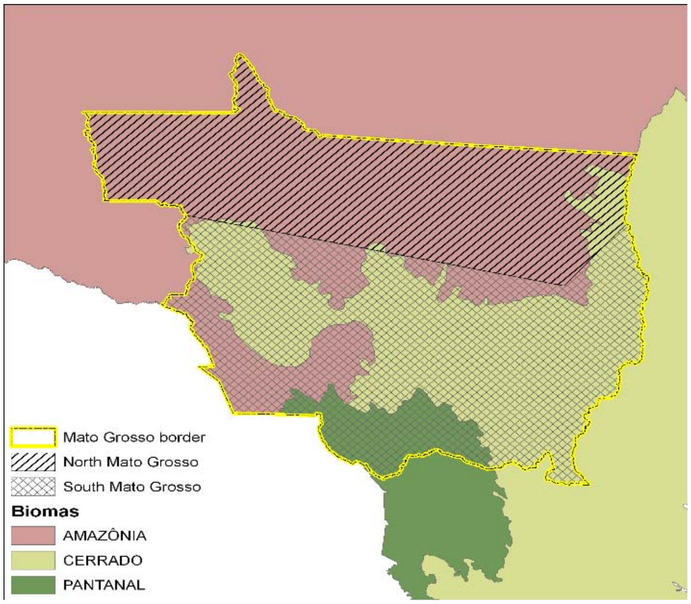


**Table 2.4-43. Carbon stocks by land type and Administrative Unit in the Amazon Region (t CO2e/ha)**

| | *Administrative Units* | | | | | | |
|---|---|---|---|---|---|---|---|
| | Acre | Amapa | Amazonas | North Mato Grosso | Para | Rondonia | Roraima |
| Forest, Above Ground | 585 | 425 | 477 | 453 | 457 | 481 | 487 |
| Forest, Below Ground | 150 | 112 | 125 | 119 | 120 | 125 | 127 |
| Grassland | 40 | 40 | 40 | 40 | 40 | 40 | 40 |
| Savanna | 72 | 72 | 72 | 72 | 72 | 72 | 72 |
| Shrubland | 137 | 137 | 137 | 137 | 137 | 137 | 137 |
| Mixed | 232 | 183 | 199 | 192 | 193 | 200 | 202 |
| Wetland | 88 | 88 | 88 | 88 | 88 | 88 | 88 |
| Annual | 18 | 18 | 18 | 18 | 18 | 18 | 18 |
| Perennial | 44 | 44 | 44 | 44 | 44 | 44 | 44 |
| Soil | 131 | 154 | 231 | 213 | 174 | 115 | 145 |
| Soil, Annual | 63 | 74 | 111 | 102 | 84 | 55 | 70 |

We assume that land converted to cropland in the Amazon will be cleared with fire. Therefore, to determine non-CO2 emissions from fire in the Amazon we used the fire combustion data inputs in Table 2.4-44 where the data inputs are the same for all of the Administrative Units.

**Table 2.4-44.**
**Data inputs for non-CO2 emissions in the Amazon by land type**

| Land Cover | Fire combustion factors (dimensionless) | Fire $CH_4$ emission factors (g/kg) | Fire $N_2O$ emission factors (g/kg) |
|---|---|---|---|
| Forest | 0.46 | 6.80 | 0.20 |
| Grass | 0.76 | 2.30 | 0.21 |
| Shrub | 0.72 | 2.30 | 0.21 |
| Savanna | 0.57 | 2.30 | 0.21 |
| Wetland | 0.70 | 2.30 | 0.21 |
| Mixed | 0.64 | 3.80 | 0.21 |

To show emissions estimates for all of the land conversions considered in our analysis, we will focus on the North Mato Grosso, i.e. the portion of Mato Grosso in the Amazon region. Table 2.4-45 shows land use change GHG emissions, broken out by emissions category, for crop and pasture expansion in this region. We show emissions for conversion of land cover to annual cropland and perennial cropland. We also show emissions for conversion to pasture, which can be in the form of grassland or savanna. The values are presented as total GHG emissions, or, where specified, as annual emissions (yr-1). Note that negative values signify carbon uptake, whereas positive values denote GHG releases.

We also present the emissions results over time. For accounting purposes, emissions are allocated to either year zero (i.e., the year when land clearing takes place), years 1-19 or to years 20-80. This procedure is not intended to be a precise accounting of the timing of emissions releases, but it is sufficient to determine total emissions over the first 30 years following land conversion. Carbon emissions from the changes in biomass resulting from land conversion (i.e., biomass combustion or decay) are assigned to year zero. Non-CO2 emissions from fire combustion are also allocated to year zero. Lost forest sequestration continues indefinitely. The change in soil carbon is spread evenly over the first twenty years following conversion, i.e. ending in year 19. Thus, total emissions are presented for year zero, years 1 through 19, and years 20-80. We also present the total emissions over 30 years.

### Table 2.4-45. Land use change emissions factors for North Mato Grosso, Brazil (t CO2e/ha)

| Start | End | Change in biomass | Lost forest seques. yr-1 | Change in soil yr-1 | Total fire emis. | Yr 0 emis. | Yrs 1-19 emis. Yr-1 | Yrs 20-80 emis. yr-1 | 30-yr emis. |
|---|---|---|---|---|---|---|---|---|---|
| Forest | Annual | 553.78 | 1.80 | 5.53 | 53.31 | 614.42 | 7.33 | 1.80 | 771.62 |
| Shrub | Annual | 118.43 | 0.00 | 5.53 | 11.17 | 135.13 | 5.53 | 0.00 | 240.22 |
| Savanna | Annual | 53.90 | 0.00 | 5.53 | 4.67 | 64.10 | 5.53 | 0.00 | 169.19 |
| Grass | Annual | 21.63 | 0.00 | 5.53 | 3.42 | 30.59 | 5.53 | 0.00 | 135.68 |
| Wetland | Annual | 70.03 | 0.00 | 5.53 | 7.01 | 82.58 | 5.53 | 0.00 | 187.67 |
| Mixed | Annual | 173.46 | 0.00 | 5.53 | 17.88 | 196.87 | 5.53 | 0.00 | 301.96 |
| Forest | Perennial | 528.12 | 1.80 | 0.00 | 0.00 | 529.91 | 1.80 | 1.80 | 582.02 |
| Shrub | Perennial | 92.77 | 0.00 | 0.00 | 0.00 | 92.77 | 0.00 | 0.00 | 92.77 |
| Savanna | Perennial | 28.23 | 0.00 | 0.00 | 0.00 | 28.23 | 0.00 | 0.00 | 28.23 |
| Grass | Perennial | -4.03 | 0.00 | 0.00 | 0.00 | -4.03 | 0.00 | 0.00 | -4.03 |
| Wetland | Perennial | 44.37 | 0.00 | 0.00 | 0.00 | 44.37 | 0.00 | 0.00 | 44.37 |
| Mixed | Perennial Crop | 147.80 | 0.00 | 0.00 | 0.00 | 147.80 | 0.00 | 0.00 | 147.80 |
| Forest | Grass | 532.15 | 1.80 | 0.00 | 0.00 | 533.95 | 1.80 | 1.80 | 586.05 |
| Shrub | Grass | 96.80 | 0.00 | 0.00 | 0.00 | 96.80 | 0.00 | 0.00 | 96.80 |
| Mixed | Grass | 151.83 | 0.00 | 0.00 | 0.00 | 151.83 | 0.00 | 0.00 | 151.83 |
| Forest | Savanna | 499.88 | 1.80 | 0.00 | 0.00 | 501.68 | 1.80 | 1.80 | 553.78 |
| Shrub | Savanna | 64.53 | 0.00 | 0.00 | 0.00 | 64.53 | 0.00 | 0.00 | 64.53 |
| Mixed | Savanna | 119.56 | 0.00 | 0.00 | 0.00 | 119.56 | 0.00 | 0.00 | 119.56 |

Note: "Annual" refers to annual crops, and "Perennial" refers to perennial crops, i.e., sugarcane.

Table 2.4-46 is similar to the preceding table, except that emissions factors are shown for crop and pasture abandonment, i.e. land reversion. For land reverting to forest, the change in biomass (i.e. plant growth) is an annual factor that continues for twenty years. After twenty years forests grow at the foregone sequestration rate, which is 1.80 tCO$_2$e /ha/yr in the Amazon region. For land reverting to any other land type, the change in biomass is a total uptake that is allocated fully to year zero. That is why year zero uptake in Table 2.4-46 is larger for reversion to shrubland than to forest, but the total forest uptake over thirty years is larger than reversion to shrubland. These time accounting procedures were designed to provide accurate estimates of emissions over 30 years. Soil carbon uptake is an annual factor that is constant for the first twenty years following conversion.

**Table 2.4-46.**
**Land reversion factors for North Mato Grosso, Brazil (t CO2e/ha)**

| Start | End | Change in biomass | Soil seques. yr-1 | Yr 0 uptake | Yr 1-19 uptake yr-1 | Yr 20-80 uptake yr-1 | 30-yr uptake |
|---|---|---|---|---|---|---|---|
| Annual | Forest | -25.93 | -5.53 | -31.46 | -31.46 | -1.80 | -647.18 |
| Annual | Shrub | -118.43 | -5.53 | -123.96 | -5.53 | 0.00 | -229.05 |
| Annual | Savanna | -53.90 | -5.53 | -59.43 | -5.53 | 0.00 | -164.52 |
| Annual | Grass | -21.63 | -5.53 | -27.16 | -5.53 | 0.00 | -132.25 |
| Annual | Mixed | -173.46 | -5.53 | -178.99 | -5.53 | 0.00 | -284.08 |
| Perennial | Forest | -25.93 | 0.00 | -25.93 | -25.93 | -1.80 | -536.56 |
| Perennial | Shrub | -92.77 | 0.00 | -92.77 | 0.00 | 0.00 | -92.77 |
| Perennial | Savanna | -28.23 | 0.00 | -28.23 | 0.00 | 0.00 | -28.23 |
| Perennial | Grass | 4.03 | 0.00 | 4.03 | 0.00 | 0.00 | 4.03 |
| Perennial | Mixed | -147.80 | 0.00 | -147.80 | 0.00 | 0.00 | -147.80 |
| Grass | Forest | -25.93 | 0.00 | -25.93 | -25.93 | -1.80 | -536.56 |
| Grass | Shrub | -96.80 | 0.00 | -96.80 | 0.00 | 0.00 | -96.80 |
| Grass | Mixed | -151.83 | 0.00 | -151.83 | 0.00 | 0.00 | -151.83 |
| Savanna | Forest | -25.93 | 0.00 | -25.93 | -25.93 | -1.80 | -536.56 |
| Savanna | Shrub | -64.53 | 0.00 | -64.53 | 0.00 | 0.00 | -64.53 |
| Savanna | Mixed | -119.56 | 0.00 | -119.56 | 0.00 | 0.00 | -119.56 |

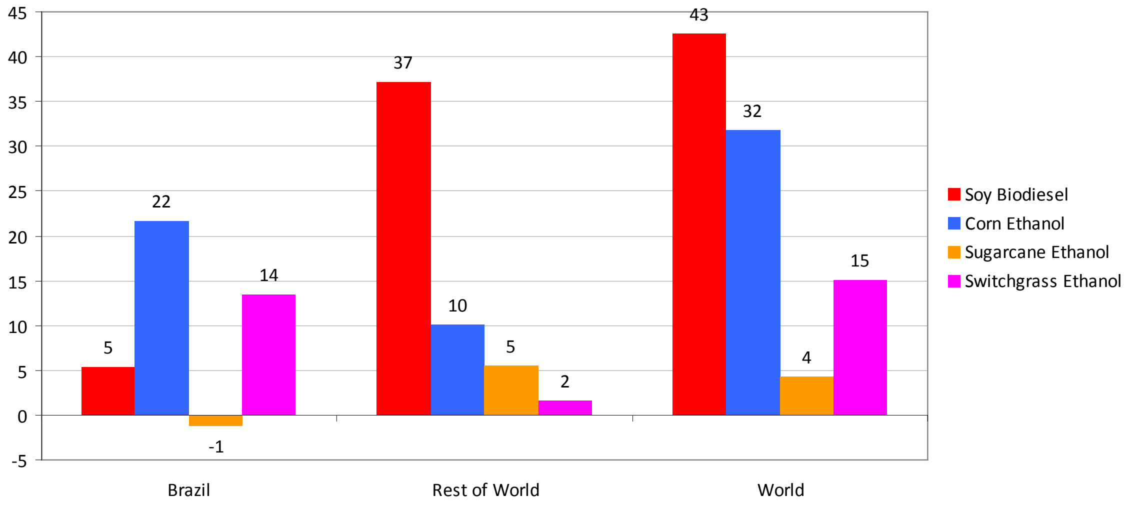
Note: "Annual" refers to annual crops, and "Perennial" refers to perennial crops, i.e., sugarcane.

All of the data and calculations for the results presented above for the Amazon region, and for all of the 750+ regions analyzed, are available in supporting material on the public docket for this rulemaking.

#### 2.4.4.2.7 Aggregate International Land Conversion GHG Emissions Impact Results

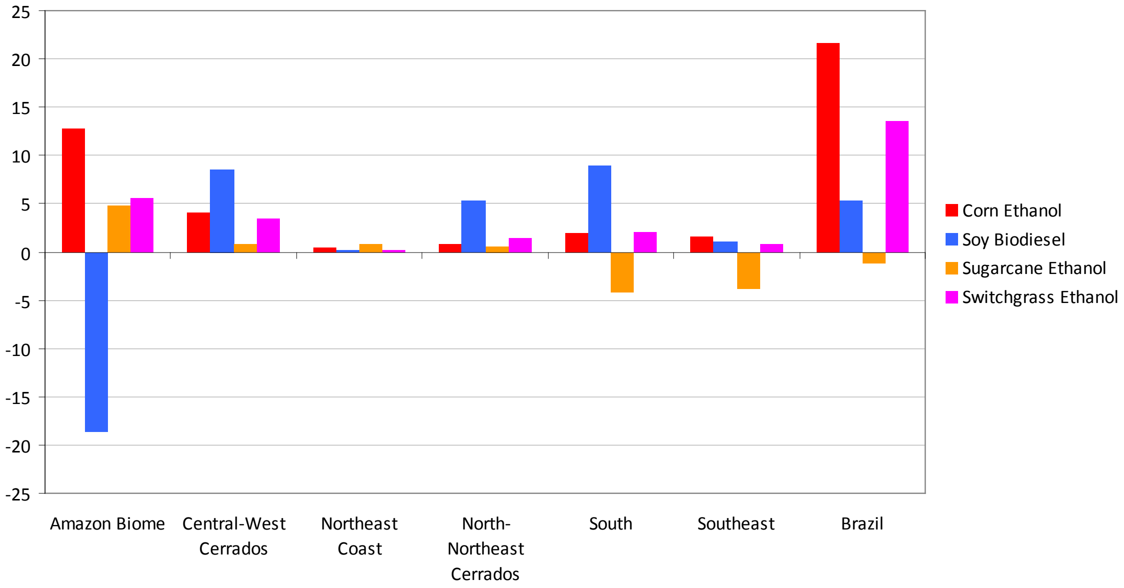
Figure 2.4-41presents the 2022 international land use change GHG emissions by renewable fuel, with land use change emissions normalized by the increment of additional biofuel produced in each scenario and annualized over 30 years. The figure shows that, based on our modeling, soy-based biodiesel causes the largest release of international land use change GHG emissions. The majority of international land use change emissions originate in Brazil in the corn ethanol and switchgrass ethanol scenarios. This is largely a consequence of projected pasture expansion in Brazil, and especially in the Amazon region where land clearing causes substantial GHG emissions. Of the renewable fuels analyzed, our modeling found that sugarcane ethanol causes the least amount of land use change emissions. This was due largely to our projection that sugarcane crops would expand onto grasslands in South and Southeast Brazil, which results in a net sequestration because sugarcane sequesters more biomass carbon than the grasslands it would replace.

**Figure 2.4-41. International land use change GHG emissions by renewable fuel, 2022 (kgCO2e/mmBTU)**



Brazil is a very prominent region in our projections of where biofuel-induced land use changes would occur. Figure 2.4-42 shows the land use change emissions across the 6 regions of Brazil included in the FAPRI-CARD model. All of the renewable fuels analyzed, except for soy-based biodiesel, cause land use change emissions in the Amazon region. In the soy biodiesel scenario we project net sequestration in the Amazon as a result of reduced pasture area in that region. As discussed above, sugarcane ethanol results in net sequestrations in South and Southeast Brazil.

## Figure 2.4-42. Brazil land use change GHG emissions by renewable fuel, 2022 (kgCO2e/mmBTU)



Finally, for reference, Table 2.4-47 presents same results broken out by all 54 international regions in the FAPRI-CARD model.

## Table 2.4-47.
## International land use change GHG emissions by renewable fuel and by region, 2022 (kgCO2e/mmBTU)

| FAPRI-CARD Region | Corn Ethanol | Soy Biodiesel | Sugarcane Ethanol | Switchgrass Ethanol |
|---|---|---|---|---|
| Algeria | 0.02 | 0.02 | 0.01 | 0.01 |
| Argentina | -0.31 | 0.11 | -0.52 | 0.15 |
| Australia | 0.52 | 0.00 | 0.00 | 0.18 |
| Bangladesh | -0.43 | -0.56 | -0.12 | 0.10 |
| Brazil: Amazon Biome | 12.83 | -18.63 | 4.79 | 5.57 |
| Brazil: Central-West Cerrados | 4.09 | 8.52 | 0.76 | 3.47 |
| Brazil: Northeast Coast | 0.41 | 0.14 | 0.77 | 0.14 |
| Brazil: North-Northeast Cerrados | 0.86 | 5.33 | 0.52 | 1.47 |
| Brazil: South | 1.93 | 8.95 | -4.20 | 2.08 |
| Brazil: Southeast | 1.56 | 1.00 | -3.81 | 0.80 |
| Canada | -0.04 | 0.73 | -0.11 | 0.08 |
| China | 0.56 | 4.54 | -0.03 | 0.46 |
| New Zealand | 0.05 | 0.60 | 0.01 | 0.03 |
| Colombia | 0.25 | 1.98 | 0.25 | 0.15 |
| Cuba | 0.05 | 0.10 | 0.14 | 0.01 |
| Egypt | -0.01 | 0.00 | 0.00 | 0.00 |
| EU | 0.47 | 1.68 | 0.30 | 0.29 |
| Guatemala | 0.22 | 0.17 | 0.11 | 0.06 |
| India | 0.84 | 2.30 | 0.47 | -2.14 |
| Indonesia | 3.34 | 4.07 | 1.13 | -0.13 |
| Iran | 0.09 | 0.22 | 0.05 | 0.06 |
| Iraq | 0.01 | 0.04 | 0.01 | 0.01 |
| Ivory Coast | 0.07 | 0.33 | 0.09 | 0.13 |
| Japan | 1.22 | 0.07 | 0.02 | -0.74 |
| Malaysia | -0.11 | 2.98 | 0.03 | 0.04 |
| Mexico | 1.01 | 2.25 | 0.11 | 0.06 |
| Morocco | 0.04 | 0.05 | 0.02 | 0.03 |

| FAPRI-CARD Region | Corn Ethanol | Soy Biodiesel | Sugarcane Ethanol | Switchgrass Ethanol |
|---|---|---|---|---|
| Myanmar (Burma) | -0.06 | 0.14 | 0.01 | -0.01 |
| Nigeria | 0.76 | 0.58 | 0.19 | 0.32 |
| Africa, Other | 1.13 | 3.87 | 0.43 | 0.61 |
| Asia, Other | 0.12 | 0.34 | 0.00 | -0.09 |
| CIS, Other | -1.50 | -0.70 | -0.13 | -0.05 |
| Eastern Europe, Other | 0.02 | 0.14 | 0.02 | 0.03 |
| Latin America, Other | 0.49 | 2.27 | 0.26 | 0.21 |
| Middle East, Other | 0.00 | 0.05 | 0.01 | 0.02 |
| Pakistan | -0.07 | 0.39 | 0.06 | 0.14 |
| Paraguay | 0.03 | -0.52 | 0.17 | 0.26 |
| Peru | -0.56 | 1.88 | 0.08 | 0.09 |
| Philippines | 1.25 | 1.26 | 0.51 | 0.34 |
| Rest of World | 1.04 | 2.73 | 0.32 | 0.29 |
| Russia | 0.01 | 0.31 | 0.09 | 0.12 |
| South Africa | 0.04 | 0.58 | 0.05 | 0.05 |
| South Korea | 0.00 | 0.02 | 0.00 | 0.01 |
| Taiwan | 0.00 | 0.04 | 0.00 | 0.00 |
| Thailand | 0.22 | 0.40 | 0.15 | 0.16 |
| Tunisia | 0.02 | 0.05 | 0.01 | 0.02 |
| Turkey | -0.10 | 0.11 | 0.03 | 0.02 |
| Ukraine | -0.13 | 0.18 | 0.01 | 0.02 |
| Uruguay | -0.03 | 0.37 | 0.03 | 0.05 |
| United States* | | | 1.05 | |
| Uzbekistan | -0.47 | -0.29 | -0.06 | -0.05 |
| Venezuela | -0.21 | 1.14 | 0.05 | 0.02 |
| Vietnam | 0.23 | 0.15 | 0.11 | 0.07 |
| Western Africa | 0.03 | 0.09 | 0.04 | 0.08 |
| **TOTAL** | **31.79** | **42.54** | **4.30** | **15.07** |

Note: land use change emissions in the United States were calculated by the FASOM model (see discussion above about domestic land use change), except for in the sugarcane ethanol scenario.

### 2.4.4.2.8 Uncertainty Assessment for International Land Conversion GHG Emissions Impacts

For the proposed RFS rule, EPA estimated uncertainty around its lifecycle GHG emission estimates by sensitivity analyses by which, for example, the upper bound of the emissions from international land use change was estimated by assuming that all crop expansion came from forest and the lower bound was estimated by assuming that all expansion came from idle grassland (also by assuming that no pasture replacement is necessary). For its updated analysis, we took a more rigorous approach towards estimating uncertainty.

Uncertainty can be expressed as a percentage confidence interval relative to a mean value, with the confidence interval defined as a range that encloses the true value of an unknown parameter with a specified probability. For example, if the area of forest land converted to cropland (mean value) is 100 ha, with a 95% confidence interval ranging from 90 to 110 ha, we can say that the uncertainty around the estimate is ±10%.

The 95% confidence interval, which is the value typically used in the context of estimating GHG emissions and removals under the United Nations Framework Convention on Climate Change (UNFCCC), has a 95 percent probability of enclosing the true but unknown value of a given parameter.

The first step in our uncertainty analysis was to identify the potential sources of uncertainty. We focused on two key sources of uncertainty in international land use change GHG emissions:

(1) Classification errors that arise from interpretation of satellite imagery to derive land cover maps (i.e., the types of land affected by land use change);
(2) Errors in parameters used in emission factor estimates (i.e., the magnitude of GHG emissions per unit of land area converted).

When estimating the total uncertainty in land use change GHG emissions, the two sources of uncertainty listed above need to be considered together, which was done with a Monte Carlo simulation model that combined the total uncertainty in the satellite imagery and the emissions factor estimates. Each step of our uncertainty analysis is explained in this section.

#### 2.4.4.2.8.1 Satellite Data Uncertainty Assessment

As discussed above, MODIS validation data was used to adjust/correct systematic errors in the MODIS land cover classifications from 2001 to 2007. These adjustments were based on the producer's accuracies for each land cover class derived from the aggregated confusion matrix (see Table 2.4-37 above). To estimate the uncertainty in this procedure, we calculated the producer's accuracy standard errors for each land category based on the number of training sites that were used to validate the satellite classifications. For example, based on the number of training sites that validated forest land, we calculated a standard error of +/- 1.2% around the 92.6% producer's accuracy for forest. The most accurate approach to estimate the standard errors from the aggregated confusion matrix would be to reassign the detailed site and pixel data and then recalculate the standard error following Stehman (1997).[599] However, detailed data about the training site clusters were not available, so a simplification of this procedure was used where we assumed that the number of pixels per site (or cluster) was constant for each producer land use, essentially representing the random variable for the producer's accuracy estimate as a binomial distribution:[LLLLLLL]

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[LLLLLLL] Our simplified procedures very closely reproduced the producer accuracy standard errors reported in Friedl et al. (2010).

- We assumed that the number of pixels per site for the reported land use is constant.
- The number of reported sites in each land category was then estimated by using the producer’s accuracy estimate, sometimes referred to as the producer’s estimate, and the producer’s standard error using the following equation derived from the equation for the standard deviation for a binomial distribution:
  - N = e * (1-e)/(s+a)2
  - where,
    - ☐ **N** is the number of sites
    - ☐ **e** is the producer’s estimate
    - ☐ **s** is the producer’s standard error reported as a percentage of the number of sites
    - ☐ **a** is an adjustment factor (-0.0007397) used to account for round off and so the total number of sites estimated approximates the total number of sites report by the input source[MMMMMMM]
  - This equation is derived by assuming that the assignment of sites to land categories is a binomial process (either assigned to the actual land category or not) which has a standard deviation of (s+a)*N = (N *e*(1-e))0.5
- The number of sites for the 17 land categories were then aggregated to the 10 EPA land uses
- The standard error as a percentage of the total number of reported sites for the 10 EPA land uses was then calculated using the equations = (N*e*(1-e))^0.5/N

The producer’s accuracy and standard errors were reduced significantly by aggregating the MODIS data from 17 land cover categories to 10 categories. As an example, the standard error for forest estimated with 17 land categories land was high because there were less training sites for each type of forest, and the producer estimate for each forest type was low because different types of forest were confused with each other. Table 2.4-48 compares the producer’s accuracy and standard errors for the 17 IGBP land categories to the producer’s accuracies and standard errors for EPA’s aggregated land cover classes.

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[MMMMMMM] This equation is derived from the equation from the standard deviation for a binomial distribution.

### Table 2.4-48. Producer accuracies and standard errors for MODIS Collection 5 classes and EPA classes based on cross-validation

| IGBP Land Cover Class | Producer's accuracy (%) | | EPA Land Cover Class | Producer's accuracy (%) | |
|---|---|---|---|---|---|
| | PA | Std. err. | | PA | Std. err. |
| Evergreen Needleleaf | 89.8 | 2.3 | Forest | 92.6 | 1.2 |
| Evergreen Broadleaf | 92.6 | 2.4 | | | |
| Deciduous Needleleaf | 67.3 | 10.9 | | | |
| Deciduous Broadleaf | 68.9 | 6.2 | | | |
| Mixed Forest | 76.2 | 5.7 | | | |
| Closed Shrubland | 63.4 | 5.9 | Shrubland | 69.5 | 4.0 |
| Open Shrubland | 48.3 | 6.2 | | | |
| Woody Savanna | 45.2 | 4.1 | Savanna | 60.9 | 3.1 |
| Savanna | 22.6 | 4.4 | | | |
| Grasslands | 73.6 | 4.1 | Grasslands | 73.7 | 4.0 |
| Permanent Wetlands | 70.6 | 4.2 | Wetlands | 70.6 | 4.1 |
| | | | Annual Crops | 83.2 | 2.7 |
| Cropland | 83.3 | 2.0 | Perennial Crops | 83.2 | 8.6 |
| Cropland/Nat Veg Mosaic | 60.5 | 5.7 | Mixed | 60.4 | 5.6 |
| Barren/Sparse | 95.8 | 1.4 | Barren | 95.8 | 1.3 |
| Snow and Ice | 75.6 | 10.9 | Excluded | 90.5 | 2.7 |
| Water | 96.6 | 1.9 | | | |

The MODIS data was adjusted/corrected based on the producer accuracies reported above, i.e., with the producer standard errors set to zero. To assess the uncertainty in our correction process, and thus the MODIS data, we simulated the uncertainty in the producer's accuracy by generating 10 pseudo random values each for 2001 and for 2007 (RVpy), for each of the land uses. The pseudo random values are distributed normally with a mean of zero and a standard deviation equal to the calculated producer standard error. The stochastic model uses these to adjust the reported land use in the confusion matrix and create an adjusted confusion matrix, BCM, with coefficients BCMcyup as follows:

- BCMcypp = ACMcpp * (1+RVpy)
- Scale the remaining coefficients in the column so that the total of the column does not change
  - ☐ BCMcyup = ACMcup * β
  - ☐ Where β = (1-BCMcypp)/(1-ACMcpp) when ACMcpp < 1 and 0 otherwise
- For every iteration, we repeated the steps listed above in Section 2.4.4.2.5.2 to calculate the land conversion shares in each region.

We repeated this stochastic procedure 300 times to generate the 95% confidence intervals for the share of land conversion types in each of the 54 FAPRI-CARD regions.

## Table 2.4-49

## 30-Year Emissions Factor Satellite Data Uncertainty for Select Land Conversions (+/- 95% confidence intervals as percent of mean)

| FAPRI-CARD Region | Natural to Annual | Annual to Natural | Natural to Pasture | Pasture to Natural |
|---|---:|---:|---:|---:|
| Algeria | 12% | 1% | 16% | 7% |
| Argentina | 1% | 1% | 5% | 4% |
| Australia | 3% | 1% | 6% | 3% |
| Bangladesh | 2% | 1% | 9% | 5% |
| Brazil: Amazon Biome | 6% | 1% | 8% | 1% |
| Brazil: Central-West Cerrados | 2% | 1% | 5% | 3% |
| Brazil: Northeast Coast | 1% | 1% | 4% | 5% |
| Brazil: North-Northeast Cerrados | 2% | 1% | 5% | 4% |
| Brazil: South | 1% | 1% | 6% | 3% |
| Brazil: Southeast | 1% | 1% | 5% | 3% |
| Canada | 5% | 1% | 11% | 2% |
| China | 2% | 1% | 5% | 3% |
| New Zealand | 3% | 1% | 5% | 1% |
| Colombia | 7% | 1% | 17% | 1% |
| Cuba | 3% | 1% | 8% | 2% |
| Egypt | 25% | 6% | 19% | 14% |
| EU | 4% | 1% | 11% | 2% |
| Guatemala | 3% | 1% | 6% | 2% |
| India | 2% | 2% | 4% | 4% |
| Indonesia | 2% | 1% | 4% | 2% |
| Iran | 3% | 1% | 5% | 2% |
| Iraq | 2% | 3% | 3% | 4% |
| Ivory Coast | 3% | 1% | 5% | 2% |
| Japan | 10% | 1% | 29% | 1% |
| Malaysia | 2% | 2% | 3% | 2% |
| Mexico | 1% | 1% | 4% | 2% |
| Morocco | 3% | 1% | 8% | 4% |
| Myanmar | 3% | 1% | 6% | 2% |
| Nigeria | 2% | 1% | 5% | 3% |
| Other Africa | 2% | 2% | 7% | 4% |
| Other Asia | 3% | 1% | 6% | 2% |
| Other CIS | 6% | 1% | 10% | 2% |
| Other Eastern Europe | 3% | 1% | 9% | 2% |
| Other Latin America | 5% | 1% | 11% | 2% |
| Other Middle East | 12% | 3% | 13% | 5% |
| Pakistan | 3% | 1% | 5% | 3% |
| Paraguay | 2% | 1% | 6% | 2% |
| Peru | 9% | 1% | 13% | 1% |
| Philippines | 2% | 1% | 4% | 2% |
| Rest of World | 5% | 3% | 8% | 4% |
| Russia | 3% | 1% | 9% | 2% |
| South Africa | 2% | 1% | 6% | 3% |
| South Korea | 2% | 1% | 7% | 2% |
| Taiwan | 3% | 1% | 6% | 2% |
| Thailand | 2% | 1% | 4% | 2% |
| Tunisia | 3% | 1% | 8% | 4% |
| Turkey | 5% | 1% | 15% | 4% |
| Ukraine | 10% | 2% | 31% | 4% |
| Uruguay | 0% | 1% | 5% | 6% |
| US | 4% | 1% | 7% | 2% |
| Uzbekistan | 11% | 2% | 15% | 4% |
| Venezuela | 5% | 1% | 15% | 2% |
| Vietnam | 2% | 1% | 3% | 2% |
| Western Africa | 1% | 1% | 5% | 5% |

Table 2.4-49 reports relatively modest levels of uncertainty from the MODIS data. There are several potential explanations for this. First, by correcting for systematic errors in the MODIS data, based on NASA's extensive validation efforts, the uncertainty in the satellite data set is reduced substantially. Second, the aggregated land classes in our analysis reduced the uncertainty compared to the 17 MODIS land cover classes. Third, the greatest uncertainty in the satellite data is between land cover classes that sequester similar amounts of carbon (i.e., savanna, shrubland and mixed land). Finally, we assume that recent land use change patterns accurately predict future patterns, and our uncertainty assessment does not quantify the potential uncertainty from this assumption.

The overall uncertainty in our land use change GHG emissions estimates also includes the uncertainty in the emissions factors per unit area of land use change. Before the final uncertainty estimates are presented, our evaluation of emissions factor uncertainty is discussed in the next section.

###### 2.4.4.2.8.2 International Land Conversions GHG Emissions Factor Uncertainty Assessment

We assessed the uncertainties in our estimates of carbon stocks, and consequently of carbon stock changes (i.e., the emission factors), for every land conversion included in our land use change modelling. The final emissions factors for each land conversion were derived from a combination of several different input parameters, each with its own uncertainty. In this section we describe the uncertainty estimates for each input parameter and the Monte Carlo analysis used to combine all of the individual input parameter uncertainties. At the end of this section we present the total emissions factor uncertainty, which considers spatial correlation across emissions factor errors. All of the uncertainty estimates, for each data input and region, are available on the public docket.

###### 2.4.4.2.8.2.1 Evaluation of Input Parameter Uncertainty

The foundation of our emissions factor uncertainty analysis was a rigorous assessment, following IPCC guidelines, of the uncertainty in all of the input parameters used to calculate the land use change emissions factors. Winrock generated 95% confidence intervals for every data input based on the quality, quantity, resolution and variability in the underlying data sources. The estimation of uncertainty was difficult for some parameters due to the absence of quantitative error analyses in the source data. Therefore, where no uncertainty information was available for a given parameter, expert judgement was used to identify an uncertainty range, and the upper bound was assumed as the uncertainty value. This produced final emission factor uncertainty values that are likely overestimated and thus conservative.

###### 2.4.4.2.8.2.1.1 Evaluation of Forest Carbon Stocks Input Parameter Uncertainty

Forest carbon stocks for countries in Latin America and Africa were estimated using the new pantropical carbon stock map of Saatchi et al. (in prep.). However, an accuracy assessment for this new map was not completed in time for our updated analysis. Therefore, although we used the new map to derive mean values, uncertainty around these mean values was estimated to be 19% using accuracy information reported for a prior forest biomass product for Latin America derived using a similar methodological approach (Saatchi et al. 2007). This represents a very conservative estimate (i.e., a high estimate) of uncertainty in our analysis because the Saatchi et al. estimates are very robust at the multi-state/regional scale. Because we used the same pantropical carbon stock map to derive estimates for Latin America and Africa, 19% uncertainty is also a conservative estimate for Africa.

Forest biomass carbon stocks for countries in South Asia were estimated using a map developed by Brown et al. (2001), but no formal accuracy assessment was performed as part of their analysis. Therefore, we consulted Table 4.7 in the IPCC 2006 Guidelines for AFOLU to see what the reported uncertainty was around Tier 1 aboveground biomass estimates. Biomass ranges are reported by continent and ecological zone, with extremely wide ranges in many cases (e.g., mean biomass of subtropical humid forests in Asia is 180 t ha-1, with a range of 10 to 560 t ha-1). Because the Brown et al. (2001) map was derived using some Tier 2 (country-level) information, we assumed the uncertainty of the Brown et al. (2001) product to be lower than uncertainty for Tier 1 IPCC values and therefore assigned Asia biomass carbon stocks an uncertainty value of 50%. This was done to reflect the somewhat better prediction of biomass over IPCC Tier 1 default values.

Some data sources provided accuracy information in the original documentation, and therefore this information was used to assign uncertainty values to the country-level estimates derived for our analysis. Uncertainty was estimated for biomass carbon estimates in Eastern Europe and Canada (33%; Myneni et al. 2001), China (36%, Piao et al. 2005), Russia (40%, Houghton et al. 2007), various EU countries (11%, Nabuurs et al. 2003), and the United States (7-31% depending on state, Blackard et al. 2007). For other EU countries in which biomass carbon stocks were estimated using FAO data, an uncertainty value of 50% was assumed. We assigned an uncertainty value of 80% to the global carbon stock map developed by Reusch and Gibbs (2008), as this was developed primarily from IPCC Tier 1 information. A summary of uncertainty values used for forest biomass carbon stocks is presented in Table 2.4 .

In cases where data sources reported only aboveground biomass (or aboveground carbon) stocks only, we used regression equation information presented in Cairns et al. (1997) to add in the uncertainty related to estimating belowground biomass. The relationship in Cairns et al. (1997) relates belowground biomass to aboveground biomass, and the equation has an adjusted R2 value of 0.83. Therefore, we assumed the uncertainty (the percent of variation in belowground biomass not explained by aboveground biomass to be 7%.

**Table 2.4-50. Uncertainty values used for forest carbon stock estimates.**

| Data Source | Uncertainty Value | Justification |
|---|---|---|
| Saatchi et al. (2007) | 19% (aboveground), 17% (belowground) | Accuracy assessment based on past product (Saatchi et al. 2007) |
| Brown et al. (2001) | 50% (above- and belowground combined) | No formal accuracy assessment given; therefore expert opinion as 50% (some country-level data used therefore better than IPCC Tier 1) |
| Blackard et al. (2007) | 7 – 31% (aboveground), 17% (belowground) | Pixel-level uncertainty values averaged per state |
| Houghton et al. (2007) | 40% (above- and belowground combined) | Reported in original source |
| Myneni et al. (2001) | 27% (aboveground), 33% (belowground) | Reported in original source |
| Nabuurs et al. (2003) | 11% (above- and belowground combined) | Reported in original source |
| Piao et al. (2005) | 36% (above- and belowground combined) | Reported in original source |
| Reusch and Gibbs (2008) | 80% (above- and belowground combined) | IPCC Tier 1 |
| FAO (2006) | 50% (above- and belowground combined) | No formal accuracy assessment given; therefore expert opinion as 50% (some country-level data used therefore better than IPCC Tier 1) |

###### 2.4.4.2.8.2.1.2 Evaluation of Cropland, Grassland, Savanna, Shrubland and Wetland Carbon Stocks Input Parameter Uncertainty

Uncertainty around carbon stocks in annual croplands and grasslands was assumed to be 75%, based on default error margins reported in IPCC Table 5.9 and 6.4, respectively. In the absence of any uncertainty information for savanna, shrubland, perennial cropland and wetlands, uncertainty in carbon stock estimates for these other land cover categories was also estimated as 75% in keeping with the default uncertainty values presented in the IPCC Guidelines. The one exception to the 75% uncertainty assumption was Brazil, for which more precise information was available on the carbon stocks along a continuum of grasslands, savanna and shrublands. The uncertainty for these land cover types was estimated as 0.6%, 0.9% and 16%, respectively, derived from the standard errors reported in the original data source (de Castro and Kaufmann 1998). The higher uncertainty in shrubland carbon stocks is likely related to the comparatively large variation in tree cover (and therefore carbon stocks) in shrublands compared to grasslands and savannas. Uncertainty in the mixed land cover category was estimated as the average of the uncertainty in forest, crop, shrub and grass categories in keeping with the IGBP description of this land cover class.

###### 2.4.4.2.8.2.1.3 Evaluation of Soil Carbon Input Parameter Uncertainty

The data source used to estimate initial (i.e., reference) soil carbon stocks was changed from FAO/UNESCO’s Soil Map of the World to the newly released World Harmonized Soil Database for the updated analysis. This was done because the spatial resolution of the new data product is much improved compared to the FAO map. However, neither data source reports information on accuracy or uncertainty. In the absence of any reliable information about the uncertainty of the estimates, we assumed an uncertainty value of 90%, which is the default error estimate for Tier 1 default soil organic carbon stocks in all soil-climate types (derived from Table 2.3 of the IPCC 2006 Guidelines).

Carbon stocks after land use conversion to cropland were calculated using IPCC Equation 2.25 as the initial soil carbon stock modified by land use, management, and input factors that relate to how the soil is managed. Default soil factors presented in Table 5.5 of the 2006 IPCC Guidelines were used, assuming conversion to long-term cultivated annual cropland under full tillage and medium inputs. The error margin for the land use factor was estimated using default values presented in Table 5.5 of the 2006 IPCC Guidelines and ranged from 9 to 61% depending on temperature and moisture regime. After carbon stocks after land use conversion were estimated, changes in carbon stocks due to land conversion were calculated as the difference between initial and final carbon stocks divided by an assumed transition period of 20 years during which soil emissions take place.

#### 2.4.4.2.8.2.1.4 Evaluation of Foregone Forest Sequestration Input Parameter Uncertainty

Uncertainty values for foregone forest carbon sequestration were derived from standard errors reported in the original data sources. Uncertainty in carbon sequestration rates ranged from 20% to 50%, with higher uncertainty in tropical regions.

#### 2.4.4.2.8.2.1.5 Evaluation of Clearing with Fire Input Parameter Uncertainty

Fire emissions were calculated in the updated analysis when land is cleared for cropland in a region where fire is assumed to be used as a means of site preparation for the new land use. Fire emissions were calculated following IPCC Guidelines as the product of initial carbon stocks, a combustion factor (define) and a GHG emission factor (define). Combustion factors were estimated per land cover type using information on standard errors reported on combustion factors in de Castro and Kaufmann (1998). Uncertainties in combustion factors ranged from 42% to 69%. IPCC defaults were used to estimate uncertainty in the $CH_4$ and $N_2O$ emission factors and ranged from 59% to 78% depending on land cover type burned.

#### 2.4.4.2.8.2.2 Monte Carlo Analysis of Combined Emissions Factor Uncertainty

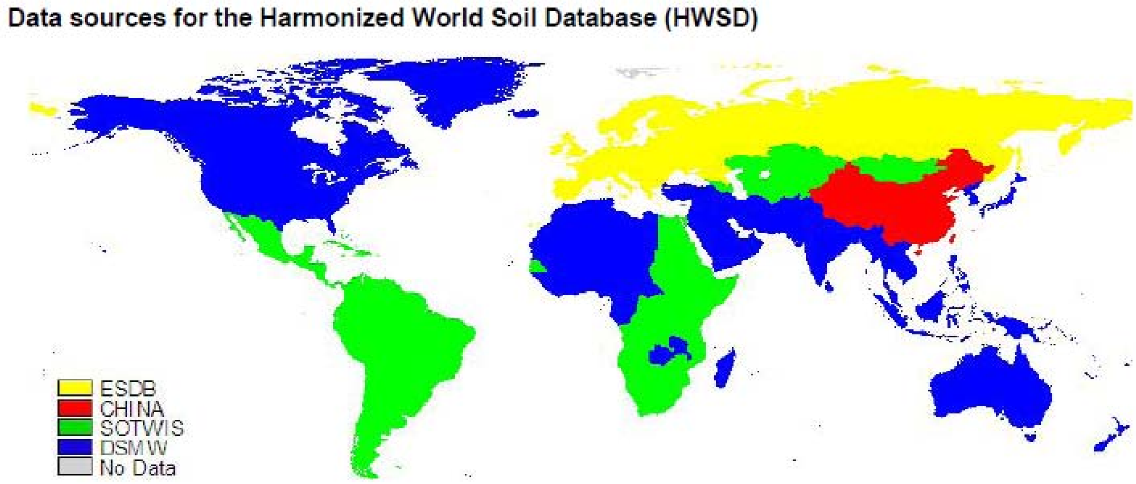
The uncertainties in individual parameters of an emission factor can be combined using either (1) simple error propagation (IPCC Tier 1) or (2) Monte Carlo simulation (IPCC Tier 2). We followed the Tier 2 approach.

One of the inputs required for the Monte Carlo uncertainty model is an estimate of the degree of correlation among different variables – both the correlation of one variable across space as well as the correlation of one variable to any others used in the analysis. This is in contrast to the IPCC error propagation approach, which assumes no correlation. The assumed correlations among different data inputs used to calculate uncertainty in emission factors using the Monte Carlo approach are summarized below.

Forest carbon stocks were derived from various sources, and therefore estimates for certain countries are correlated, i.e. errors in estimates that came from the same data source are assumed to be correlated. The correlation groups for forest carbon stocks are shown in Figure 2.4-34 above. All countries use the same equation that relates belowground biomass to aboveground biomass (Mokany et al. 2006), therefore we assumed that belowground biomass is perfectly correlated to aboveground biomass.

Although the World Harmonized Soil Database was used to estimate soil carbon stocks in the updated analysis, the dataset was developed by compiling different data sources together, and therefore soil carbon stocks are not correlated across all regions. The regional distribution of data sources is shown in Figure 2.4-43 below.

**Figure 2.4-43. Correlation groups for soil carbon stocks**



Note: Different colors represent different correlation groups.

Grassland carbon stocks were estimated using IPCC default carbon stock values and weighting the carbon stock based on the proportion of each country falling within each ecological zone. Correlation groups for these land cover categories were determined by assuming that countries with the same dominant ecological zone were correlated (i.e., all use the same carbon stock value). In addition, carbon stocks of grassland, shrubland and savanna were all assumed to be correlated to each other because we used a simple proportional approach to estimate the carbon stocks of savanna and shrubland (based on the grassland value).

All annual croplands have an assumed carbon stock of 5 t C $ha^{-1}$ and therefore all regions are correlated for this input parameter. Perennial croplands in Indonesia and Malaysia are assumed to be oil palm, and are therefore these regions are correlated, while perennial croplands in the rest of the world are assumed to be in a different correlation group than Indonesia and Malaysia (and have carbon stocks equivalent to that of sugarcane).

Correlation groups for lost forest sequestration are delineated by data sources, described above, such that lost forest sequestration across the tropics is correlated.

To estimate the uncertainty in each land conversion emissions factor, a Monte Carlo analysis was completed using the uncertainty estimates and correlation groups specified for each data input. For the Monte Carlo analysis we treated the data inputs as variables and assumed that each variable's uncertainty distribution is normal with a standard deviation equal to the uncertainty value times the mean divided by 100, converting the uncertainty range to a fraction then dividing by 2.[NNNNNNN]

To calculate emission factors, Monte Carlo model first generates pseudo random values for the variables above using the mean, calculated standard deviations, and pseudo random values for a Normal (0,1) distribution. Note that the resulting values after applying the mean and standard deviations are all constrained to be greater than 0.

The Monte Carlo model then used these pseudo random variables to calculate intermediate emissions variables for each country and administrative unit in each Monte Carlo iteration. 15,000 iterations were generated to calculate the mean and 95% confidence intervals for the land use change emissions factors. The uncertainty ranges from the emissions factor estimates, excluding the uncertainty from the MODIS data, are presented below for select land conversions and for all of the FAPRI-CARD regions.

Table 2.4-51 shows the contribution of uncertainty in our emissions factor estimates to total uncertainty by land conversion category and region. The uncertainty from emissions factors is generally larger than the uncertainty from our satellite data analysis (see Table 2.4-49 for uncertainty from the satellite data). The uncertainty ranges, as a percent of the mean, are very large in certain regions, such as Egypt, where the mean emissions factor estimates are very small.

**Table 2.4-51.**
**Contribution of Emissions Factor Estimates to Uncertainty in the 30-yr Weighted Land Conversion Emissions Factors**
**(+/- 95% confidence intervals as percent of mean)**

| FAPRI-CARD Region | Natural to Annual | Annual to Natural | Natural to Pasture | Pasture to Natural |
|---|---|---|---|---|
| Algeria | 142% | 143% | 69% | 69% |
| Argentina | 74% | 80% | 18% | 27% |
| Australia | 59% | 57% | 43% | 35% |
| Bangladesh | 65% | 64% | 39% | 49% |
| Brazil: Amazon Biome | 23% | 37% | 19% | 41% |
| Brazil: Central-West Cerrados | 45% | 41% | 28% | 34% |
| Brazil: Northeast Coast | 48% | 50% | 28% | 22% |
| Brazil: North-Northeast Cerrados | 39% | 38% | 25% | 22% |
| Brazil: South | 56% | 52% | 33% | 22% |
| Brazil: Southeast | 47% | 40% | 38% | 24% |
| Canada | 58% | 52% | 32% | 47% |
| China | 57% | 43% | 33% | 29% |
| New Zealand | 60% | 54% | 75% | 52% |
| Colombia | 55% | 54% | 20% | 43% |
| Cuba | 53% | 43% | 34% | 36% |
| Egypt | 595% | 401% | 42% | 50% |
| EU | 56% | 61% | 38% | 48% |
| Guatemala | 53% | 47% | 24% | 36% |
| India | 57% | 63% | 38% | 39% |
| Indonesia | 42% | 46% | 47% | 49% |
| Iran | 81% | 76% | 70% | 67% |

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[NNNNNNN] The uncertainty range is defined as the absolute value of the 97.5th percentile of the distribution minus the 2.5th percentile of the distribution, divided by the mean value of the distribution which is 2 standard deviations divided by the mean for a random variable with a normal distribution.

| FAPRI-CARD Region | Natural to Annual | Annual to Natural | Natural to Pasture | Pasture to Natural |
|---|---|---|---|---|
| Iraq | 57% | 57% | 74% | 72% |
| Ivory Coast | 42% | 53% | 16% | 49% |
| Japan | 54% | 34% | 43% | 32% |
| Malaysia | 42% | 44% | 47% | 50% |
| Mexico | 61% | 56% | 29% | 38% |
| Morocco | 95% | 92% | 71% | 74% |
| Myanmar | 54% | 47% | 54% | 50% |
| Nigeria | 63% | 68% | 16% | 37% |
| Other Africa | 52% | 57% | 19% | 40% |
| Other Asia | 53% | 48% | 45% | 38% |
| Other CIS | 53% | 49% | 56% | 55% |
| Other Eastern Europe | 62% | 48% | 34% | 39% |
| Other Latin America | 47% | 40% | 21% | 35% |
| Other Middle East | 88% | 87% | 61% | 63% |
| Pakistan | 81% | 90% | 76% | 70% |
| Paraguay | 52% | 50% | 15% | 28% |
| Peru | 34% | 45% | 15% | 43% |
| Philippines | 54% | 47% | 53% | 51% |
| Rest of World | 37% | 37% | 34% | 32% |
| Russia | 60% | 56% | 40% | 39% |
| South Africa | 46% | 43% | 32% | 39% |
| South Korea | 56% | 36% | 23% | 24% |
| Taiwan | 59% | 65% | 73% | 77% |
| Thailand | 49% | 48% | 38% | 37% |
| Tunisia | 119% | 116% | 58% | 66% |
| Turkey | 72% | 73% | 51% | 57% |
| Ukraine | 62% | 48% | 51% | 52% |
| Uruguay | 83% | 86% | 47% | 47% |
| US | 45% | 43% | 28% | 41% |
| Uzbekistan | 50% | 58% | 59% | 69% |
| Venezuela | 57% | 47% | 34% | 48% |
| Vietnam | 44% | 43% | 42% | 41% |
| Western Africa | 62% | 64% | 7% | 23% |

#### 2.4.4.2.8.3 Evaluation of Total Uncertainty in International Land Conversion GHG Emissions Impacts

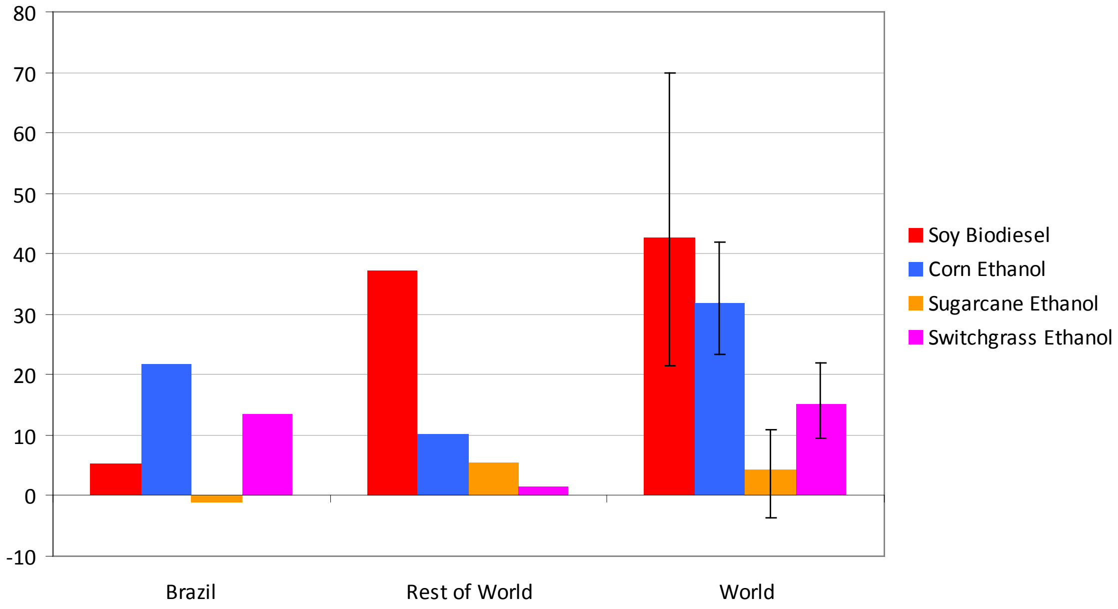
Total uncertainty in land use change GHG emissions was estimated for every renewable fuel scenario by combining the satellite data and emissions factor uncertainty estimates. The Monte Carlo model generated 15,000 iterations by generating 300 cases where it varied the pseudo-random values for historic land used changes and, for each of these 300 cases, generated 50 iterations where it varied the pseudo-random values for the variables used to calculate the emissions factors.

Within each of the 300 land use cases, the model first took the reported land use change from MODIS and remapped it to the simulated land use change using the MODIS version 5 confusion matrix and the uncertainties derived from the confusion matrix. This provided land use in 2007 and land use change from 2001 to 2007 for up to 10x10=100 combinations of land use in 2001 and land use in 2007.

Next, the Monte Carlo model calculates emission factors for each of the 50 iterations within the land use case for each of the 42 land use change possibilities (e.g., forest to cropland) for each country and administrative unit. The model calculated annual land use change emissions for up to 80 years, and also 30-year aggregated emissions factors. The model then used the land use change to calculate weighted average emission factors for each of the 54 FAPRI-CARD regions and each of the 12 land conversion options (e.g., annual crops to natural eco-systems). Finally, the model reports mean emissions as well as 95% confidence ranges. It also produces the mean and uncertainty ranges for each of the FAPRI-CARD scenario results, i.e., for each renewable fuel type.

Figure 2.4-44 provides a graphical illustration of the total uncertainty ranges for international land use change emissions. Error bars are only presented for the global estimates because Brazil and Rest of World are aggregate regions and the uncertainty ranges are not the sum of the sub-regions. The error bars in the figure present the low and high ends of the 95% confidence range for international land use change GHG emissions. Table 2.4-52 and Table 2.4-53 include the low and high ends of the 95% confidence range for land conversion GHG emissions for each region and renewable fuel scenario. Taken together, the values in these tables form the 95% confidence intervals for land use change GHG impacts in each region. Note that given the nature of stochastic modeling, the total low and high ends of the range are not the sum of the regions.

**Figure 2.4-44. International land use change GHG emissions by renewable fuel with 95% confidence intervals, 2022 (kgCO2e/mmBTU)**



# Table 2.4-52. Low end of the 95% confidence range for international land use change GHG emissions by renewable fuel, 2022
# (kgCO2e/mmBTU)

| **FAPRI-CARD Region** | **Corn Ethanol** | **Soy Biodiesel** | **Sugarcane Ethanol** | **Switchgrass Ethanol** |
|---|---|---|---|---|
| Algeria | 0.00 | 0.00 | 0.00 | 0.00 |
| Argentina | -0.46 | -0.35 | -0.94 | 0.05 |
| Australia | 0.28 | -0.13 | -0.02 | 0.10 |
| Bangladesh | -0.72 | -0.95 | -0.21 | 0.04 |
| Brazil: Amazon Biome | 10.48 | -27.56 | 3.94 | 4.45 |
| Brazil: Central-West Cerrados | 2.67 | 0.62 | 0.26 | 1.76 |
| Brazil: Northeast Coast | 0.18 | 0.07 | 0.27 | 0.07 |
| Brazil: North-Northeast Cerrados | 0.49 | 2.19 | 0.37 | 0.87 |
| Brazil: South | 0.73 | 3.26 | -7.83 | 0.79 |
| Brazil: Southeast | 0.69 | -0.02 | -9.71 | 0.41 |
| Canada | -0.11 | 0.50 | -0.16 | 0.04 |
| China | 0.26 | 3.04 | -0.17 | 0.11 |
| New Zealand | 0.01 | 0.16 | 0.00 | 0.01 |
| Colombia | 0.01 | 1.49 | 0.17 | 0.09 |
| Cuba | 0.02 | 0.06 | 0.09 | 0.00 |
| Egypt | -0.02 | -0.01 | -0.01 | -0.01 |
| EU | 0.19 | 0.99 | 0.14 | 0.13 |
| Guatemala | 0.11 | 0.12 | 0.08 | 0.03 |
| India | 0.42 | 1.16 | 0.27 | -3.52 |
| Indonesia | 1.97 | 2.42 | 0.67 | -0.19 |
| Iran | 0.02 | 0.10 | 0.01 | 0.02 |
| Iraq | 0.00 | 0.02 | 0.00 | 0.01 |
| Ivory Coast | 0.04 | 0.22 | 0.06 | 0.08 |
| Japan | 0.55 | 0.03 | 0.01 | -1.00 |
| Malaysia | -0.18 | 1.52 | 0.02 | 0.02 |
| Mexico | 0.36 | 1.55 | 0.01 | -0.02 |
| Morocco | 0.01 | 0.01 | 0.00 | 0.01 |
| Myanmar (Burma) | -0.09 | 0.07 | 0.00 | -0.02 |
| Nigeria | 0.34 | 0.34 | 0.09 | 0.15 |
| Africa, Other | 0.52 | 3.05 | 0.24 | 0.36 |
| Asia, Other | 0.06 | 0.20 | 0.00 | -0.15 |
| CIS, Other | -2.43 | -1.26 | -0.24 | -0.16 |
| Eastern Europe, Other | 0.00 | 0.09 | 0.01 | 0.02 |
| Latin America, Other | 0.23 | 1.71 | 0.18 | 0.13 |
| Middle East, Other | 0.00 | 0.02 | 0.00 | 0.01 |
| Pakistan | -0.15 | 0.13 | 0.02 | 0.04 |
| Paraguay | -0.03 | -0.88 | 0.13 | 0.20 |
| Peru | -0.84 | 1.55 | 0.05 | 0.05 |
| Philippines | 0.62 | 0.63 | 0.26 | 0.17 |
| Rest of World | 0.66 | 1.81 | 0.21 | 0.19 |
| Russia | -0.01 | 0.13 | 0.04 | 0.05 |
| South Africa | -0.04 | 0.39 | 0.03 | 0.03 |
| South Korea | 0.00 | 0.01 | 0.00 | 0.00 |
| Taiwan | -0.01 | 0.01 | 0.00 | 0.00 |
| Thailand | 0.12 | 0.23 | 0.09 | 0.09 |
| Tunisia | 0.00 | 0.02 | 0.00 | 0.00 |
| Turkey | -0.18 | 0.05 | 0.01 | 0.01 |
| Ukraine | -0.21 | 0.04 | 0.01 | 0.01 |
| Uruguay | -0.05 | 0.20 | 0.01 | 0.02 |
| United States |  |  | 0.62 |  |
| Uzbekistan | -0.80 | -0.51 | -0.10 | -0.08 |
| Venezuela | -0.38 | 0.73 | 0.02 | 0.01 |
| Vietnam | 0.13 | 0.09 | 0.07 | 0.04 |
| Western Africa | 0.01 | 0.04 | 0.02 | 0.04 |
| **TOTAL** | **23.45** | **21.37** | **-3.66** | **9.58** |

Note: given the nature of stochastic modeling, the total low and high 95% confidence ranges do not equal the sum of the regions.

## Table 2.4-53. High end of the 95% confidence range for international land use change GHG emissions by renewable fuel, 2022 (kgCO2e/mmBTU)

| FAPRI-CARD Region | Corn Ethanol | Soy Biodiesel | Sugarcane Ethanol | Switchgrass Ethanol |
|---|---|---|---|---|
| Algeria | 0.06 | 0.05 | 0.02 | 0.04 |
| Argentina | -0.18 | 0.64 | -0.17 | 0.27 |
| Australia | 0.77 | 0.17 | 0.02 | 0.28 |
| Bangladesh | -0.18 | -0.23 | -0.05 | 0.17 |
| Brazil: Amazon Biome | 15.27 | -6.87 | 5.68 | 6.80 |
| Brazil: Central-West Cerrados | 5.82 | 18.14 | 1.20 | 5.54 |
| Brazil: Northeast Coast | 0.69 | 0.23 | 1.27 | 0.22 |
| Brazil: North-Northeast Cerrados | 1.31 | 9.18 | 0.71 | 2.19 |
| Brazil: South | 3.40 | 15.85 | -1.24 | 3.65 |
| Brazil: Southeast | 2.61 | 2.25 | 1.20 | 1.27 |
| Canada | 0.02 | 0.97 | -0.06 | 0.12 |
| China | 0.91 | 6.05 | 0.14 | 0.89 |
| New Zealand | 0.08 | 1.05 | 0.02 | 0.05 |
| Colombia | 0.53 | 2.46 | 0.33 | 0.21 |
| Cuba | 0.08 | 0.13 | 0.19 | 0.01 |
| Egypt | 0.01 | 0.01 | 0.00 | 0.01 |
| EU | 0.78 | 2.43 | 0.48 | 0.47 |
| Guatemala | 0.35 | 0.22 | 0.14 | 0.10 |
| India | 1.41 | 3.83 | 0.72 | -1.11 |
| Indonesia | 4.81 | 5.79 | 1.63 | -0.07 |
| Iran | 0.17 | 0.35 | 0.10 | 0.11 |
| Iraq | 0.01 | 0.06 | 0.01 | 0.02 |
| Ivory Coast | 0.10 | 0.45 | 0.14 | 0.19 |
| Japan | 1.97 | 0.12 | 0.03 | -0.48 |
| Malaysia | -0.05 | 4.49 | 0.05 | 0.06 |
| Mexico | 1.77 | 2.96 | 0.23 | 0.16 |
| Morocco | 0.09 | 0.10 | 0.05 | 0.07 |
| Myanmar (Burma) | -0.04 | 0.22 | 0.02 | -0.01 |
| Nigeria | 1.30 | 0.89 | 0.33 | 0.55 |
| Africa, Other | 1.96 | 4.73 | 0.67 | 0.93 |
| Asia, Other | 0.21 | 0.49 | 0.00 | -0.04 |
| CIS, Other | -0.58 | -0.15 | -0.01 | 0.06 |
| Eastern Europe, Other | 0.05 | 0.19 | 0.03 | 0.04 |
| Latin America, Other | 0.81 | 2.85 | 0.35 | 0.29 |
| Middle East, Other | 0.00 | 0.09 | 0.02 | 0.04 |
| Pakistan | -0.02 | 0.71 | 0.11 | 0.27 |
| Paraguay | 0.08 | -0.07 | 0.21 | 0.33 |
| Peru | -0.23 | 2.21 | 0.12 | 0.13 |
| Philippines | 1.97 | 1.97 | 0.79 | 0.53 |
| Rest of World | 1.50 | 3.68 | 0.45 | 0.40 |
| Russia | 0.02 | 0.52 | 0.15 | 0.21 |
| South Africa | 0.13 | 0.78 | 0.07 | 0.07 |
| South Korea | 0.00 | 0.03 | 0.00 | 0.01 |
| Taiwan | 0.00 | 0.07 | 0.00 | 0.00 |
| Thailand | 0.34 | 0.59 | 0.22 | 0.24 |
| Tunisia | 0.06 | 0.08 | 0.02 | 0.04 |
| Turkey | -0.04 | 0.17 | 0.06 | 0.04 |
| Ukraine | -0.06 | 0.34 | 0.02 | 0.02 |
| Uruguay | -0.01 | 0.58 | 0.07 | 0.10 |
| United States |  | 1.03 |  |  |
| Uzbekistan | -0.15 | -0.09 | -0.02 | -0.01 |
| Venezuela | -0.04 | 1.55 | 0.07 | 0.04 |
| Vietnam | 0.35 | 0.22 | 0.16 | 0.10 |
| Western Africa | 0.05 | 0.14 | 0.06 | 0.14 |
| **TOTAL** | **41.89** | **69.80** | **10.99** | **21.86** |

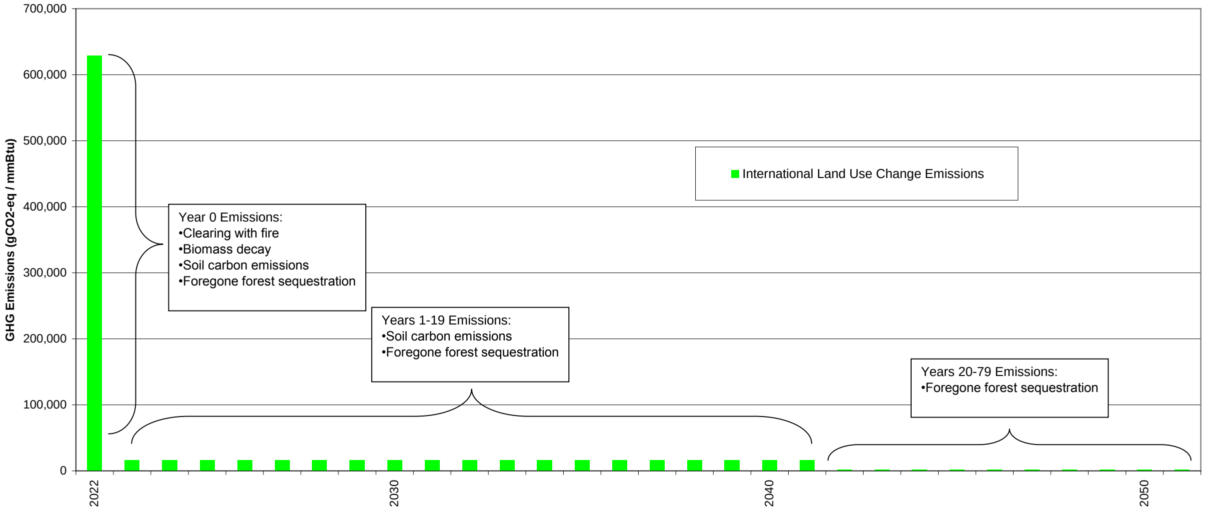
Note: given the nature of stochastic modeling, for the low and high 95% confidence ranges total emissions do not equal the sum of the regions.

### 2.4.5 Accounting for Lifecycle GHG Emissions Over Time

When comparing the lifecycle GHG emissions associated with biofuels to those associated with gasoline or diesel emissions, it is critical to take into consideration the time profile associated with each fuel's GHG's emissions stream. With gasoline, a majority of the GHG emissions associated with extraction, conversion, and combustion are likely to be released over a short period of time (i.e., annually) as crude oil is converted into gasoline or diesel fuel which quickly pass to market.

In contrast, the GHG emissions from the production of a typical biofuel (e.g., corn-based ethanol) may continue to occur over a long period of time. As with petroleum based fuels, GHG emissions are associated with the conversion and combustion of biofuels in every year they are produced. In addition, GHG emissions could be released through time if new acres are needed to produce corn or other crops for biofuels. The GHG emissions associated with converting land into crop production would accumulate over time with the largest release occurring in the first few years due to clearing with fire or biomass decay. After the land is converted, moderate amounts of soil carbon would continue to be released for approximately 20 years. Furthermore, there would be foregone sequestration associated with the fact that the forest would have continued to sequester carbon had it not been cleared for approximately 80 years (See Figure 2.4-45).

**Figure 2.4-45.**
**Timing of International Land Use Change Emissions in the Corn Ethanol Scenario (gCO2e / mmBTU)**



While biomass feedstocks grown each year on new cropland can be converted to biofuels that offer an annual GHG benefit relative to the petroleum product they replace, these benefits may be small compared to the upfront release of GHG emission. Depending on the specific biofuel in question, it can take many years for the benefits of the biofuel to make up for the large initial releases of carbon that result from land conversion (e.g., the payback period).

As required by EISA, our analysis must demonstrate whether biofuels reduce GHG emissions by the required amount relative to the 2005 petroleum baseline. A payback period alone cannot answer that question. Since the payback period is not sufficient for our analysis, we have developed methods for capturing the stream of emissions and benefits over time. For our analytical purposes, it is important for us to determine how the time profiles of emission releases of different fuels compare. It is useful to have a unitary metric that allows for a direct comparison of biofuels compared to gasoline or diesel, which requires an accounting system for GHG emissions over time. When considering the time profile of GHG emissions, the two assumptions that have a significant impact on the determination of whether a biofuel meets the emissions reduction threshold include: 1) the time period considered and 2) the discount rate we apply to future emissions. The proposed rule presented results using a 100-year time horizon and a 2% discount rate, as well as results with a 30-year time horizon and a 0% discount rate.

Based on input from the expert peer review and public comments, EPA has chosen to analyze lifecycle GHG emissions using a 30 year time period, over which emissions are not discounted, i.e., a zero discount rate is applied to future emissions.

The main reasons for why a short time period is appropriate: this time frame is the average life of a typical biofuel production facility; future emissions are less certain and more difficult to value, so the analysis should be confined insofar as possible to the foreseeable future; and a near-term time horizon is consistent with the latest climate science that indicates that relatively deep reductions of heat-trapping gasses are needed to avoid catastrophic changes due to a warming climate.

EPA has decided not to discount (i.e., use a 0% discount rate) GHG emissions due to the many issues associated with applying an economic concept to a physical parameter. First, it is unclear whether EISA intended lifecycle GHG emissions to be converted into a metric whose underpinnings rest on principals of economic valuation. A more literal interpretation of EISA is that EPA should consider only physical GHG emissions. Second, even if the principle of tying GHG emissions to economic valuation approaches were to be accepted, there would still be the problem that there is a lack of consensus in the scientific community about the best way to translate GHG emissions into a proxy for economic damages. Also, there is a lack of consensus as to the appropriate discount rate to apply to GHG lifecycle emissions streams through time. Finally, since EPA has decided to base threshold assessments of lifecycle GHG emissions on a 30 year time frame, the issue of whether to discount GHG emissions is not as significant as if the EPA had chosen the 100 year time frame to assess GHG emissions impacts.

### 2.4.6 Feedstock Transport

The GHG impacts of transporting biofuel feedstock from the field to the biofuel facility and transporting co-products from the biofuel facility to the point of use were included in this analysis. The GREET default of truck transportation of 50 miles was used to represent corn and soybean transportation from farm to plant. This includes 10 miles from farm to stacks and 40 miles from stacks to plant. Transportation assumptions for DGS transport were 14% shipped by rail 800 miles, 2% shipped by barge 520 miles, and 86% shipped by truck 50 miles. The percent shipped by mode was from data provided by USDA and based on Association of American

Railroads, Army Corps of Engineers, Commodity Freight Statistics, and industry estimates. The distances DGS were shipped were based on GREET defaults for other commodities shipped by those transportation modes. Default GREET assumptions were also used for cellulosic ethanol feedstock transport. Crop residues, switchgrass and forest wastes were all assumed to be shipped by truck from point of production to plant. Crop residue distance shipped was 30 miles, switchgrass distance was 40 miles, and forest waste was 75 miles. The GHG emissions from transport of these feedstocks and co-products are based on GREET default emission factors for each type of vehicle including capacity, fuel economy, and type of fuel used.

GHG emissions from the transport of sugarcane from the field to the ethanol production facility also depend on distance and the type of truck used. The average one-way distance in 2002 was 20 km (12.4 mi)[600] . Over time, transport distance has increased to 23 km for 2005/2006, and is expected to be close to 30 km (18.6 mi) by 2020.[601] In terms of trends for logistics, there has been a replacement of single load trucks by trucks with lower specific fuel consumption and higher load capacities (3 to 4 wagons).

**Table 2.4-54. Sugarcane Transportation Inputs**

| **Parameter** | **Units** | **GREET Default** | **GREET ISJ (2008)[602]** | **2002** | **2005/ 2006** | **Scenario 2020** |
|---|---|---|---|---|---|---|
| Transportation distance (one-way) | km | 19.3 | 20 | 20 | 23 | 30 |
| Truck diesel use efficiency | ml/(t*km) | 27.7 | 14.8 | 20.4 | 19.1 | 16.1 |
| Diesel consumption | ml/tonne cane | 534 | 296 | 408 | 439 | 483 |

As we are projecting to a 2022 case, we used the projections available for the 2020 scenario given in Table 2.4-54, along with a revised truck payload assumption based on comments we received, to estimate GREET inputs for truck payload (tons), fuel economy of the truck (mpg), and the average one-way distance from field to the mill (miles). Specifically, we assumed a truck payload of 42 tons[603], fuel economy of 3.8 mpg, and an average distance of 19 miles. We incorporated these revised inputs into a recent release of the GREET model to estimate the GHG impacts of sugarcane transport. [604]

### 2.4.7 Biofuel Processing

GHG emissions from renewable fuel production were calculated by multiplying the BTUs of the different types of energy inputs at biofuel process plants by emissions factors for combustion of those fuel sources. The BTU of energy input was determined based on analysis of the industry and specific work done as part of the NPRM. The emission factors for the different fuel types are from GREET and were based on assumed carbon contents of the different process fuels. The emissions from producing electricity in the U.S. were also taken from GREET and represent average U.S. grid electricity production emissions. The emissions from combustion of biomass fuel source are not assumed to increase net atmospheric $CO_2$ levels. Therefore, $CO_2$ emissions from biomass combustion as a process fuel source are not included in the lifecycle GHG inventory of the biofuel production plant. The following sections outline the assumptions used to model biofuel production for different feedstocks and fuel pathways.

#### 2.4.7.1 Corn Ethanol

One of the key sources of information on energy use for corn ethanol production was a study from the University of Illinois at Chicago Energy Resource Center. Between proposal and final rule, the study was updated to reflect more recent data, therefore, we incorporated the results of the updated study in our corn ethanol pathways process energy use for the final rule. We also updated corn ethanol production energy use for different technologies in the final rule based on feedback from industry technology providers as part of the public comment period. The main difference between proposal and final corn ethanol energy use values was a slight increase in energy use for the corn ethanol fractionation process, based on feedback from industry technology providers.

The two basic methods for producing ethanol from corn are dry milling and wet milling. In the dry milling process, the entire corn kernel is ground and fermented to produce ethanol. The remaining components of the corn are then either left wet if used in the near term or dried for longer term use as animal feed (dried distillers grains with solubles, or DGS). In the wet milling process, the corn is soaked to separate the starch, used to make ethanol, from the other components of the corn kernel. Wet milling is more complicated and expensive than dry milling, but it produces more valuable products (ethanol plus corn syrup, corn oil, and corn gluten meal and feeds). The majority of ethanol plants in the United States are dry mill plants, which produce ethanol more simply and efficiently.

For this analysis the amount of corn used for ethanol production as modeled by the FASOM and FAPRI-CARD models was based on yield assumptions built into those two models. Assumptions were ethanol yields of 2.71 gallons per bushel for dry mill plants and 2.5 gallons per bushel for wet mill plants (yields represents pure ethanol).

As mentioned above, in traditional lifecycle analyses, the energy consumed and emissions generated by a renewable fuel plant must be allocated not only to the renewable, but also to each of the by-products. However, for corn ethanol production, this analysis accounts for the DGS and other co-products use directly in the FASOM and FAPRI-CARD agricultural sector modeling described above. DGS are considered a partial replacement for corn and other animal feed and thus reduce the need to make up for the corn production that went into ethanol production. Since FASOM takes the production and use of DGS into account, no further allocation was needed at the ethanol plant and all plant emissions are accounted for here.

In terms of the energy used at renewable fuel facilities, there is a lot of variation between plants based on the process type (e.g., wet vs. dry milling) and the type of fuel used (e.g., coal vs. natural gas). There can also be variation between the same type of plants using the same fuel source based on the age of the plant and types of processes included, etc. For our analysis we considered different pathways for corn ethanol production. Our focus was to differentiate between facilities based on the key differences between plants, namely the type of plant and the type of fuel used. One other key difference we modeled between plants was the treatment of the co-products DGS. One of the main energy drivers of ethanol production is drying of the DGS. Plants that are co-located with feedlots have the ability to provide the co-product without drying. This has a big enough impact on overall results that we defined a specific category for wet vs.

dry co-product. One additional factor that appears to have a significant impact on GHG emissions is corn oil fractionation from DGS. Therefore, this category is also broken out as a separate category in the following section. See RIA Chapter 1.4 for a discussion of corn oil fractionation.

Furthermore, as our analysis was based on a future timeframe, we modeled future plant energy use to represent plants that would be built to meet requirements of increased ethanol production, as opposed to current or historic data on energy used in ethanol production. The energy use at dry mill plants was based on ASPEN models developed by USDA and updated to reflect changes in technology out to 2022 as described in RIA Chapter 1. The modeling provided energy use for the different types of dry mill ethanol plants as shown in Table 2.4-55.

## Table 2.4-55. 2022 Energy Use at Ethanol Plants w/CHP (BTU/gal)

| Type | Technology | NG Use | Coal Use | Biomass Use | Purchased Elec |
|---|---|---|---|---|---|
| Corn Ethanol – Dry Mill NG | Base Plant (dry DDGS) | 28,660 | | | 2,251 |
| | w/ CHP (dry DDGS) | 30,898 | | | 512 |
| | w/ CHP and Fractionation (dry DDGS) | 25,854 | | | 1,512 |
| | w/ CHP, Fractionation and Membrane Seperation (dry DDGS) | 21,354 | | | 1,682 |
| | w/ CHP, Fractionation, Membrane Seperation, and Raw Starch Hydrolysis (dry DDGS) | 16,568 | | | 1,682 |
| | Base Plant (wet DGS) | 17,081 | | | 2,251 |
| | w/ CHP (wet DGS) | 19,320 | | | 512 |
| | w/ CHP and Fractionation (wet DGS) | 17,285 | | | 1,512 |
| | w/ CHP, Fractionation and Membrane Seperation (wet DGS) | 12,785 | | | 1,682 |
| | w/ CHP, Fractionation, Membrane Seperation, and Raw Starch Hydrolysis (wet DGS) | 9,932 | | | 1,682 |
| Corn Ethanol – Dry Mill Coal | Base Plant (dry DGS) | | 35,824 | | 2,694 |
| | w/ CHP (dry DGS) | | 39,407 | | 205 |
| | w/ CHP and Fractionation (dry DGS) | | 33,102 | | 986 |
| | w/ CHP, Fractionation and Membrane Seperation (dry DGS) | | 27,477 | | 1,191 |
| | w/ CHP, Fractionation, Membrane Seperation, and Raw Starch Hydrolysis (dry DGS) | | 21,495 | | 1,191 |
| | Base Plant (wet DGS) | | 21,351 | | 2,694 |
| | w/ CHP (wet DGS) | | 24,934 | | 205 |
| | w/ CHP and Fractionation (wet DGS) | | 22,390 | | 986 |
| | w/ CHP, Fractionation and Membrane Seperation (wet DGS) | | 16,766 | | 1,191 |
| | w/ CHP, Fractionation, Membrane Seperation, and Raw Starch Hydrolysis (wet DGS) | | 13,200 | | 1,191 |
| Corn Ethanol – Dry Mill Biomass | 2022 Base Plant (dry DGS) | | | 35,824 | 2,694 |
| | 2022 Base Plant w/ CHP (dry DGS) | | | 39,407 | 205 |
| | 2022 Base Plant w/ CHP and Fractionation (dry DGS) | | | 33,102 | 986 |
| | 2022 Base Plant w/ CHP, Fractionation and Membrane Seperation (dry DGS) | | | 27,477 | 1,191 |
| | 2022 Base Plant w/ CHP, Fractionation, Membrane Seperation, and Raw Starch Hydrolysis (dry DGS) | | | 21,495 | 1,191 |
| | 2022 Base Plant (wet DGS) | | | 21,351 | 2,694 |
| | 2022 Base Plant w/ CHP (wet DGS) | | | 24,934 | 205 |
| | 2022 Base Plant w/ CHP and Fractionation (wet DGS) | | | 22,390 | 986 |
| | 2022 Base Plant w/ CHP, Fractionation and Membrane Seperation (wet DGS) | | | 16,766 | 1,191 |
| | 2022 Base Plant w/ CHP, Fractionation, Membrane Seperation, and Raw Starch Hydrolysis (wet DGS) | | | 13,200 | 1,191 |
| Corn Ethanol – Wet Mill | Plant with NG | 45,950 | | | |
| | Plant with coal | | 45,950 | | |
| | Plant with biomass | | | 45,950 | |

In response to comments received, we included corn oil fractionation and extraction as a potential source of renewable fuels for this final rulemaking. Based on research of various corn ethanol plant technologies, corn oil as a co-product from dry mill corn ethanol plants can be used as an additional biodiesel feedstock source. Dry mill corn ethanol plants have two different technological methods to withdraw corn oil during the ethanol production process. The fractionation process withdraws corn oil before the production of the DGS co-product. The resulting product is food-grade corn oil. The extraction process withdraws corn oil after the production of the DGS co-product, resulting in corn oil that is only suitable for use as a biodiesel feedstock.

Based on cost projections outlined in Section 4, it is estimated that by 2022, 70% of dry mill ethanol plants will conduct extraction, 20% will conduct fractionation, and that 10% will choose to do neither. These parameters have been incorporated into the FASOM and FAPRI-CARD models for the final rulemaking analysis, allowing for corn oil from extraction as a major biodiesel feedstock.

### 2.4.7.2 Corn Butanol

For the final rule analysis we included a scenario of converting corn starch into butanol. The production of corn was assumed to be the same as for ethanol production and based on the agricultural sector modeling described in the previous sections. However, the results were scaled based on the yield of butanol produced. Corn ethanol was assumed to have a processing yield of 2.7 gal/bu and an energy content of 76,000 Btu/gal which results in an overall energy yield of 206,280 Btu/bu. Corn butanol has a slightly lower processing yield of 2.12 gal/bu but a higher energy content of 99,827 Btu/gal for an overall energy yield of 212,153 Btu/bu. Therefore, on a per Btu produced basis corn butanol has slightly lower emissions compared to corn ethanol.

For process energy use we assumed the same types of technology as used for corn ethanol production. To estimate GHG emissions we used the average 2022 mix of plants and technologies which includes fractionation and 63% dry DGS and 37% wet DGS using natural gas as an energy source. Average energy use was 26,496 Btu NG per gallon produced and 4,642 Btu purchased electricity per gallon.

### 2.4.7.3 Biodiesel (including Algae)

Three scenarios for biodiesel production were considered, one utilizing soybean oil as a feedstock, one using yellow grease, and the last using algae oil. All three were assumed to be converted to biodiesel through the Fatty Acid Methyl Ester (FAME) process. The emissions from soybean growing were estimated through the agricultural sector modeling described in the previous sections. This section discusses the modeling for the production of algal oil, producing soybean oil, and conversion of al oils into biodiesel.

#### 2.4.7.3.1 Algae Oil Production

We developed our lifecycle analysis of the algae pathways primarily based on Aspen modeling provided by the National Renewable Energy Laboratory (NREL).[605] As the algae industry is still in its nascent stages and there are potentially many variations to the processing of algae, e.g. methods used for harvesting and lipid extraction, byproduct utilization, etc., it is challenging to say which set of technologies and configurations may be the most successful in the future. A recent publication summarized some of the potential algae-biofuel production pathways being considered.[606]

Two production pathways were evaluated at this time, one utilizing an open pond (op) system and the other a photobioreactor (PBR) system. More details on the assumptions used for those systems are described in the following sections as well as in the technical memorandum from NREL. We view this assessment as a starting point for evaluating algae-to-biofuel pathways and not as the only or preferred production configurations for algae. Nevertheless, we believe that the assumptions and scenarios chosen to represent the production of algae by 2022 are reasonable given the expert opinion solicited. Over time we plan to evaluate different variations of these pathways and to update the data and analyses as the algae industry grows and commercializes.

NREL evaluated three cases: a base case, an aggressive case, and a maximum case for each of the algae production pathways, i.e. op and PBR. A brief summary of the cases evaluated are given below:

<u>Base case:</u> algae yield = 25 $g/m^2/day$ (op), 63 $g/m^2/day$ (PBR); lipid content = 25% (corresponds to a reasonable but still challenging target for the near future)

<u>Aggressive case:</u> algae yield = 40 $g/m^2/day$ (op), 100 $g/m^2/day$ (PBR); lipid content = 50% (assumes identification of a strain with near optimal growth rates and lipid content)

<u>Maximum case:</u> algae yield = 60 $g/m^2/day$ (op), 150 $g/m^2/day$ (PBR); lipid content = 60% (represents the near theoretical maximum based on photosynthetic efficiencies)

<u>For all cases:</u> scale of facility = 10 MMgal/yr, 10% algae lost after production, 5% lipid lost in extraction

The production of algae-based biofuel consists of the following stages:

- Algae Cultivation
- Algae Harvesting
- Algae Oil Extraction and Recovery
- Algae Oil Transport to Biofuel Facility
- Algae Oil Conversion to Biofuel
- Biofuel Distribution

The modeling completed by NREL covered the first three production steps. We assumed that the biofuel facility would be co-located next to the algae oil production processes and thus transport emissions for the fourth step would be negligible. The last two steps were assumed to be similar to the conversion of soy oil to biodiesel and soy-based biodiesel distribution.

Algae require several inputs, including water, land, nutrients, and in most cases, light to sustain growth. The following Table 2.4-56 summarizes these main inputs for the various open pond and photobioreactor scenarios:

**Table 2.4-56. Inputs for Algae Cultivation**

| **Input** | **Base Case** | | **Aggressive Case** | | **Max Case** | |
|---|---|---|---|---|---|---|
| | op | PBR | op | PBR | op | PBR |
| Water Use: | | | | | | |
| Net water demand [MMgal/yr] | 9,740 | 720 | 3,830 | 320 | 2,710 | 250 |
| Net water demand [gal/gal lipid] | 974 | 72 | 383 | 32 | 271 | 25 |
| | | | | | | |
| Land Use [acre]: | | | | | | |
| Pond/PBR land size | 4,743 | 1,897 | 1,482 | 593 | 823 | 329 |
| Total plant land required | 7,079 | 3,795 | 2,212 | 1,186 | 1,229 | 659 |
| | | | | | | |
| Nutrient Use [ton/yr]: | | | | | | |
| Fertilizer for algae | 23,920 | 23,880 | 12,000 | 11,980 | 10,010 | 10,000 |
| Nutrients for anaerobic digester | 2,960 | 3,000 | 1,440 | 1,460 | 1,190 | 1,200 |
| | | | | | | |
| $CO_2$ Use: | | | | | | |
| $CO_2$ consumed [lb/lb algae produced] | 2 | 2 | 2 | 2 | 2 | 2 |
| Net $CO_2$ used from offsite flue gas [ton/yr] | 290,000 | 290,000 | 150,000 | 150,000 | 120,000 | 120,000 |

The scenarios assume water use is from low-value brackish or saline water pumped from an underground source rather than drawing from fresh water resources.[ooooooo] In areas where water is limited, fresh water may not be available at a reasonable cost and therefore may affect the feasibility of the system. One factor that could further limit water consumption is by cultivating algae in nutrient-rich eutrophic or mixed waters (e.g. animal litter, tertiary wastewater, and agricultural or industrial runoffs). This in turn could limit the amount of nutrients purchased for algae cultivation. An additional benefit to the use of wastewater is that an algae process that treats wastewater displaces carbon that would have been generated in conventional wastewater treatment processes.

Algae cultivation is expected to be able to use non-arable lands. As such, the conversion of carbon-rich lands to agriculture can be avoided and thus emissions from land-use change. Due to higher cell densities, the use of photobioreactors can lower land use in comparison to open pond systems. The scenarios assume 330 operating days/year and a solar exposure of 12

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[ooooooo] Some fresh makeup water is assumed to replace evaporative losses in the cooling system for the PBR system.

hours/day which implies that a site location is chosen which receives high year-round solar exposure.

The nutrients used in the process include fertilizers purchased for the algae and those needed to operate the anaerobic digesters. The fertilizers for the algae purchased are approximately 64% urea and 36% di-ammonium phosphate (DAP). The nutrients required to aid anaerobic digestion are primarily caustic with some phosphoric acid, urea and micronutrients.

Algae also consume $CO_2$ during cultivation. The scenarios assume that part of the $CO_2$ is recycled within the process from anaerobic digestion of spent biomass and part of the $CO_2$ is delivered from offsite flue gas, e.g. from power plant. Scenarios assume that $CO_2$ is delivered from a distance of 1.5 miles from a power plant or other emissions source. For both the open pond and PBR "base case", pure $CO_2$ was chosen where instead of transporting the entire flue gas material, the $CO_2$ is scrubbed out and transported under pressure to the facility.

Harvesting is necessary to recover biomass from the cultivation system. Commonly used techniques include flocculation, dissolved air flotation (DAF), centrifugation, microfiltration, and decantation. Wet biomass may also be dewatered or dried. Dewatering decreases the moisture content by draining or mechanical means. Additional drying can follow using e.g. drum dryer, freeze dryer, spray dryer, rotary dryer, or by solar drying. Primary harvesting under our scenarios occurs using natural settling to concentrate the algae from 0.05% to 1%. Secondary harvesting concentrates the algae to 10% via DAF using chitosan as a flocculant.

Oil from algae can be extracted through chemical or mechanical processes to separate the algal oil from the cell membrane. The TAGs (Triacylglycerides) are typically the main product which goes to biodiesel production. The remainder consists of carbohydrates, proteins, nutrients, and ash), usually referred to as the algal residue or spent biomass.

The extraction step is commonly regarded as the most speculative in terms of large-scale feasibility.[607] Thus extraction is a critical area of research going forward to achieve practical algal lipid production. Some of the more common methods are solvent extraction, supercritical fluid extraction, and mechanical extraction. Algal extraction under both op and PBR cases was assumed here to be carried out using mechanical extraction via high-pressure homogenization to lyse algae cells. Homogenization was chosen because it is the closest to the necessary processing scale investigated given current technology. Other extraction techniques discussed include solvent extraction, supercritical fluid extraction, osmotic shock, and sonication.

The lipids are assumed to be recovered via phase separation in a clarifier tank which allows contents to settle into lipid, water and spent biomass.

The spent biomass is assumed to be used in anaerobic digestion and power generation via gas turbine which provides power to run the plant. The other method commonly discussed is its use as animal feed; however, this was not assumed under these scenarios. Table 2.4-57 summarizes the net annual electricity required (purchased from grid) for the cultivation, harvesting, oil extraction and recovery stages. We assumed that the average U.S. grid electricity is used.

**Table 2.4-57. Net Annual Electricity Required (purchased from grid) [MM kwh/yr] for 10 MMgal/yr Lipid Production**

| Base Case | | Aggressive Case | | Max Case | |
|---|---|---|---|---|---|
| Op | PBR | Op | PBR | op | PBR |
| 60.2 | 35.7 | 27.0 | 18.8 | 19.8 | 16.0 |

### 2.4.7.3.2 Soybean Oil Production

For the soybean oil scenario, the energy use and inputs for the biodiesel production process were based on a model developed by USDA and used by EPA in the cost modeling of soybean oil biodiesel including crushing, as discussed in Chapter 4. Soybean crushing was modeled assuming yields of 11.2 lbs soybean oil/bu soybeans and energy use of 14,532 BTU of natural gas and 2,843 BTU of purchased electricity per gallon of biodiesel produced.

Similar to the case with corn ethanol co-products, we analyze the aggregate GHG emissions from soybean crushing and transesterification that occur as a result of increased demand for a particular biofuel. Therefore, any increase in soybean meal or soybean oil produced as a result of larger biodiesel volumes would take into account GHG emissions reductions from a decrease in the production of other feed and vegetable oil substitutes from our FASOM modeling.

### 2.4.7.3.3 Conversion of Oil to Biofuel

For the proposal we based biodiesel processing energy on a process model developed by USDA-ARS to simulate biodiesel production from the Fatty Acid Methyl Ester (FAME) transesterification process. In this process vegetable oil (triglyceride) is reacted with an alcohol (e.g., methanol) and a catalyst (e.g., sodium hydroxide) to produce biodiesel and glycerin. During the comment period USDA updated their energy balance for biodiesel production to incorporate a different biodiesel dehydration process based on a system which has resulted in a decrease in energy requirements. Soybean biodiesel transesterification was modeled assuming yields of one kilogram of biodiesel from a kilogram of soybean oil and energy use of 4,381 BTU of natural gas and 361 BTU of electricity per gallon of biodiesel produced.[608]

We assumed that the algae oil produced would be similar in quality as soy oil. Although it is possible that the algae oil may require an upgrading step such as degumming to remove phospholipids, this step was not included as there is no information at this time regarding the process logistics specific to algal-derived oil. Algae oil is also assumed to be converted to biodiesel through the transesterification process with the same energy and material requirements of soybean oil.

For the yellow grease case, no soybean agriculture emissions or energy use was included. Soybean crushing natural gas use was included as a surrogate for yellow grease processing (purification, water removal, etc.). Also, due to additional processing requirements, the energy use associated with producing biodiesel from yellow grease is higher than for soybean oil biodiesel production. The energy use for yellow grease biodiesel production was assumed to be 1.7 times the energy used for soybean oil biodiesel and yields of 0.94 kilograms of biodiesel from a kilogram of yellow grease.

GHG emissions from other biodiesel production raw material inputs were also included in the analysis. HCl, methanol, NaOCH3 and sodium hydroxide are used in the production of biodiesel and GHG emissions from producing the raw material inputs were also added to the model. Table 2.4-58 shows the values that were used to convert raw material inputs into GHG emissions used in the anlaysis.

**Table 2.4-58.**
**Lifecycle Factors for Biodiesel Raw Material Production**

| Factor | Unit | Methanol | Sodium Methoxide | Sodium Hydroxide | HCl |
|---|---|---|---|---|---|
| $CO_2$ | g/g | 0.401 | 0.966 | 0.923 | 1.011 |
| $CH_4$ | g/g | 0.003 | 0.002 | 0 | 0 |
| $N_2O$ | g/g | 3.9E-06 | 2.5E-06 | 0 | 0 |
| Total Energy | BTU/g | 19.05 | 24.10 | 9.67 | 9.35 |

Glycerin is a co-product of biodiesel production. Our proposal analysis did not assume any credit for this glycerin product. We have included for the final rule analysis that glycerin would displace residual oil as a fuel source on an energy equivalent basis. This is based on the assumption that the glycerin market would be saturated in 2022 and that glycerin produced from biodiesel would not displace any additional petroleum glycerin production. However, the biodiesel glycerin would not be a waste and a low value use would be to use the glycerin as a fuel source. The fuel source assumed to be replaced by the glycerin is residual oil.

### 2.4.7.4 Cellulosic Biofuel

For the cellulosic biofuel pathways, we updated our final rule energy consumption assumptions on process modeling completed by NREL. For the NPRM, NREL estimated energy use for the biochemical enzymatic process to ethanol route in the near future (2010) and future (2015 and 2022).[609] As there are multiple processing pathways for cellulosic biofuel, we have expanded the analysis for the FRM to also include thermochemical processes (Mixed-Alcohols route and Fischer-Tropsch to diesel route) for plants which assume woody biomass as its feedstock.[610,611]

Cellulosic biofuel can be produced through two main types of production processes, either fermentation or gasification. The fermentation option may show preference towards using more homogeneous feedstock sources like farmed trees (hardwoods), switchgrass and corn stover whereas more heterogeneous sources like forestry waste (typically softwoods) may prefer the gasification option due to processing challenges. For more information on key biomass feedstock considerations and the potential impact they may have on yields and processability within the biorefinery refer to the technical document provided by NREL.[612]

As discussed, we have worked with NREL to generate models of cellulosic ethanol and diesel fuel production. Table 2.4-59 shows the energy use required for the different cellulosic ethanol and F-T diesel production processes. For the biochemical pathway, process energy is assumed to be generated through the unfermentable portion (mainly lignin) of incoming biomass being burned for electricity production. The process is assumed to generate excess electricity per gallon of ethanol produced.

## Table 2.4-59. 2022 Energy Use at Cellulosic Biofuel Plants (BTU/gal)

| Type | Technology | Biomass Use | Diesel Fuel Use | Purchased Elec. | Sold Elec. |
|---|---|---|---|---|---|
| Cellulosic Ethanol – Enzymatic | Switchgrass feedstock & lignin used as fuel | 61,001 | | | -12,249 |
| | Corn stover feedstock & lignin used as fuel | 61,001 | | | -12,249 |
| | Forest waste feedstock & lignin used as fuel | 64,220 | | | -18,391 |
| Cellulosic Ethanol – Thermochemical | Switchgrass feedstock | 90,935 | 177 | | |
| | Corn stover feedstock | 90,935 | 177 | | |
| | Forest waste feedstock | 90,935 | 177 | | |
| | Farmed trees feedstock | 90,935 | 177 | | |
| Cellulosic Diesel – F-T | Switchgrass feedstock | 168,220 | 327 | 17 | |
| | Corn stover feedstock | 168,220 | 327 | 17 | |
| | Forest waste feedstock | 168,220 | 327 | 17 | |
| | Farmed trees feedstock | 168,220 | 327 | 17 | |

-

The benefit of electricity generation is the possibility of lowering greenhouse gas emissions by offsetting other forms of electricity production. This is captured in our analysis by assuming that the excess electricity produced by the ethanol plant will offset U.S. grid electricity production. Therefore, GHG emissions from U.S. grid electricity are calculated for the amount of excess electricity produced based on GREET defaults for electricity production and subtracted from the lifecycle results of cellulosic ethanol production.

### 2.4.7.5 Brazilian Sugarcane Ethanol

Under the imported sugarcane ethanol cases we updated process energy use assumptions to reflect anticipated increases in electricity production for 2022 based on recent literature and comments to the proposal. One major change was assuming the potential use of trash (tops and leaves of sugarcane) collection in future facilities to generate additional electricity. The NPRM had only assumed the use of bagasse for electricity generation. Based on comments received, we are also assuming marginal electricity production (i.e., natural gas) instead of average electricity mix in Brazil which is mainly hydroelectricity. This approach assumes surplus electricity will likely displace electricity which is normally dispatched last, in this case typically natural gas based electricity. The result of this change is a greater credit for displacing marginal grid electricity and thus a lower GHG emissions profile for imported sugarcane ethanol than that assumed in the NPRM. We also received public comment that there are differences in the types of process fuel e.g. used in the dehydration process for ethanol. While using heavier fuels such as diesel or bunker fuel tends to increase the imported sugarcane ethanol emissions profile, the overall impact was small enough that lifecycle results did not change dramatically. We describe these changes in further detail below.

In Brazil, the majority of mills are configured to produce both sugar and ethanol simultaneously. To simplify the lifecycle analysis, we assumed that a sugarcane ethanol mill is operated with 100% feed for ethanol production. In a sugarcane mill, sugarcane is cleaned, crushed, and the cane juice extracted. The juice is then treated to produce ethanol and/or sugar, depending on market demands. The stream for ethanol is fermented and distilled into hydrous ethanol. From there, there are two possibilities. Hydrous ethanol may be stored as the final product or dehydrated to anhydrous ethanol.

#### 2.4.7.5.1 Sugarcane Ethanol Process Energy Consumption

In Brazil, the majority of energy used at the sugarcane ethanol facility is supplied by burning bagasse, the fiber material leftover after extracting cane juice. The bagasse is combusted in a boiler to produce steam and generate electricity to meet internal demands as well as export surplus electricity to the grid. A smaller portion of energy is required for chemical and lubricant use. We used a bagasse yield of 280 kg (with 50% moisture) per MT of sugarcane.

#### 2.4.7.5.2 Bagasse Combustion Emissions

We used the IPCC guidelines (2006b) and average emission factors of $CH_4$ and $N_2O$ from biomass combustion, as shown in Table 2.4-60.

**Table 2.4-60. Emissions per mmBTU Bagasse Burned**[613]

| Pollutant | g/mmBTU bagasse burned |
|---|---|
| $CH_4$ | 31.65 |
| $N_2O$ | 4.22 |

### 2.4.7.5.3 Chemical and Lubricant Use

We assumed that the chemicals and lubricants are similar to residual oil in terms of energy and emission profiles (see Table 2.4-61).

**Table 2.4-61. Energy used for Chemicals and Lubricants**[614]

| | 2005/2006 | Scenario 2020 |
|---|---|---|
| Energy Use (Btu/gal); 100% residual oil | 798 | 766 |

We further assumed a 10% allocation of residual oil to ethanol to account for lubricating oil that is used not as a combustion source but is lost during operation of the machinery in the production of ethanol.

### 2.4.7.5.4 Ethanol yields

Table 2.4-62 shows a summary of ethanol yields from several studies.

**Table 2.4-62. Ethanol yields in Sugarcane Mills**

| Year | L/MT | Source |
|---|---|---|
| 1996-1997 | 79.5 | Moreira & Goldemberg (1999) |
| 2000 | 85.4 | Assuncao (2000) |
| 2001 | 78.58 | UNICA-Carb Comments; 138.7 TRS/ton cane and 1.7651 kg TRS/L anhydrous |
| 2005 | 85 | OECD (2008) |
| Avg. 2006-2008 | 84.68 | UNICA-Carb Comments; 149.47 TRS/ton cane and 1.7651 kg TRS/L anhydrous |
| Avg. in 2002<br>Best | 86<br>91 | Macedo et al. (2004)<br>GREET default |
| 2006<br>“2020” | 86.3<br>92.3/129* | Macedo et al. (2008)<br>*Includes cellulosic ethanol |
| 2015<br>2025 | 100<br>109 | Unicamp, as noted in OECD (2008) |

### 2.4.7.5.5 Ethanol dehydration

Standard distillation leaves over 4% water in ethanol, requiring a second step in the process to remove water in order to obtain fuel grade anhydrous ethanol (>99.3 wt%).[615] The most important ethanol dehydration techniques used in the world industry include azeotropic distillation, dehydration on molecular sieves, and more recently, pervaporation or vapor permeation.[616] Azeotropic distillation uses a third component, typically benzene or cyclohexane, to remove the final water from ethanol. Molecular sieves use an adsorbent with a strong affinity for water and little affinity for ethanol. This allows for separation of water from the ethanol product. Most new ethanol plants today are built with molecular sieve dehydrators. Pervaporation is still a fairly new technology, however, there is potential for energy consumption savings, thus making the technology attractive for newly built facilities.[617]

Data was unavailable to determine the split of facilities using one type of dehydration process over the other for import into the United States. However, we collected data on the amount of energy required to dehydrate a gallon of hydrous ethanol into anhydrous ethanol using primarily molecular sieve technology, see Table 2.4-63.

**Table 2.4-63. Energy Required for Dehydration**

| BTU/gallon of anhydrous | Source/Details |
|---|---|
| 4,000 | Swain |
| 2,830-5665 | Vane[618] |
| 4,500 | Kawaitkowski[619] |
| 4186-5931 | CBEPG[620]; Fuel Oil (primarily diesel) |
| 5156-5210 | CBEPG[621]; Natural Gas |

As noted in Chapter 1, the majority of ethanol imported into the U.S. may preferentially come through the Caribbean Basin Initiative countries due to favorable economic conditions. As the public comments on our rule suggest, there are differences in the type of fuels burned to run the processes for dehydration. This depends on the location of the dehydration facility and the fuel choices available at those locations. Fuels used to run the dehydration process include bagasse, natural gas, #2 distillate (diesel fuel), and #6 oil (bunker fuel).[622]

For the final rule, we have assumed an average energy consumption for dehydration from fuel oil use of 5059 BTU/gallon anhydrous produced and 5183 BTU/gallon anhydrous produced if natural gas is used.

We received comment to include a pathway for the Caribbean Basin countries. We evaluated the pathway based on the type of fuel used for dehydration, either from fuel oil or from natural gas. For the NPRM we had already evaluated the Brazilian direct pathway assuming dehydration used bagasse as a fuel. We calculated 1) the additional emissions from burning fuel oil and natural gas instead of bagasse and 2) the emissions credit from not dehydrating in Brazil from bagasse (i.e. electricity is produced instead).

Assuming an electricity generation efficiency of 30% (the current Brazil industrial average) and the energy consumption for dehydration as 5059 BTU/gallon anhydrous and 5183 BTU/gallon anhydrous for fuel oil and natural gas, we calculated an electricity credit of 0.44 and 0.46 kWh/gallon anhydrous produced for fuel oil and natural gas, respectively. This electricity credit is assumed to displace electricity as it is produced in Brazil, i.e. marginal electricity produced from natural gas. See discussion of Brazilian electricity generation in the following section.

#### 2.4.7.5.6 Electricity generation in Brazil

In Brazil, there has been an increasing use of bagasse to generate enough steam and electricity to supply the whole mill energy demand while still producing electricity surpluses. Table 2.4-64 summarizes the current and anticipated electricity generated for Brazilian sugarcane facilities. As noted, this is highly dependent on the types of boilers used, and whether or not there is collection of sugarcane leaves and tops (trash). Average cogeneration surplus for all sugarcane mills in Brazil was 10.5 kwh/MT cane in 2008, and could increase above 100 kwh/MT cane with the utilization of trash.

For the final rule, we have chosen to model the low (40 kwh/MT cane) and high (135 kwh/MT cane) surplus electricity scenarios.

### Table 2.4-64. Electricity Surplus in Brazil under Various Conditions

| Year | Biomass Used | Kwh/MT cane | Source/Details |
|---|---|---|---|
| 2006 | Bagasse w/ surplus leftover | 9.2 | CTC (2006); 10% mills use high press boilers, 90% 21 bar/300 C |
| 2007 | Bagasse | 22.5/23 | UNICA/MME/COGEN-SP/GREET default |
| 2008 | Bagasse | 10.5 | Avg. for all UNICA members (124 mills) |
| 2008 | Bagasse | 40 | OECD (2008), one standard facility; 20% of 39 mills or 4% of all mills |
| 2008 | Bagasse | 25.16 | Avg. for 39 mills surveyed by UNICA |
| Current | Bagasse | 0-10 | Smeets (2008), Combustion, partial steam extraction turbine, 22 bar, -300C |
| Current | Bagasse | 40-60 | Smeets (2008), Combustion, partial steam extraction turbine, 80 bar, -480C |
| 2012 | Bagasse | 65 | COGEN-SP, Amounts contracted |
| Near-term | Bagasse | 75 | UNICA, Upgrading to high-pressure steam cycle generators, using all bagasse |
| 2020+ | Bagasse + 40% trash for cellulosic ethanol;<br>Bagasse + 40 % trash for electricity | 44<br>135 | Macedo (2008)<br>Mills at 65 bar/480 C, CEST systems; process steam consumption ~340 kg steam/tonne cane |
| Longer-term | Bagasse + 50% trash for electricity | 67-100 | Smeets (2008), Combustion, condensing steam turbine, 80 bar, -480C |
| 2020+ | Bagasse + 50% trash for electricity | 135-200 | Smeets (2008), Gasification, steam-injected gas turbine |

#### 2.4.7.5.6.1 Average Brazilian Grid Electricity versus Marginal Grid Electricity

We have factored in credit in our analyses for the excess electricity generated from the burning of bagasse and potentially trash in the future. This, however, is dependent on the type of electricity displaced. Several comments on our rule indicate that the cogeneration in Brazil should displace the marginal power supplier (i.e., thermoelectric power plants running on natural gas or heavy fuel oil) instead of average grid electricity (i.e., hydroelectricity).[623] See Table 2.4-65 for the Brazil average fuel mix in 2007.

**Table 2.4-65.**
**Brazilian average fuel mix for electricity generation in 2007**[624]

| Fuel | % |
|---|---|
| Petroleum | 2.83% |
| Natural Gas | 3.63% |
| Coal | 1.34% |
| Biomass | 3.47% |
| Nuclear | 2.54% |
| Hydro | 77.28% |
| Others | 8.94% |
| Total | 100.0% |

We believe the use of marginal grid electricity instead of average electricity is reasonable given that 1.) We are crediting on the basis of displacement 2.) Electricity produced at the sugarcane ethanol facility is always dispatched when a mill is operating and this allows for reduction of the use of other thermal power plants. Table 2.4-66 shows the average fuel mix for Brazil's operating margin in 2008.

**Table 2.4-66. Brazilian Grid Operating Margin average fuel mix for electricity generation in December 2008**.[625]

| Fuel | % |
|---|---|
| Petroleum | 3.63% |
| Natural Gas | 60.24% |
| Coal | 14.37% |
| Biomass | 0.00% |
| Nuclear | 18.99% |
| Hydro | 1.11% |
| Others | 1.65% |
| Total | 100.0% |

As natural gas is the predominant fuel use, we have chosen to assume that marginal electricity in Brazil will displace electricity derived from natural gas.

### 2.4.8 Fuel Transport

The greenhouse gas impacts associated with the transportation and distribution of biofuels depend the average distance the fuel is transported from the plant to the retail location and the mode of transport (barge, rail, truck, etc.). This section summarizes the assumptions used in this analysis to represent the transport of biodiesel, and domestic and imported ethanol. A recent release of GREET[626] was utilized to estimate the GHG emissions based on these assumptions.

### 2.4.8.1 Biodiesel

For biodiesel transport, GREET default values were used to represent the average distances biodiesel is transported by barge, pipeline, rail, and truck from the plant to the terminal where it is blended with petroleum-based diesel fuel. The percentage of fuel transported by each mode was chosen to be consistent with the cost analysis described in Chapter 4. These inputs are summarized in Table 2.4-67.

GREET default values were used to represent the transport of biodiesel from the terminal to the retail location. These defaults assume 100% of biodiesel shipped by truck a distance of 30 miles.

**Table 2.4-67. Biodiesel Assumptions for Transport from Plant to Terminal**

| Mode | % | Distance (miles) |
|---|---|---|
| Barge | 5% | 520 |
| Pipeline | 0% | 400 |
| Rail | 45% | 800 |
| Truck | 50% | 50 |

### 2.4.8.2 Corn and Cellulosic Ethanol

Oak Ridge National Laboratory (ORNL)[627] recently conducted a study that models the transportation of ethanol from production or import facilities to petroleum blending terminals by domestic truck, marine, and rail distribution systems. We used ORNL's transportation projections for 2022 under the EISA policy scenario to estimate the percentage of corn and cellulosic ethanol transported by each mode and the averaged distance traveled. These assumptions are summarized in Table 2.4-68. More details on the ORNL study and the transportation projections can be found in Sections 1.6 and 3.3.

Since the study did not address the transport of ethanol from the terminal to refueling station, we used the GREET default assumptions of 100% shipped by truck a distance of 30 miles.

**Table 2.4-68. Corn and Cellulosic Ethanol Assumptions for Transport from Plant to Terminal**

| Mode | % | Distance (miles) |
|---|---|---|
| Barge | 12% | 336 |
| Rail | 77% | 629 |
| Truck | 17% | 68 |
| Local Truck[PPPPPPP] | 83% | 6.5 |

### 2.4.8.3 Sugarcane Ethanol

This analysis accounts for the transportation of sugarcane ethanol within Brazil, en route to U.S. import facilities, and within the United States. GREET default values are used to represent the transport of ethanol from a production facility in Brazil to a Brazilian port. Specifically, we assumed that 50% of the ethanol is transported via pipeline and the other 50% by rail an average distance of 500 miles (for each mode).

The ethanol is then loaded onto ocean tankers for transport to the United States. As described in Chapter 1, we projected that 46% of imported ethanol in 2022 would be shipped directly from Brazil, while 54% would first be shipped to a country in the Caribbean Basin Initiative (CBI) and then to the United States. For the latter case, we assumed 20% would be imported from Costa Rica, 20% from El Salvador, 30% from Jamaica, 15% from Trinidad and Tobago, and 15% from the Virgin Islands (see Table 1.8-11). Table 2.4-69 summarizes EPA estimates for the average distance ethanol is transported by ocean tanker for each of these paths. For these estimates, we used EIA data on fuel ethanol imports from 1993 to August 2009[628] to determine the fraction of ethanol shipped to different U.S. ports from Brazil and the CBI countries. We estimated the average distance imported ethanol travels by ocean tanker, accounting for all of these paths, to be 7,348 miles.

We received comment that assuming ocean tankers bringing ethanol from Brazil to the United States return to Brazil empty is incorrectly attributing emissions of an ocean tanker's round trip to sugarcane ethanol[629,630]. We, therefore, assume that emissions from back-haul are negligible for this analysis.

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[PPPPPPP] The ORNL study includes a second transportation mode for trucks, called "Local Trucks", which transport ethanol from dedicated ethanol terminals to blending terminals. Ethanol that travels directly from a refinery to a petroleum blending terminal would not be transported by local truck.

**Table 2.4-69. Average Ocean Tanker Distances for Sugarcane Ethanol Transport from Brazil and CBI Countries to the United States**[QQQQQQQ]

| | Average distance to U.S. import facilities (miles) | Total distance, including distance from Brazil (miles) |
|---|---|---|
| Costa Rica | 3375 | 10398 |
| El Salvador | 3691 | 11011 |
| Jamaica | 2466 | 7393 |
| Trinidad & Tobago | 2766 | 6590 |
| Virgin Islands | 1702 | 5919 |
| Brazil (direct) | 6141 | 6141 |

Within the United States, ORNL's transportation projections were used to estimate the average distance sugarcane ethanol is transported from an import facility to a petroleum blending terminal and the percentage that travels by each mode. Table 2.4-70 summarizes transport assumptions for sugarcane ethanol from production facilities in Brazil to blending terminals in the United States. As with corn and cellulosic ethanol, we used the GREET default assumptions to represent the transport of sugarcane ethanol from the terminal to a refueling station. These assumptions were 100% shipped by truck a distance of 30 miles.

**Table 2.4-70. Sugarcane Ethanol Assumptions for Transport from Plant to Terminal**

| **Mode** | **%** | **Distance (miles)** |
|---|---|---|
| Pipeline (in Brazil) | 50% | 500 |
| Rail (in Brazil) | 50% | 500 |
| Ocean Tanker | 100% | 7348 |
| Barge (in U.S.) | 12% | 336 |
| Rail (in U.S.) | 77% | 629 |
| Truck (in U.S.) | 17% | 68 |
| Local Truck (in U.S.) | 83% | 6.5 |

### 2.4.9 Biofuel Tailpipe Combustion

Combustion $CO_2$ emissions for ethanol and biomass-based diesel were based on the carbon content of the fuel. However, over the full lifecycle of the fuel, the $CO_2$ emitted from biomass-based fuels combustion does not increase atmospheric $CO_2$ concentrations, assuming the biogenic carbon emitted is offset by the uptake of $CO_2$ resulting from the growth of new biomass. As a result, $CO_2$ emissions from biomass-based fuels combustion are not included in their lifecycle emissions results. Net carbon fluxes from changes in biogenic carbon reservoirs in wooded or crop lands are accounted for separately in the land use change analysis as outlined in the agricultural sector modeling above.

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[QQQQQQQ] Distances between ports were calculated using www.distances.com. For Brazil and CBI Countries, the following representative ports were used: Santos in Brazil, Puntarenas in Costa Rica, Acajutla in El Salvador, Kingston in Jamaica; Port of Spain in Trinidad and Tobago, and St. Croix in the Virgin Islands.

When calculating combustion GHG emissions, however, the $CH_4$ and $N_2O$ emitted during biomass-based fuels combustion are included in the analysis. Unlike $CO_2$ emissions, the combustion of biomass-based fuels does result in net additions of $CH_4$ and $N_2O$ to the atmosphere. Therefore, combustion $CH_4$ and $N_2O$ emissions are included in the lifecycle GHG emissions results for biomass-based fuels.

Combustion related $CH_4$ and $N_2O$ emissions for biomass-based fuels are based on EPA MOVES model results. The values used are shown in Table 2.4-71. $CO_2$ emissions from biofuels are shown for illustrative reasons, but as mentioned above are not included in the analysis because they are assumed to be offset by carbon uptake from plant growth.

**Table 2.4-71.**
**Tailpipe Combustion Emissions for Bio-Based Fuels**

|  | **$CO_2$** | **$CH_4$** | **$N_2O$** |
|---|---|---|---|
| **Fuel Type** | **(g/mmBTU)** | **(g/mmBTU)** | **(g/mmBTU)** |
| Ethanol | 75,250 | 269 | 611 |
| Biodiesel | 81,044 | 11 | 689 |

### 2.4.10 Other Indirect Impacts

In the analysis of the proposed rulemaking the Agency conducted a study of the U.S. energy sector impacts of increased biofuel production. Using an EPA version of the Energy Information Administration’s National Energy Modeling System (NEMS) we attempted to determine the effects of biofuel production energy use, for example increased natural gas use for corn ethanol production and the impact that has on natural gas and other fuel sources price and use. The EPA-NEMS is a modeling system that simulates the behavior of energy markets and their interactions with the U.S. economy by explicitly representing the economic decision-making involved in the production, conversion, and consumption of energy products.

There were several problems encountered with the modeling done for the proposal, mainly in trying to isolate the impacts of a specific fuel and of the specific impact of biofuel energy use so the results were not used in the analysis. However, we indicated that we would continue exploring this modeling for the final rule.

Therefore, for the final rule we created a scenario in EPA-NEMS to simulate the RFS2 volumes, reaching 31.8 billion gallons of biofuels production in 2022. This scenario was compared to AEO 09, which estimated 13.8 billion gallons of biofuel production. This allowed us to see the energy system impacts of an increase in renewable fuels of 18 billion gallons.

The increase in renewable fuels supply triggered a decrease in gasoline demand. This led to a 0.73 million barrel per day decrease in crude oil imports and a 0.18 million barrel per day decrease in refined product imports. As a result of declining demand, crude oil prices decreased from $117.11/barrel to $116.43/barrel and petroleum product prices also decreased slightly. In addition, prices for natural gas and electricity declined significantly. The only price increases were a $0.10/mmbtu increase in the price of motor gasoline and a $1.49/mmbtu increase in the price of E85.

The overall $CO_2$ impact was a 34,736 grams $CO_2$ decrease for each mmbtu increase in renewable fuels over the baseline, or -34,736 grams $CO_2$/mmbtu. Reduced consumption of gasoline, diesel, and still gas (for refining) resulted in an overall decrease in emissions of 86.6 mmt $CO_2$. This decrease in emissions was partially offset by natural gas consumption for production of renewable fuels and by increased coal consumption for power generation, yielding an overall decrease in the domestic energy sector of 61.5 mmt $CO_2$.

The EPA-NEMS results were used in part to estimate the crude oil import reductions from the increased renewable fuel volumes mandated by this rulemaking, as discussed in Chapter 5. However, we have not used this analysis at this point in calculations of renewable fuel threshold analysis or for the overall rule impacts because of double counting issues regarding GHG emissions sources.

The final rule EPA-NEMS analysis eliminated some of the problems with the proposal modeling by considering a larger increase in biofuels consumption and by not specifically trying to isolate the impacts of one type of fuel. However, there were still issues with how this analysis compares to the other lifecycle modeling work conducted for this rulemaking. The main issue is double counting between the EPA-NEMS analysis and our lifecycle work. Both account for renewable fuel production energy use, which is difficult to separate in the EPA-NEMS modeling (especially for purchased electricity). Both also account for gasoline and diesel fuel reduction, both end use and refining energy. This is also difficult to back out of the EPA-NEMS modeling. Therefore, it is difficulty to isolate only the secondary or energy sector impacts that are not already covered elsewhere. There is also the issue that the EPA-NEMS model is only domestic and does not capture any potential international energy sector impacts. We will continue to study this modeling as part of any ongoing work on biofuel analysis.

### 2.4.11 Other Modeling Approaches Considered

#### 2.4.11.1 Analysis with the GTAP Model

The Global Trade Analysis Project (GTAP) model is an economy-wide multi-region general equilibrium (GE) model coordinated by the Center for Global Trade Analysis at Purdue University. GTAP is a publicly available global model that was originally developed for addressing international agricultural trade issues. An advantage of GE models such as GTAP is that they take into account how changes in U.S. biofuel policies affect world prices, output, and trading patterns for a wide variety of commodities that extend beyond the agricultural sector. The GTAP data base is peer reviewed and updated triannually. The GTAP databases and versions of the model are widely used internationally by a large modeling community.[631] Since its inception in 1993, GTAP has rapidly become a common "language" for many of those conducting global economic analysis. For example, the WTO and the World Bank co-sponsored two conferences on the so-called Millennium Round of Multilateral Trade talks in Geneva. Here, virtually all of the quantitative, global economic analyses were based on the GTAP framework. The use of the GTAP data base and model has been increasing with the growing research interests in international trade policies, energy policies, and climate change policies.

Because GTAP is publicly available, there are numerous versions of the GTAP-based model. However, the GTAP Center has a peer review process which includes replication of results by independent scientists. Those versions of GTAP which have been through this process, including the versions used in this analysis, qualify as peer-reviewed, published models.

The GTAP Version 6 data base divides the global economy into 57 sectors and 87 regions, some of which have been aggregated in the results presented below for simplification. Over the past few years, several improvements have been made to the model. For example, a version of the model was developed to explicitly account for substitution between energy commodities.[632] Another version of the model was developed to explicitly model global competition among different land types (e.g., forest, agricultural land, pasture) and different qualities of land based on the relative value of the alternative land-uses.[633] More recently the above two frameworks were combined and modified to include biofuel substitutes for gasoline and diesel.[634] The California Air Resources Board (CARB) has utilized the GTAP model to assess biofuel land use impacts in its recent rulemaking on a Low Carbon Fuel Standard. Current research is ongoing to add additional detail on the biofuels market, some of which is described below.

#### 2.4.11.1.1 Partial Equilibrium versus General Equilibrium Modeling

Although we have used the partial equilibrium (PE) models FASOM and FAPRI-CARD as the primary tools for evaluating whether individual biofuels meet the GHG thresholds, as part of the peer review process, we explicitly requested input on whether GE models should be used. None of the commenters recommended using a GE model as the sole tool for estimating GHG emissions, although several reviewers discussed some of the advantages of GE models compared to PE models. For example, GTAP captures the interaction between different sectors of the economy. As discussed by the peer reviewers, the link between the agricultural and the energy markets has become increasingly important given the increased production of renewable fuels from agricultural products. Higher crude oil prices and policies to increase demand for renewable fuels have increased the linkages between these two markets, and increased renewable fuel production could have impacts on food security, international trade, and natural resources. These linkages can be captured in a sufficiently detailed GE model. The literature on economic modeling of biofuels suggest that for analyzing the long-term consequences on consumption, the GTAP model is a suitable economic tool to link energy and crop demand.[635]

One of the major benefits of using the GTAP model is that it explicitly models land-use conversion decisions. GTAP is designed with the framework of predicting the amount and types of land needed in a region to meet demands for both food and fuel production. The GTAP framework also allows predictions to be made about the types of land available in each region to meet the needed demands, since it explicitly represents different land types within the model.

In theory, a detailed GE model would be the ideal modeling framework. However, as described in other sections, there is currently no single model that captures all of the necessary aspects of lifecycle GHG emissions. In their current state of development, GE models alone, including GTAP, are not yet adequate for determining whether biofuels meet greenhouse gas emission thresholds for the following reasons.

First, most GE models do not contain the level of detail in the agriculture sector required to determine acreage and production changes by crop by region. Because GE models must account for all sectors of the global economy, simplifications have been made to capture many of the complex interactions. Therefore, some level of aggregation of regions, markets, and relationships is necessary. For example, GTAP contains only an aggregated "coarse grain" crop and does not provide information specific to corn acres and production. Similarly, GTAP contains only a generic oilseed crop and does not include information about soybean-specific production and usage data. As a result, palm oil and soybean oil are aggregated into a single sector, even though these two crops may have very different resource implications. Furthermore, the GTAP model does not yet contain cellulosic feedstocks such as switchgrass or corn stover.

Second, the version of GTAP used for biofuels is a static model that does not currently capture changes over time. (The dynamic GTAP model has yet to be modified for use in energy and land use issues.) The GTAP Version 6 data base, the version used for this analysis, is based on a 2001 world economy. The model has been validated against historical data from 2001 through 2006 and the resulting 2006 baseline is used for biofuels policy analyses. Due to its static nature, the GTAP biofuels model is not able to project the time path of the global economy through 2022, which is the timeframe of primary interest for this rulemaking. Since we expect trends such as increases in crop yields, oil prices, population growth, and GDP growth to continue in the future, it is essential that our modeling framework captures these dynamics.

Third, the GTAP model relies on differences in land rental rates to determine which lands will be converted to crop land as a result of increasing biofuel demand. Land rents are the indicators of productivity in each agro-ecological zone (AEZ). In the GTAP data base, Lee *et al.* (2009) determine land rents for cropland, pasture, and forest based on the yearly economic activity in a given AEZ.[636] By definition, land rents are largest in those AEZs where high value crops are grown. For determining land rents for the livestock sector, Lee *et al*. draw on the direct competition between these sectors with grazing land. For computing livestock sectors' land rent, Lee *et al.* use the average coarse grain yield in each AEZ (as there is no 'forage crop' sector in the GTAP data base) and multiply it by the pasture land cover hectares. Finally, Lee *et al.* compute the forest land rents by using information on timberland land rent and timberland area offered by Sohngen *et al.* (2009). One of the major limitations of this methodology is that unmanaged land, which represents approximately 34% of the land cover in the GTAP model, is not allowed to be brought into productive use (e.g., as pasture). The unmanaged land category in GTAP varies significantly across countries, but includes a substantial amount of shrubland, savanna, and grassland in many areas (e.g., 20% of the land area covered in Brazil and 40% of the land area covered in Argentina).

Fourth, although most of the behavioral parameters (e.g., international trade elasticities, agricultural factor supply) contained in GTAP are estimated econometrically, some of the key relationships are actually based on literature reviews, theory, and analyst judgment.[637] In theory, all the relationships in the model could be based on regionally-specific empirical data, however in practice this is often not the case. For example, the elasticity of transformation (i.e., the measure of how easily land can be converted between forest, pasture, and crop land) is an important parameter in the GTAP model. However, the global value used for this parameter relies on a single study that is based on U.S. data. Ideally, this value would be based on empirical data that is specific to each region in the model, since this response is likely to be different in different parts of the world.

Given the relative advantages of PE and GE models, we opted to use the GTAP model to provide another estimate of the quantity and type of land conversion resulting from an increase in corn ethanol and biodiesel given the competition for land and other inputs from other sectors of the economy. These results help to bracket the land use changes estimated by the FAPRI-CARD model.

#### 2.4.11.1.2 Comparison of GTAP and FAPRI-CARD Model Results

One of the advantages of the GTAP model is that it is an open source framework in which many different groups can conduct research simultaneously. As a result, there are many different "variations" of the GTAP model in existence, each of which is in a different state of peer-review. As researchers publish papers using their updated variation of the model, the programming code is generally published so that others may benefit from these model enhancements. For our corn ethanol analysis, we used a slightly modified version of the GTAP model that was extensively reviewed as part of the California Air Resources Board (CARB) for their Low Carbon Fuel Standard rulemaking.[638] However, one of the criticisms of the CARB analysis was the treatment of biodiesel byproducts. New research by Taheripour et al[639] has been recently conducted to explicitly model the production and substitution of oilseed meal as a byproduct of biodiesel production, which provides a more accurate representation of the soybean biodiesel market interactions. We have therefore used this variation of the GTAP model to conduct the soybean biodiesel analysis.[RRRRRRR]

We made three revisions to the CARB modeling inputs to make our corn ethanol and soybean biodiesel analysis more consistent. First, we changed the elasticity of crop yields with respect to area expansion. This parameter is a measure of how much crop yields will decrease as agriculture expands onto new land. In theory, the most productive agricultural lands are already in use, therefore expanding production into more marginal lands will result in a decrease in average crop yields. CARB used a factor of 0.5 in its analysis, which implies that each new acre of land is only 50% as productive as an existing acre of land. However, more recent analysis suggests that a value of 0.66 may be more appropriate, indicating that for every two acres of additional cropland needed, three acres of forest or pasture lands must be converted to new cropland.[640] Therefore, we have used 0.66 as the elasticity for our analysis of corn ethanol and biodiesel. Second, we adjusted the 2006 baseline ethanol and biodiesel production levels. Our modified version of the CARB model used in this study has 4.25 BG of corn-ethanol and 0.14 BG of biodiesel in the 2006 baseline. Finally, since our baseline included a crude oil price shock from $25/barrel in 2001 to $60/barrel in 2006, our biofuel scenarios started with a $60 oil price laden economy versus $25 in the CARB biofuel scenarios.

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[RRRRRRR] This version of the model was in press at the time of this rulemaking. As a result, the code was not available to use this variation of the GTAP model for the corn ethanol analysis, hence our use of the CARB model for the corn ethanol analysis.

Because the GTAP model is static, it was not possible to analyze the exact same corn ethanol and soybean biodiesel scenarios in GTAP that we analyzed using the FAPRI-CARD model. Therefore, we analyzed a 2 billion gallon increase in corn ethanol over the 2006 updated baseline level of 4.25 BG. Similarly, our soybean biodiesel shock imposed a 1 BG increase in U.S. soybean biodiesel production over the 2006 updated baseline level of 0.14 BG. In order to compare the results of the GTAP model to the FAPRI-CARD model, we then "normalized" the land cover changes to obtain an acreage change per BTU of the biofuel shock. Other simplifications were also required. For example, GTAP aggregates regions differently than FAPRI-CARD, therefore we have summarized the results into larger regions for comparison purposes. Despite these shortcomings and compromises in trying to compare results from GTAP and FAPRI-CARD, the relative impacts on land use we believe are informative in that GTAP confirms that there are significant impacts on international land use due biofuel production from food and feed crops.

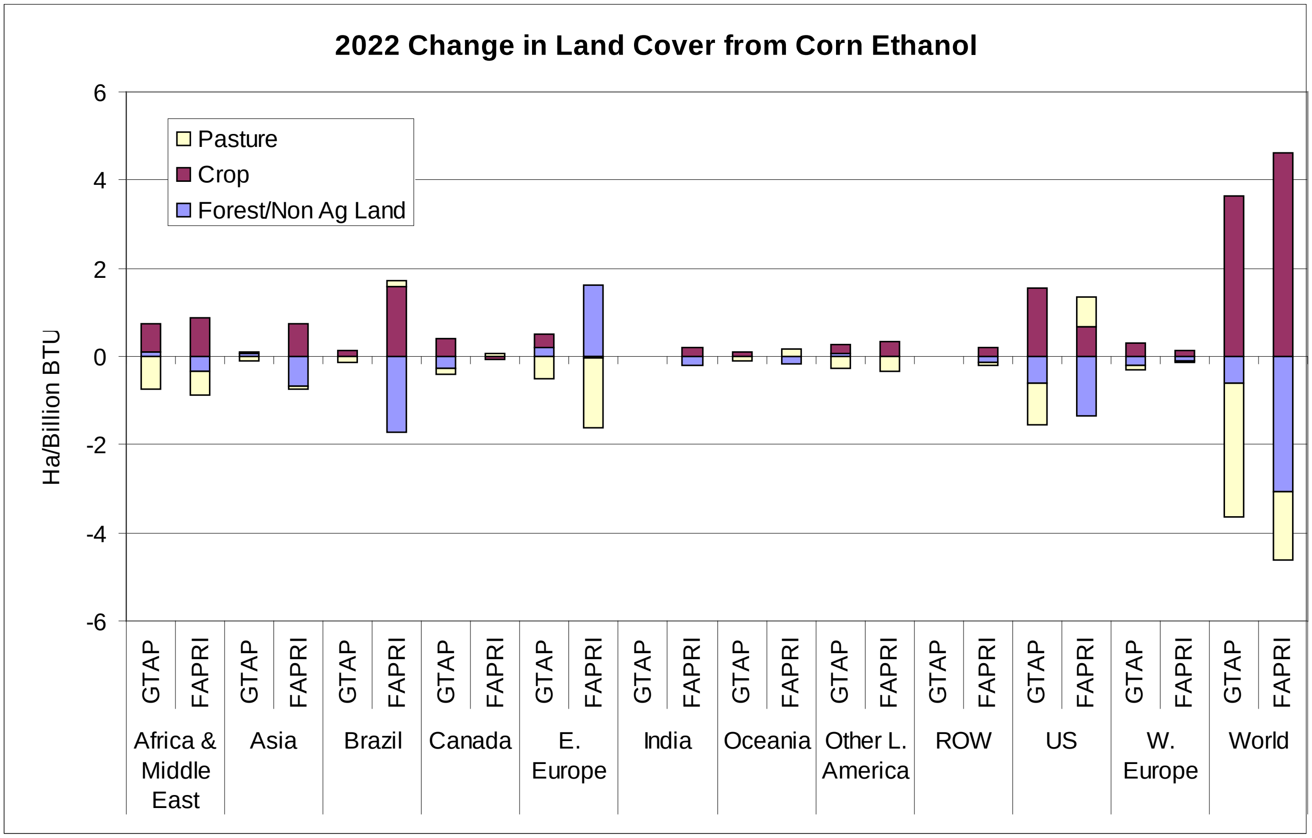
#### 2.4.11.1.3 Comparison of GTAP and FAPRI-CARD Corn Ethanol Results

Despite differences in the way the corn ethanol scenarios were implemented, the quantity of total acres converted to crop land projected by GTAP were similar in scale to the changes projected by the FAPRI-CARD results when normalized on a per BTU basis. However, the mean estimates for land converted to crops projected by GTAP were smaller than the changes predicted by FAPRI-CARD, which is most likely due to several important differences in the modeling frameworks.

First, the GTAP model incorporates a more optimistic view of intensification options by which higher prices induced by renewable fuels results in higher yields, not just for corn, but also for other displaced crops. Second, the demands for other uses of land are explicitly captured in GTAP. Therefore, when land is withdrawn from these uses, the prices of these products rise and provide a certain amount of "push-back" on the conversion of land to crops from pasture or forest. Third, none of the peer-reviewed versions of GTAP currently contain unmanaged land, thereby omitting additional sources of land. In Figure 2.4-46 and Figure 2.4-47, the GTAP results assume all land that is not crop or pasture is forest. However, the FAPRI-CARD results allow land that is not crop or pasture to come from a variety of other non agricultural land such as grassland, savanna, shrubland and wetlands. The disaggregation of FAPRI-CARD "non ag land" is described in more detail in Section 2.4.4.2.5.

Although the global aggregated results are similar, the regional distribution of land cover change varies between the FAPRI-CARD and GTAP models. Both models predict similar changes in India, Oceana, non-Brazilian Latin America, and Africa/Middle East. However, the FAPRI-CARD model predicts significant increases in crop acres in Brazil and Asia, whereas the GTAP model projects limited land use change in those regions. In contrast, the GTAP model projects more crop acre conversion in the U.S. for corn ethanol scenarios. These differences are due to the result of contrasting international trade structures in the models. FAPRI-CARD includes more flexible agricultural trade patterns, and projects agricultural expansion in lower cost of production regions that show the greatest capacity for expansion. In contrast, GTAP tends to maintain existing trade patterns, so it is more likely to project changes in countries that are already major trading partners of the U.S. A formal econometric analysis of these differences is offered in Villoria and Hertel (2009).[641]

**Figure 2.4-46. Changes in Land Cover from an increase in Corn Ethanol**

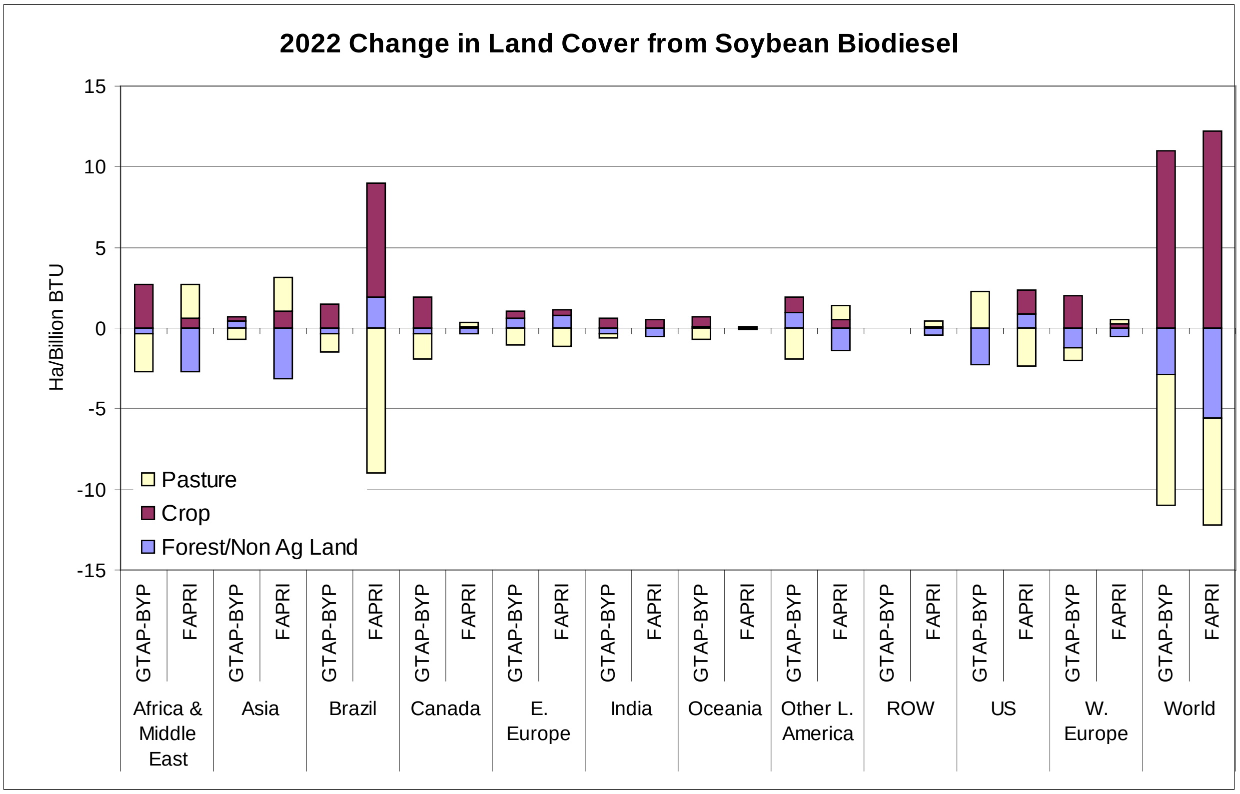


### 2.4.11.1.4 Comparison of GTAP and FAPRI-CARD Soybean Biodiesel Results

In the soybean biodiesel analysis, the total increase in crop acres aggregated at the global level is similar in the FAPRI-CARD and GTAP results. As with the corn ethanol analysis, the regional distribution of these changes also varies. While both models predict similar impacts in Eastern Europe and India, once again the FAPRI-CARD model estimates much larger increases in crop acres in Brazil than the GTAP model. The GTAP model estimates a larger increase in crop acres in Africa and the Middle East and Canada compared to the FAPRI-CARD model. The changes in the U.S. are also different. Whereas the FAPRI-CARD model predicts some increase in crop and forest acres, the GTAP model predicts almost no change in crop acres. Instead, the GTAP model estimates that there will be an increase in pasture land as a result of increasing soybean biodiesel in the U.S. These differences appear to be based on the fact that the GTAP model assumes the price of soybean meal will decrease significantly as a result of the increase in soybean crushing required to produce oil for biodiesel. GTAP projects that the decrease in soybean meal prices will lead to increased beef production, which requires additional grazing land to complement the use of soybean meal for beef production. In contrast, the FAPRI-CARD model assumes that increased biodiesel production will lead to a decrease in U.S.

beef production, since the relative price of non-grazing animals (e.g., poultry and pork) will decrease more than the price of beef as a result of lower soybean prices. As a result, U.S. beef production and pasture land decreases in FAPRI-CARD and we believe this is a more rational outcome.

**Figure 2.4-47. Changes in Land Cover from an increase in Soybean Biodiesel**



2.4.11.1.5 Systematic Sensitivity Analysis with the GTAP Model

As mentioned above, there are several parameters that have a significant impact on the amount and type of land conversions resulting from an increase in biofuel demand. Due to uncertainty in the past and future values of these parameters, it is possible to use the GTAP model to perform a systematic sensitivity analysis (SSA). Traditional uncertainty analysis relies on a Monte Carlo simulation which solves for equilibrium conditions using a large number of draws from the underlying distribution of potential parameter values. However, Monte Carlo analysis is not generally practical for a large CGE model. Instead, previous researchers have performed a SSA with Gaussian Quadrature numerical integration. This methodology uses a small number of draws from the distribution of random variables to provide a robust range of results that can be used to develop a confidence interval around the mean estimates.[642]

In our analysis, the parameters that appear to have the largest impact on the results include the elasticity of crop yields, the elasticity of harvested acreage response, and the elasticity of transformation across cropland, pasture, and forest land. The elasticity of crop yields, often referred to as "price induced yields" is the measure of how much a particular crop's yield will increase in response to an increase in the price of that crop. The larger the value of the elasticity, the more the increase in yields is expected to increase in response to higher prices. In our analysis, we used Keeney & Hertel's recommended mean value of 0.25, which indicates that a 1% increase in coarse grain prices leads to a 0.25% increase in coarse grain yields.[sssssss] For the SSA, the range of values analyzed was from a low end of 0 (i.e., yields do not respond to price changes) to a high end of 0.5.[643] The elasticity of transformation of crop land is a measure of how easily crop acres can be converted between types of crops. For example, the larger the value, the more easily coarse grain acres can be converted to oilseed acres in response to a change in land rental rates. For our analysis, we used a mean value of -0.5 with a lower bound of -0.1 and an upper bound of -1.0.[644] The elasticity of transformation of land supply is a measure of how easily land can be converted between land cover types (e.g., from forest to crop or pasture). The larger the value of this elasticity, the more land will be converted to different types of land cover in response to changes in relative land rental rates. For our SSA, we used a mean value of -0.2, with a lower range of -0.04 and an upper range of -0.36.[645]

#### 2.4.11.1.5.1 GTAP Systematic Sensitivity Analysis for Corn Ethanol

As shown in Table 2.4-48, there is a wide range of potential values for the amount of crop cover changes by region. However, it is important to note that for almost all regions, the range of potential values does not cross the X-axis. Thus, we interpret these results to imply that there is a statistically significant change in crop acres in most of the GTAP regions as a result of the increase in corn ethanol. Similarly, as shown in Figure 2.4-49, the range in potential values of pasture cover does not generally cross the X-axis for most of the regions. We therefore conclude that the decrease in pasture acres is statistically significant in most regions as a result of the increase in corn ethanol. Finally, Figure 2.4-50 shows that the mean estimate for some regions show an increase in forest acres, while other regions show a decrease in forest acres. Again, the confidence intervals around these estimates do not generally cross the X-axis, therefore we interpret these results to be statistically significant.

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[sssssss] As discussed in RIA Chapter 5, our FAPRI-CARD projections include disaggregated price-induced yield elasticities that vary by region, crop and time period.

Figure 2.4-48. Crop cover change due to U.S. corn-ethanol production (million acres)

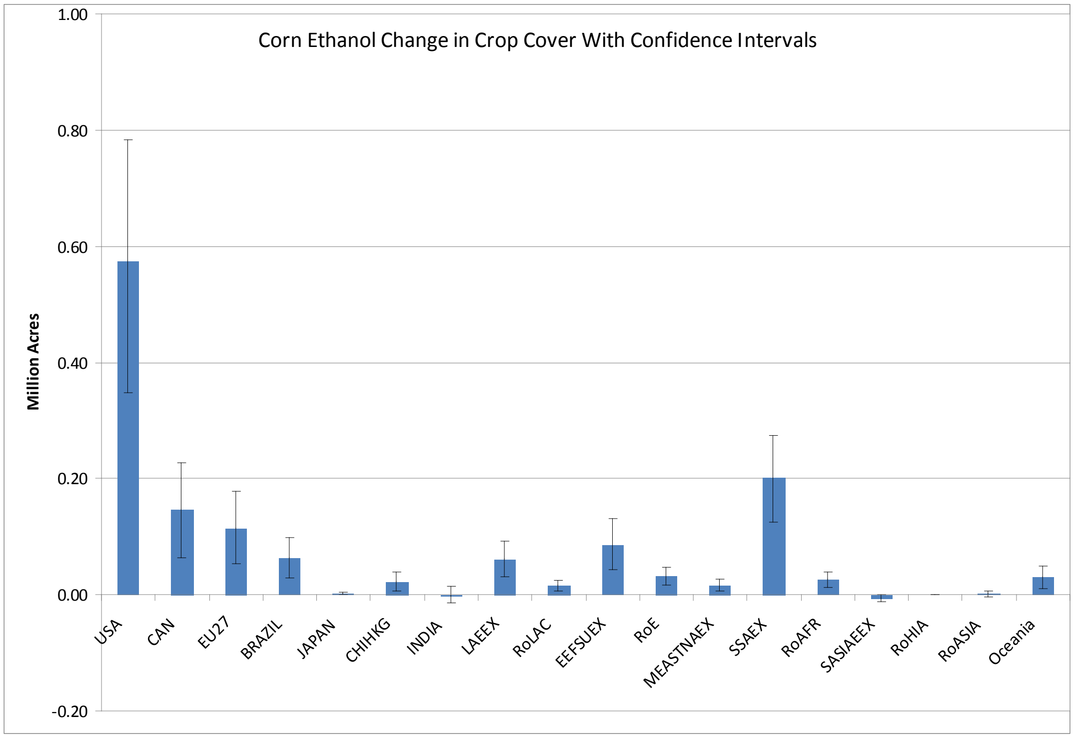


Figure 2.4-49. Pasture cover change due to U.S. corn-ethanol production (million acres)

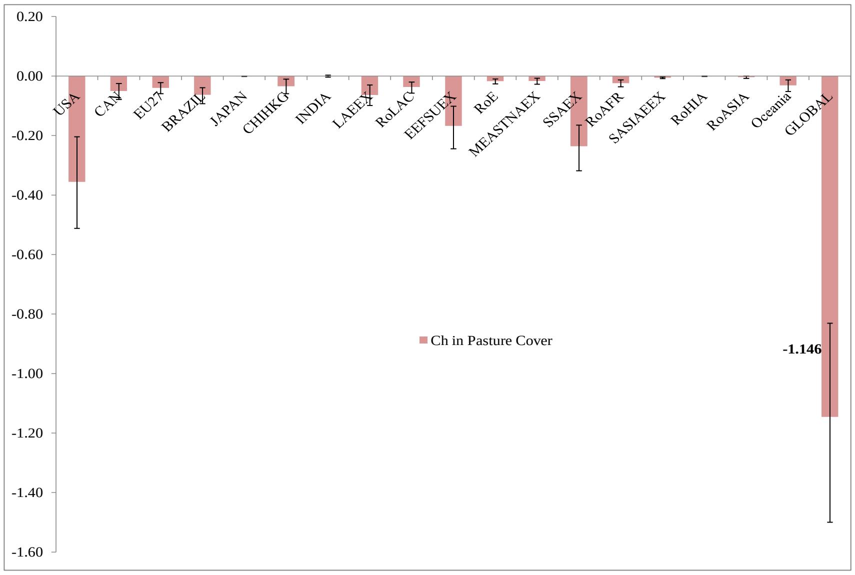
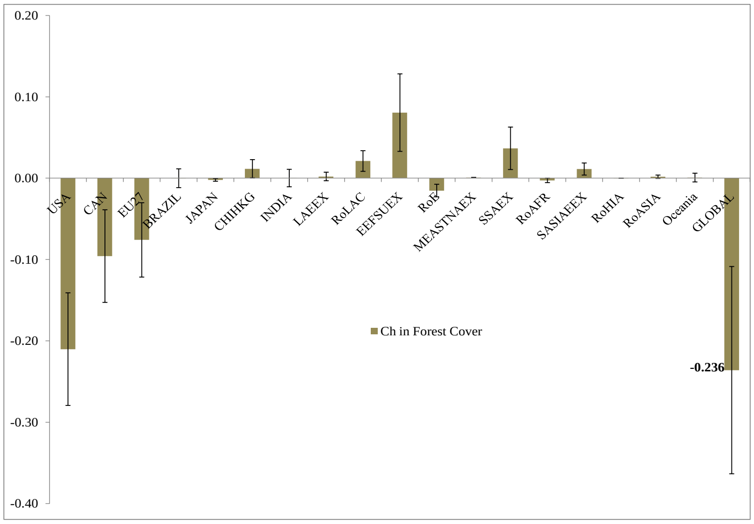


**Figure 2.4-50. Forest cover change due to U.S. corn-ethanol production (million acres)**



### 2.4.11.1.5.2 GTAP Systematic Sensitivity Analysis for Soybean Biodiesel

Similar to the corn ethanol results, the SSA for biodiesel generally shows that the land cover changes are statistically significant for the crop, pasture, and forest acre changes predicted by GTAP. As shown in the following figures, most of the confidence intervals do not cross the X-axis, therefore indicating that that the results are robust.

Figure 2.4-51.  Crop cover change due to U.S. biodiesel production (million acres)

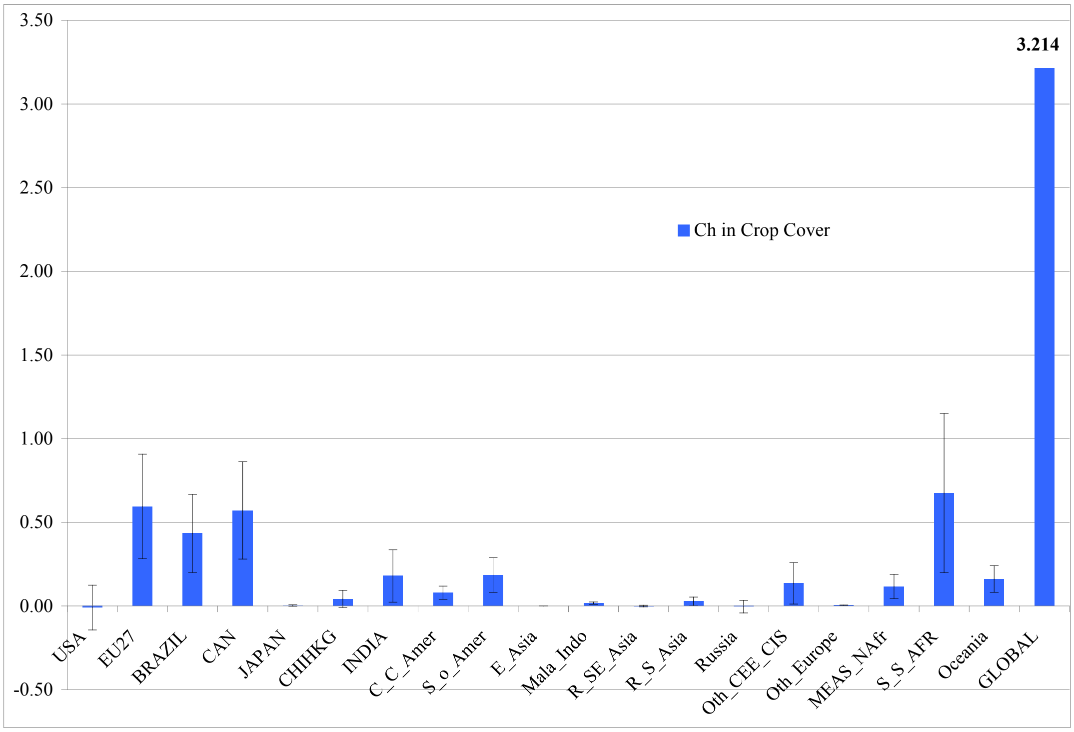


Figure 2.4-52.  Pasture cover change due to U.S. biodiesel production (million acres)

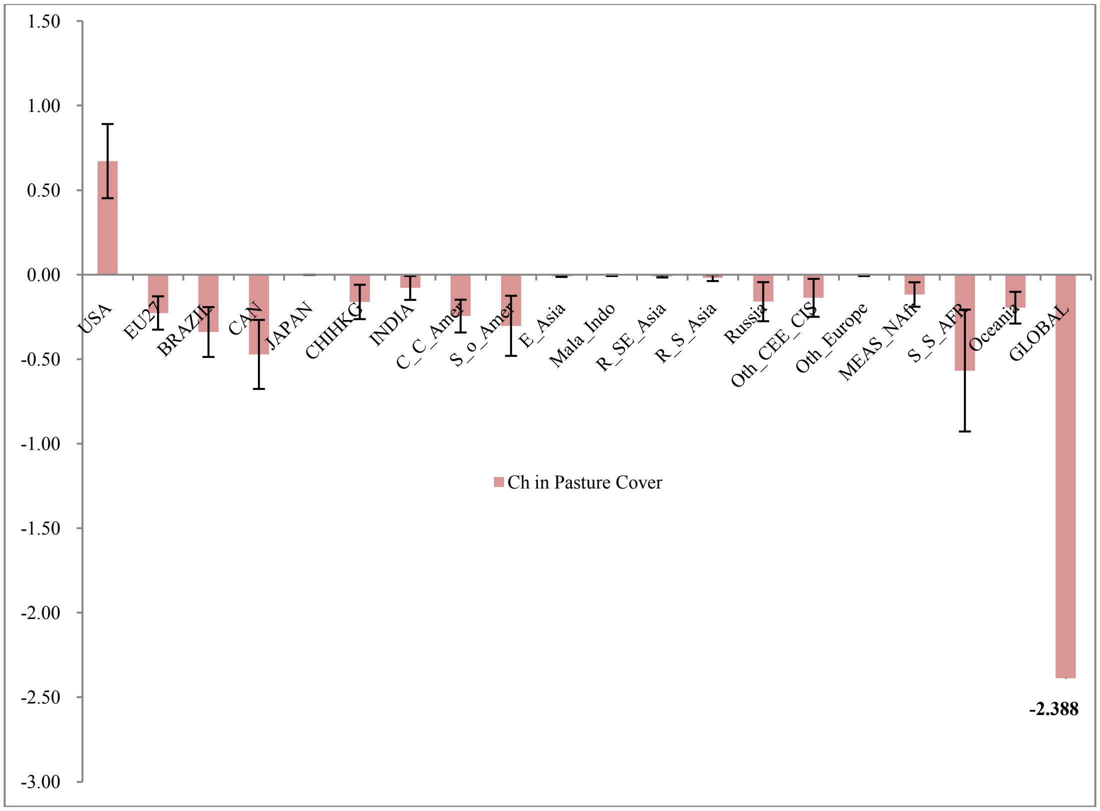
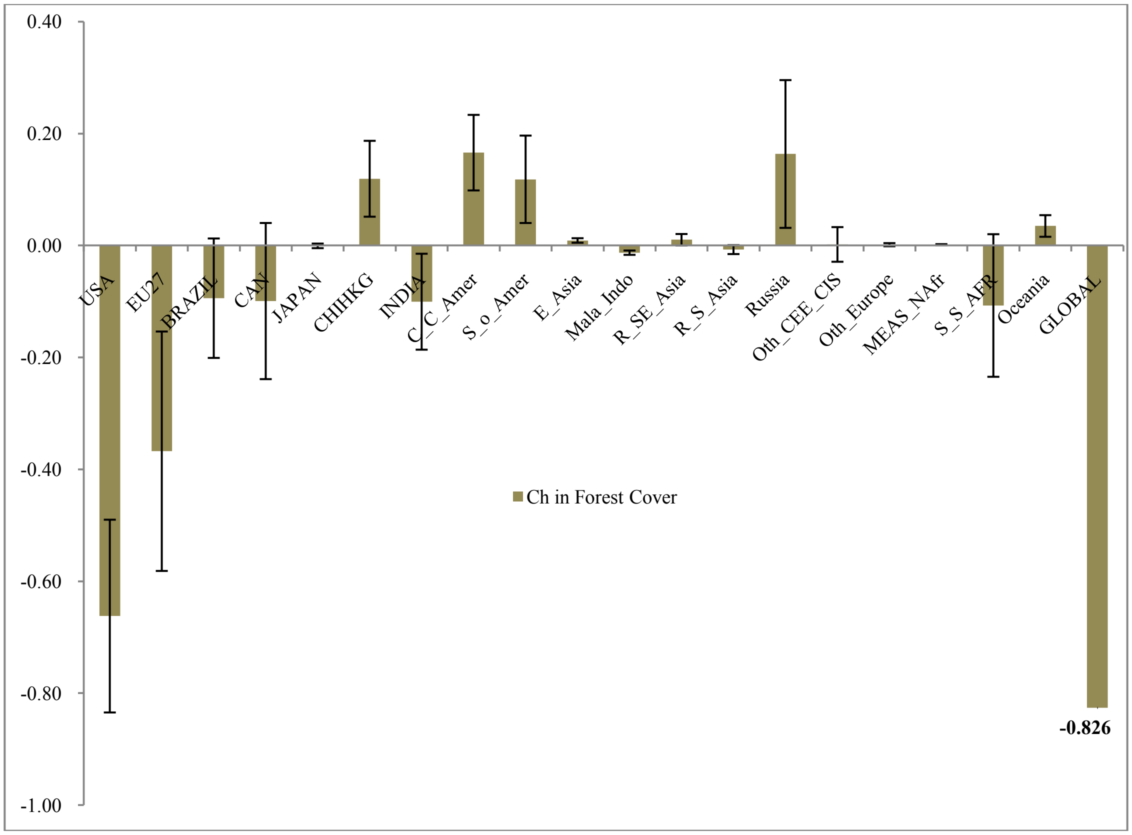


**Figure 2.4-53. Forest cover change due to U.S. biodiesel production (million acres)**



## 2.4.11.2 Evaluation of International Land Conversions with Higher Resolution Satellite Data

EPA worked with remote sensing experts from Integrity Applications Inc. (IAI) to analyze higher resolution satellite imagery in regions that factored prominently into our land use change analysis. The purpose of this analysis was to compare the Version 5 MODIS imagery with 500-m resolution to an imagery data set with much higher resolution. As discussed in preamble Section V and above, EPA only uses satellite imagery to evaluate recent land use change patterns, which are the results of many factors. Satellite imagery is not used to determine the amount of land conversion caused specifically by biofuel production. As discussed below, we found that the higher resolution LandSat data set with 30-m resolution provided similar results.

Based on resources and data availability, three regions were chosen for analysis: Brazil, India and the Indonesian island of Sumatra. Brazil was chosen because it was, and remains, the country with the largest agricultural land use response in our modeling of the indirect impacts of U.S. biofuel consumption. In the proposed rule analysis, India was the most important region in Asia. Based on modeling updates, the response in India was much smaller in our final rule analysis. However, it is still a good country to analyze with higher resolution data because it is a major agricultural producer with crops and land cover types distinct from what is found in Brazil. Finally, Indonesia was chosen because it is a major producer of palm oil in a region with peat soils. We narrowed our focus to the island of Sumatra because satellite imagery for Indonesia suffered from significant cloud cover problems.

Our high resolution analysis relied on the Landsat Global Land Surveys for the years 2000 and 2005; these Global Land Surveys are mosaics (i.e., compilations) of multi-spectral digital images produced to represent the entire earth during the growing season of a specific year. For optimal comparison of land cover categories, the MODIS data set was used as training data to classify the raw Landsat imagery. Table 2.4-72 summarizes the characteristics of the data used.

**Table 2.4-72. Characteristics of Satellite Data for High Resolution Analysis**

| | **Landsat** | **MODIS** |
|---|---|---|
| Data use | IAI: land use classification and change detection | IAI: training data to classify raw Landsat data<br>Winrock: land use classification and change detection |
| Data source | Landsat Global Land Survey | MODIS V5[646] |
| Years covered | Effectively 2000 and 2005 | 2001, 2005 and 2007 |
| Temporal resolution | +/- 3 years; data acquired every 16 days | Every one to two days |
| Spatial resolution | 30-m | 500-m |
| Public Availability | US Geological Survey (USGS) Archive[647] | LP DAAC Data Pool[648] |

By calibrating the land cover classification definitions to those used by MODIS, we converted the true color Landsat images into corresponding classification maps (see Figure 1). The color key for the classification map is provided below in Figure 2.4-54.

**Figure 2.4-54. Example of a true color Landsat image (left) and the corresponding land cover classification map (right)**

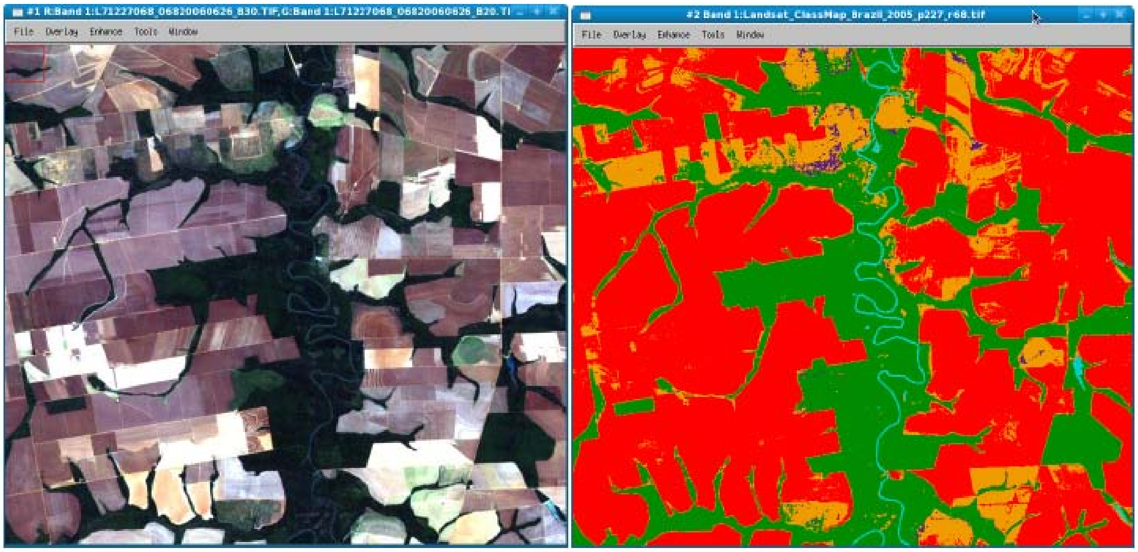


**Figure 2.4-55. Land categories and corresponding colors**

| Land Use Category | Color in Class Map |
|---|---|
| Forest | Dark Green |
| Shrubland | Yellow |
| Savannah | Orange |
| Grassland | Light Green |
| Cropland | Red |
| Natural/Mixed Vegetation | Purple |
| Wetlands | Cyan |
| Barren | Pink |
| Water | Blue |
| Urban/built-up | White |

Classification maps from 2000 and 2005 were compared to find areas where land changed from one category to another. For comparison with EPA's MODIS analysis, the resulting change matrices were aggregated by Administrative Unit and we analyzed the types of land converted to cropland. For most regions, the higher resolution data found deforestation rates somewhere in between the original and corrected MODIS data (see Section 2.4.4 for an explanation of the MODIS correction process). Validation data similar to the confusion matrix used to correct the MODIS data set was not available for the Landsat data, therefore it is difficult to directly compare these results. However, in general, the results do suggest that the resolution of the Version 5 MODIS data is adequate (i.e., provides similar results as higher resolution imagery), especially after it has been corrected with data validation procedures.

Figure 2.4-54 shows the share of deforestation from crop expansion in each region analyzed, and Table 2.4-73 includes all of the land types converted to cropland. The Indonesia results are omitted because of the cloud cover issues mentioned previously. More details about the Landsat data analysis are provided in a technical report by IAI available on the docket.[649]

**Figure 2.4-56. Share of Deforestation from Crop Expansion Measured with MODIS and Landsat Satellite Imagery**

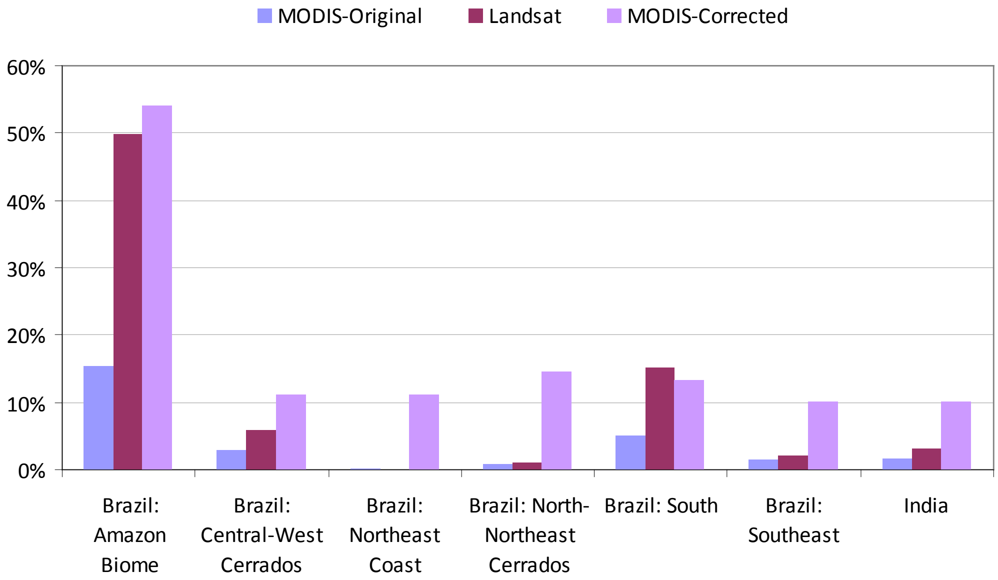


**Table 2.4-73. Types of Land Converted to Cropland by Data Source and Region**

| | | *Region* | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | Data Source | Brazil: Amazon Biome | Brazil: Central-West Cerrados | Brazil: Northeast Coast | Brazil: North-Northeast Cerrados | Brazil: South | Brazil: Southeast | India |
| Forest | Landsat | 50% | 6% | 0% | 1% | 15% | 2% | 3% |
| | MODIS-Corrected | 54% | 11% | 11% | 15% | 13% | 10% | 10% |
| Grassland | Landsat | 8% | 19% | 8% | 12% | 14% | 10% | 5% |
| | MODIS-Corrected | 8% | 26% | 19% | 16% | 23% | 18% | 21% |
| Mixed | Landsat | 11% | 20% | 28% | 14% | 55% | 53% | 27% |
| | MODIS-Corrected | 15% | 20% | 19% | 10% | 28% | 30% | 30% |
| Savanna | Landsat | 26% | 55% | 54% | 67% | 14% | 34% | 49% |
| | MODIS-Corrected | 20% | 36% | 41% | 49% | 29% | 36% | 19% |
| Shrubland | Landsat | 2% | 0% | 9% | 5% | 1% | 1% | 14% |
| | MODIS-Corrected | 2% | 6% | 8% | 9% | 6% | 6% | 17% |
| Wetlands | Landsat | 2% | 0% | 0% | 1% | 1% | 0% | 0% |
| | MODIS-Corrected | 1% | 0% | 0% | 0% | 0% | 0% | 1% |
| Barren | Landsat | 0% | 0% | 1% | 0% | 0% | 0% | 2% |
| | MODIS-Corrected | 0% | 0% | 1% | 1% | 0% | 0% | 2% |

## 2.5 Baseline Gasoline and Diesel Fuel

### 2.5.1 Background

Section 201 of the Energy Independence and Security Act (EISA) mandated that a baseline for gasoline and diesel fuel be established against which renewable fuels were to be compared:

> *The term 'baseline lifecycle greenhouse gas emissions' means the average lifecycle greenhouse gas emissions, as determined by the Administrator, after notice and opportunity for comment, for gasoline or diesel (whichever is being replaced by the renewable fuel) sold or distributed as transportation fuel in 2005.*

For the proposed rule, the Agency used the GREET model (Version 1.8b) to calculate the baseline GHG impacts of gasoline and diesel fuel production. However, we received numerous comments stating that GREET was not the best tool to use to calculate the petroleum baseline. Hence, to estimate the lifecycle GHG emissions associated with baseline gasoline and diesel transportation fuel for the final rule, we utilized the 2009 analysis performed by the National Energy Technology Laboratory (NETL), "Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels", which was specifically directed at establishing this 2005 baseline. NETL stated that the goal of their study was to "determine the life cycle greenhouse gas emissions for liquid fuels (conventional gasoline, conventional diesel, and kerosene-based jet fuel) production from petroleum as consumed in the U.S. in 2005 to allow comparisons with alternative transportation fuel options on the same basis (i.e., life cycle modeling assumptions, boundaries, and allocation procedures)." Furthermore, NETL stated that "[t]he study goals and scope were aligned to meet the definition of "baseline lifecycle greenhouse gas emissions" as defined in the Energy Independence and Security Act of 2007 (EISA 2007), Title II, Subtitle A, Sec. 201." Specific detail on NETL's analysis can be found in their report.[650]

### 2.5.2 Crude Oil Extraction

NETL determined the emissions associated with extraction and processing for crude oil and synthetic crude oil, natural gas liquids (NGLs), and unfinished oils as feedstocks to U.S. petroleum refineries and to foreign refineries producing gasoline and diesel imported by the U.S. in 2005.

#### 2.5.2.1 U.S. Refineries

The input of crude oil, natural gas liquids, and unfinished oils to domestic refineries was determined from EIA data and is summarized in Table 2.5-1 below.

**Table 2.5-1. Feedstock inputs to U.S. refineries**

| | Feedstock Input (thousand bbl/day) |
|---|---|
| Crude Oil | 15,220 |
| Natural Gas Liquids | 432 |
| Unfinished Oils (net) | 569 |

The crude oil mix to U.S. refineries was also determined from EIA data and is reflected in Table 2.5-2.

**Table 2.5-2. Crude oil imports to U.S. refineries**

| | U.S. Crude Oil Sources Production/Import as % of Refinery Crude Input (Year 2005, EIA) |
|---|---|
| U.S. Crude Oil | 33.8% |
| Canada Crude Oil | 10.7% |
| Canada Oil Sands | |
| Mexico Crude Oil | 10.2% |
| Saudi Arabia Crude Oil | 9.4% |
| Venezuela Crude Oil | 8.1% |
| Nigeria Crude Oil | 7.1% |
| Iraq Crude Oil | 3.4% |
| Angola Crude Oil | 3.0% |
| Ecuador Crude Oil | 1.8% |
| Algeria Crude Oil | 1.5% |
| Kuwait Crude Oil | 1.5% |
| Other | 9.5% |

Country-specific crude oil extraction profiles were obtained by NETL from PE International for all major oil exporters to the U.S. aside from Canada and are available in the docket, EPA-HQ-OAR-2005-0161. Canadian crude oil extraction emissions are more difficult to estimate, as the U.S. imports both conventional oil and oil sands from Canada. To estimate emissions from Canadian conventional crude extraction, the U.S. conventional crude extraction profile was utilized, while incorporating Canada-specific data on venting and flaring rates.[TTTTTTT] For Canadian oil sands, extraction emission rates were derived using emissions reported by two major oil sands producers. These estimated values for oil sands production were comparable to those found by Charpentier et al. (2009)[651]. 9.5% of oil imports were grouped into a category termed "other", which consisted of imports from 31 countries. Due to the complexity and uncertainty associated with developing estimates for each of these countries, extraction emissions for this group were assumed to be the average of the conventional crude extraction emissions from the other importers for which specific extraction estimates were developed.

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[TTTTTTT] The U.S. extraction profile was used as a surrogate for extraction of Canadian conventional crude oil, as most data sources do not separate out emissions for Canadian conventional crude production from oil sands.

Extraction emissions for unfinished oils[UUUUUUU] were assumed to be the same as for crude oil extraction, with the addition of emissions for an atmospheric/vacuum distillation step after extraction. Unfinished oils were assumed to be of the same import mix as crude oil. Emissions associated with NGLs extraction were estimated using Canadian data for upstream oil and gas operations**.**

### 2.5.2.2 Foreign Refineries

Countries exporting gasoline and diesel to the U.S. were determined from EIA data. Table 2.5-3 reflects the percentage that imports made up of total U.S. consumption of gasoline and diesel.

**Table 2.5-3. Imports as a Percentage of 2005 U.S. Consumption**

| Product | Percentage of U.S. Consumption |
|---|---|
| Conventional Gasoline | 12.7% |
| Conventional Diesel | 5.2% |

Canada and the Virgin Islands were the primary liquid fuel exporters to the U.S., so extraction emissions associated with fuels imported from those countries were estimated more rigorously. Canada consisted of 25% of the finished motor gasoline imported to the U.S. and 32% of the diesel imported, while the Virgin Islands accounted for 17% of the gasoline and 29% of the diesel. For both of these countries, the crude oil import mix was known, so crude oil extraction emissions were estimated using the PE International extraction profiles.

The estimation method for other liquid fuel exporters to the U.S. depended on the origin of the crude oil utilized. In some cases, crude oil was extracted in the same country in which it was refined, so extraction emissions could be estimated from PE International extraction profiles. In other cases, crude oil was imported from one country for refining in another, and the crude import mix was not entirely clear. For most of these countries, PE International's GaBi 4 Life Cycle Assessment Software[VVVVVVV] was utilized to provide estimates of extraction emissions.

This still left a handful of countries for which there was no method to estimate extraction emissions. For these cases, "surrogate" profiles were used. For instance, for European countries for which a country-specific profile was not available, the EU-15 or EU-25 extraction profile was utilized. For South Korea, it is known that the source of crude oil is primarily Saudi Arabia, so the Saudi profile was utilized to estimate extraction emissions. For the remainder of countries, the extraction emissions were estimated to be the foreign average of all crude profiles. In total, the foreign average profile was used for 9% of the gasoline crude oil mix and 12% of the diesel crude oil mix.

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[UUUUUUU] "All oils requiring further processing, except those requiring only mechanical blending. Unfinished oils are produced by partial refining of crude oil and include naphthas and lighter oils, kerosene and light gas oils, heavy gas oils, and residuum." Department of Energy: U.S. Energy Information Administration. "Glossary" http://www.eia.doe.gov/glossary/glossary_u.htm.

[VVVVVVV] "[PE International's] GaBi software allows all the GHG emissions of your product to be captured in a systematic and transparent way. Primary data specific to your product can then be incorporated into your analyses and combined with secondary data on GHG emissions available from the GaBi databases." PE International. Product Carbon Footprint. < http://www.pe-international.com/consulting/carbon-footprint/product-carbon-footprint>

### 2.5.3 Crude Oil Transport

For domestic refineries, the NETL report states that "[c]rude oil transport to U.S. refineries includes pipeline transport within the exporting country, ocean tanker transport to the U.S., and domestic crude oil transport to refineries via a combination of pipeline, water carrier, rail, and truck." All crude is assumed to be transported by pipeline 100 miles to the U.S. border or to a port for shipping to the U.S., with the energy intensity for pipeline transport assumed to be 260 Btu/ton-mile. Based on EIA data, the distance from the foreign port to the U.S receiving port was estimated for the top ten countries from which crude oil was imported. For all other countries, the one-way travel distance was assumed to be 10,000 nautical miles.

**Table 2.5-4. Travel distance for crude oil based on country of origin**

| Crude Oil Sources | Import as % of Refinery Crude Input (Year 2005, EIA) | Country-Specific Average One-Way Travel Distance (nautical miles) |
|---|---|---|
| Canada Waterborne | 3.0% | 675 |
| Canada Pipeline | 7.7% | NA |
| Mexico Crude Oil | 10.2% | 1,061 |
| Saudi Arabia Crude Oil | 9.4% | 12,018 |
| Venezuela Crude Oil | 8.1% | 1,789 |
| Nigeria Crude Oil | 7.1% | 5,672 |
| Iraq Crude Oil | 3.4% | 12,370 |
| Angola Crude Oil | 3.0% | 6,736 |
| Ecuador Crude Oil | 1.8% | 5,653 |
| Algeria Crude Oil | 1.5% | 4,452 |
| Kuwait Crude Oil | 1.5% | 12,526 |
| Other | 9.5% | 10,000 |

Emissions arising from domestic transport of crude were estimated using the breakout of crude oil transportation modes for 2004, as illustrated in Table 2.5-5.

**Table 2.5-5. Domestic transportation breakout for crude oil**

| Pipelines | Water Carriers | Motor Carriers | Railroads |
|---|---|---|---|
| 75.9% | 23.7% | 0.3% | 0.1% |

For foreign refineries where extraction and refining occurred in the same country, transport of 100 miles by pipeline from well to refinery was assumed. For countries which imported crude, refined it into liquid fuels, and exported the liquid fuels to the U.S., the GaBi 4 Life Cycle Assessment Software gave estimates of the emissions associated with crude oil transport. For Canada, the Virgin Islands, and South Korea, crude oil transport distances by tanker were estimated, with the only exception that crude exported from the U.S. to Canada traveled by pipeline. Transport of crude oil from the port of entry into the United States to the petroleum refinery is not included in the model, since an analysis of petroleum refinery locations indicated that most refineries are geographically located near the port of entry. The exclusion of this transport operation was determined to have a negligible effect on the final results.

Transport of unfinished oils was modeled in the same way as crude oil transport. Transport of NGLs was modeled in similar way to transport and distribution of petroleum products, which is described in Section 2.5.4, “Fuel Transport and Distribution”.

### 2.5.4 Refining

NETL’s refining emissions estimation accounts for the following:

- Acquisition of fuels
    - Indirect emissions associated with purchased power and steam
    - Emissions associated with the acquisition of coal and natural gas purchased and consumed at the refinery as fuels
    - Emissions associated with production of fuels at the refinery which are subsequently consumed as fuels (i.e. still gas, petroleum coke)
- Combustion of fuels at the refinery
- Hydrogen production (on-site and off-site)
    - Upstream emissions associated with natural gas feed
    - $CO_2$ process emissions from steam methane reforming (SMR)
    - Fuel combustion and upstream emissions associated with natural gas fuel and indirect (electricity) emissions for *off-site* hydrogen production
- Flaring
- Venting and fugitive emissions

The NETL report indicates that, “The emissions above will be organized into a refinery emissions pool and a hydrogen emissions pool and subsequently allocated between the various refinery products. There are no individual assignments of energy sources to unit operations or refinery products.”

To determine the GHG emissions from the refining of gasoline and diesel, NETL first determined the total refining emissions from fuels combustion, fuels acquisition, flaring, hydrogen production, and methane venting. For each of the refinery units, they then used the capacity/throughput, energy, hydrogen consumption, and contribution to the final product slate to allocate emissions to gasoline and diesel production.

A domestic refinery model was used as a surrogate for all foreign refinery operations. A review of foreign refinery models from PE Americas indicated that differences in boundary conditions and allocation procedures introduced greater uncertainty in the final results than using the domestic refinery model as a surrogate for foreign refinery operations. The use of the domestic refinery model for foreign refinery operations was noted by NETL as a data limitation to the study.

### 2.5.5 Fuel Transport and Distribution

"Product transport includes transport of imported liquid fuels from the exporting nations to the U.S. as well as domestic transport of both imported fuels and domestically produced liquid fuels." Foreign transport consists of tanker and/or pipeline transport of imported products to U.S. ports. The products are assumed to be shipped 10 miles by pipeline to a port or the U.S. border. Specific port-to-port travel distances were calculated for imports from Canada and the U.S. Virgin Islands. All other product imports were assumed to travel 5,000 nautical miles to the U.S. Emissions arising from domestic transport were estimated using the breakout of petroleum product transportation modes for 2004, as shown in Table 2.5-6.

**Table 2.5-6. Domestic transportation breakout for petroleum products**

| Pipelines | Water Carriers | Motor Carriers | Railroads |
|---|---|---|---|
| 59.8% | 29.9% | 6.3% | 4.0% |

### 2.5.6 Tailpipe Emissions

We updated the $CO_2$ emission factors for gasoline and diesel to reflect revisions in the factors made by EPA, which were used in the September 28, 2009 proposed rule to establish GHG standards for light-duty vehicles. We have also updated the $CO_2$ emissions factors for ethanol and biodiesel to be consistent with those used in the October 30, 2009 final rulemaking for the Mandatory GHG Reporting Rule. For the final rule, we have maintained the same $CH_4$ and $N_2O$ emission factors used for the proposed rule, which were based on EPA MOVES model run results.

**Table 2.5-7. Tailpipe emissions for relevant fuels (g/mmBTU)**

| Fuel Type | $CO_2$ | $CH_4$ | $N_2O$ |
|---|---|---|---|
| Gasoline | 77,278 | 3 | 5 |
| Diesel | 78,308 | 1 | 2 |
| Ethanol | 75,885 | 13 | 2 |
| Biodiesel | 79,837 | 1 | 2 |

### 2.5.7 Land Use Change GHG Emissions

For the final rule, we performed an estimate of land use change emissions associated with oil extraction and production to determine if the value was significant enough to be included in our petroleum baseline calculation. As oil sands production incurs a greater degree of land use change versus conventional crude oil production, we started with an estimate of emissions from the conversion of Alberta forest for oil sands production.

Jordaan et al. (2009) estimated the land use change intensity for oil sands surface mining and in-situ development, using data on project area and established reserves. They estimated an average of 0.42 $m^2/m^3$ synthetic crude oil (SCO) for surface mining and 0.11 $m^2/m^3$ SCO for in-situ. These intensity values were based on dividing the area of land disturbance by the total volume of SCO produced over the lifetime of the project. Jordaan also calculated values for land use change associated with upgrading of oil sands and for the extraction of natural gas utilized for oil sands production. However, we restricted our calculation to consider only the land-use change associated with oil sands production to be consistent with the life cycle analysis methodology that we established for renewable fuels.[wwwwwww]

We then utilized the Winrock database values to determine GHG emissions from land use change of Alberta forest, the assumed area where oil sand extraction would occur. Per IPCC Guidelines, we assumed that 20% of the soil carbon was lost from conversion, which gave an overall value of 278.25 grams $CO_2$/hectare over a 30 year timeframe. We multiplied the land use change intensity and the GHG emissions from land-use change to yield a GHG intensity value. This calculation yielded values of 1,858 (1,460-2,787) grams $CO_2$/bbl for surface mining and 487 (310-708) grams/bbl for in-situ. These values were considerably lower (approximately 98%) than the oil sands extraction estimates determined by NETL and used in our petroleum baseline (81,000-122,000 g $CO_2$/bbl).

On a gasoline basis, the land-use change values were 380 (298-570) g $CO_2$/mmbtu for surface mining and 99 (63-145) g $CO_2$/mmbtu for in-situ. Since oil sands only comprised about 5% of the crude oil mix to domestic refineries in 2005, these estimates were adjusted to determine their impact on the aggregate well-to-tank petroleum baseline totals. For surface mining, the oil sands land use change value was on the order of 0.1% of total well-to-tank $CO_2$ emissions, and, for in-situ, it was 0.06%. Although these values likely represent the worst-case land use impact of petroleum extraction, they are still negligible in the total well-to-tank values and including them would not change the overall petroleum baseline values. We anticipate that future work will help to quantify these values, and we can evaluate the appropriateness of including a land use estimate in the future.

### 2.5.8 Petroleum Fuel 2005 Baseline Well-to-Tank GHG Emissions

The results for each of the lifecycle stages were combined to give a well-to-tank lifecycle GHG value for 2005 gasoline and diesel as shown in Table 2.5-8. Tailpipe combustion emissions for the two fuels are described in Section 2.5.6. When combined with the tailpipe emissions values, a well-to-wheels result for gasoline of 98,205 grams $CO_2$eq/mmBTU and 97,006 grams $CO_2$eq/mmBTU was obtained.

**Table 2.5-8.**
**Gasoline and diesel baseline well-to-tank GHG emissions (g/mmbtu of fuel)**

| | $CO_2$ | $CH_4$ | $N_2O$ | $CO_2$eq. |
|---|---|---|---|---|
| Gasoline | 16,816 | 2,282 | 103 | 19,200 |
| Diesel | 15,838 | 2,066 | 94 | 17,998 |

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[wwwwwww] In other words, when considering the GHG impacts of renewable fuels, we did not consider GHG emissions from land use change associated with infrastructure or natural gas extracted and used for renewable fuels production.

## 2.6 Fuel-Specific Lifecycle Greenhouse Gas Emissions Results

In this section we present detailed lifecycle GHG analysis results, including the results of sensitivity and scenario analyses on key assumptions. As discussed above, to implement the EISA the crucial result that determines which renewable fuel pathways qualify for RFS2 credits is the percent reduction in lifecycle GHG emissions compared to the average lifecycle greenhouse gas emissions for gasoline or diesel sold or distributed as transportation fuel in 2005. To compare lifecycle GHG emissions from renewable fuels and petroleum, we present the grams of $CO_2$-equivalent emissions per BTU of fuel produced ($gCO_2eq/mmBTU$). The previous sections in this chapter discussed our methodology for calculating lifecycle GHG emissions for each component of the renewable fuel lifecycle, and for the 2005 petroleum baseline. In this section we present and compare the GHG emissions results for each of these components in the fuel lifecycle. We also discuss how key assumptions can change the GHG emissions from each component of the fuel lifecycle, and how they influence the final GHG percent reduction estimates.

In addition to estimating GHG emissions at every stage of the fuel lifecycle, EPA's task in this rulemaking is to integrate the GHG emissions estimates from all stages of the lifecycle in order to estimate lifecycle GHG percent reductions for each renewable fuel pathway. We have considered a number of ways to meet this challenge, and have identified several key methodological issues that can influence whether a particular renewable fuel pathway meets the thresholds set forth in the EISA.

### 2.6.1 Renewable Fuel Lifecycle GHG Results

This section presents fuel specific lifecycle GHG results for the different renewable fuels compared to the petroleum baseline fuel replaced. Results are presented for the baseline set of assumptions including:

- Business as usual yields
- 30 year 0% discounted
- 2022 year for results

Sensitivity around these assumptions are presented in Section 2.6.2. This section presents the results as a range based on the uncertainty analysis conducted around the land use change emissions.

### 2.6.1.1 Corn Ethanol Results

EPA analyzed the lifecycle GHG performance of a variety of ethanol from corn starch pathways. The results presented here are for an average natural gas fired dry mill plant in 2022. We predict approximately 90% of all plants will be producing corn oil as a by-product either through a fractionation or extraction process; it is likely most if not all new plants will elect to include such technology. We also expect that, to lower their operating costs, most facilities will sell a portion of their co-product DGS prior to drying thus reducing energy consumption and improving the efficiency and lifecycle GHG performance of the plant. The current national average plant sells approximately 37% of the DGS co-product prior to drying.

Figure 2.6-1 shows the percent change in the lifecycle GHG emissions compared to the petroleum gasoline baseline in 2022 for a corn ethanol dry mill plant using natural gas for its process energy source, drying the national average of 63% of the DGS it produces and employing corn oil fractionation technology. Lifecycle GHG emissions equivalent to the gasoline baseline are represented on the graph by the zero on the X-axis. The 20% reduction threshold is represented by the dashed line at -20% on the graph. The results for this corn ethanol scenario are that the midpoint of the range of results is a 21% reduction in GHG emissions compared to the gasoline 2005 baseline. The 95% confidence interval around that midpoint ranges from a 7% reduction to a 32% reduction compared to the gasoline baseline based on the uncertainty in the land use change assumptions.

**Figure 2.6-1. Distribution of Results for a New Natural Gas Fired Corn Ethanol Plant Average 2022 plant: natural gas, 63% dry, 37% wet DGS (w/ fractionation)**

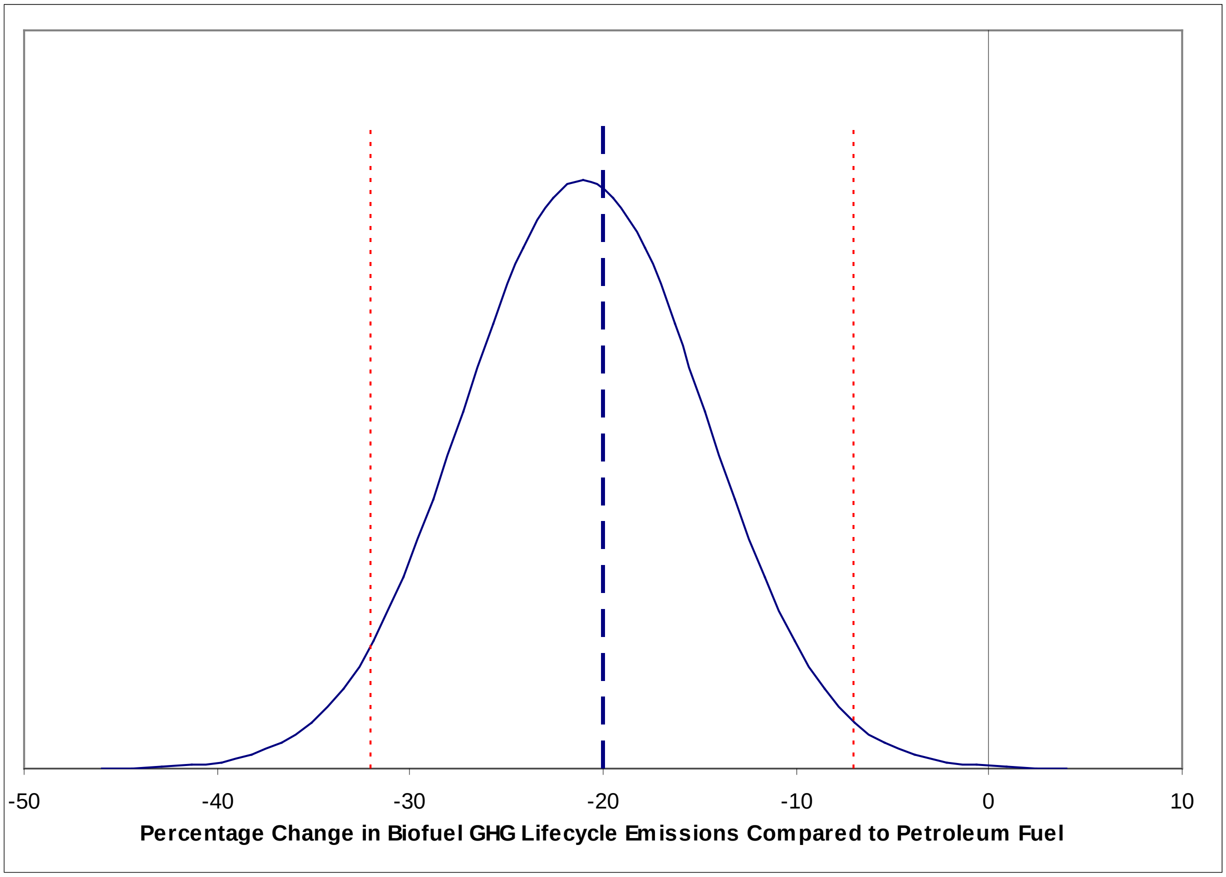
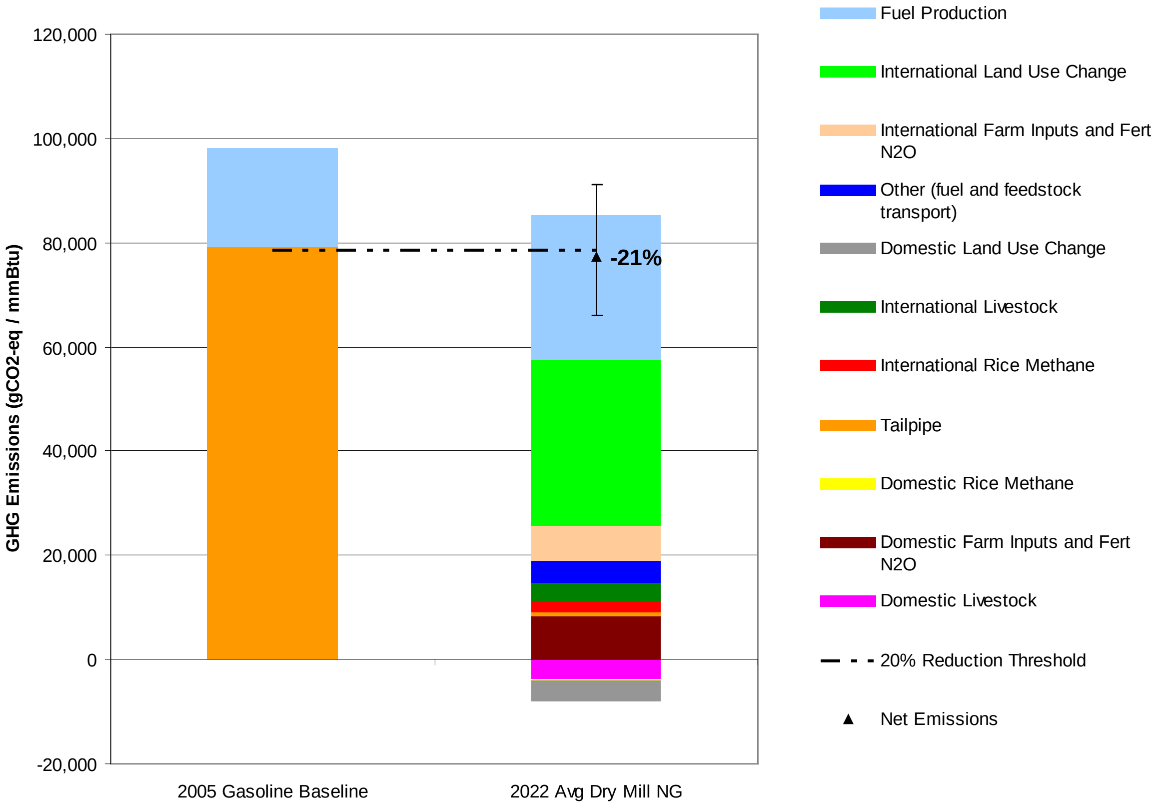


Figure 2.6-2 includes lifecycle GHG emissions broken down by several stages of the lifecycle impacts for the typical corn ethanol depicted in Figure 2.6-1 compared to the 2005 baseline average for gasoline. Lifecycle emissions are normalized per energy unit of fuel produced and presented in grams of carbon-dioxide equivalent GHG emissions per million British Thermal Units of fuel produced (gCO$_2$e/mmBTU). Figure 2.6-2 includes our mean

estimate of international land use change emissions as well as the 95% confidence range from our uncertainty assessment, which accounts for uncertainty in the types of land use changes and the magnitude of resulting GHG emissions.  For the petroleum baseline, the fuel production stage includes emissions from extraction, transport, refining and distribution of petroleum transportation fuel.  Petroleum tailpipe emissions include $CO_2$ and non-$CO_2$ gases emitted from fuel combustion.

**Figure 2.6-2.  Results for a New Natural Gas Fired Corn Ethanol Plant by Lifecycle Stage Average 2022 plant: natural gas, 63% dry, 37% wet DGS (w/ fractionation)**



We also looked at a number of different plat types, technologies and fuel types used. Figure 2.6-3 shows the results for an average 2022 corn ethanol dry mill plant (fractionation and 63% dry DGS) but with different fuel sources, natural gas coal and biomass.

**Figure 2.6-3. Results for New Corn Ethanol Plants by Fuel Source and Lifecycle Stage Average 2022 plant: 63% dry, 37% wet DGS (w/ fractionation)**

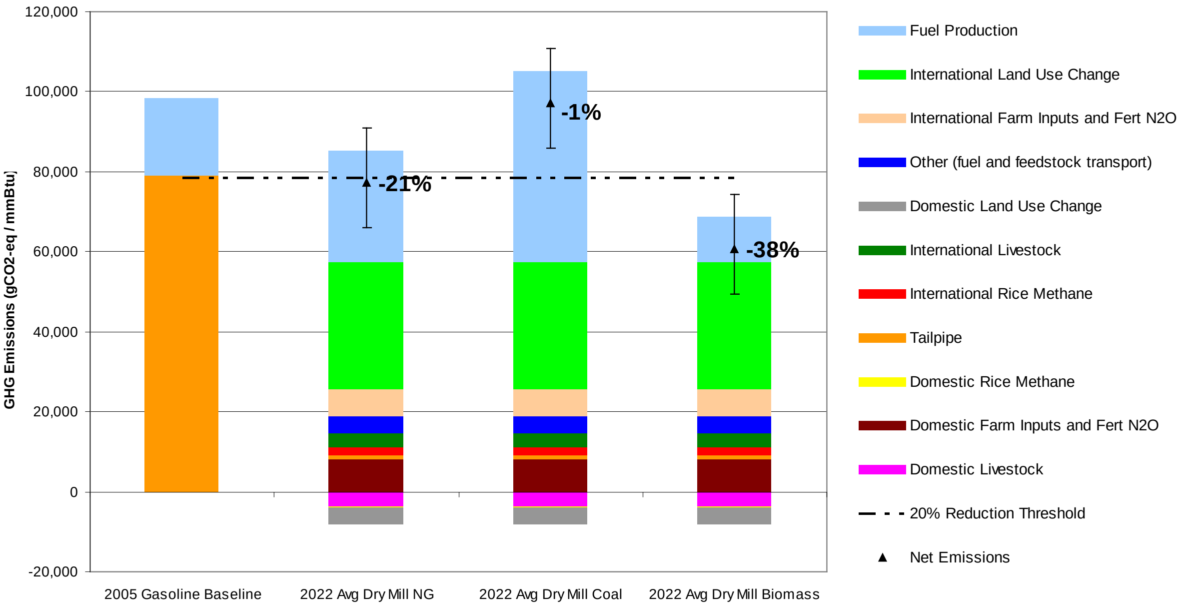


Table 2.6-1 shows the results for all of the different corn ethanol pathways considered.

**Table 2.6-1. Results for New Corn Ethanol Plants by Type**

| Plant Type | Plant Technology | Percent Change in Lifecycle GHG Emissions | | |
|---|---|---|---|---|
| | Time Horizon (years)<br>Discount Rate<br>Range | 30<br>0%<br>Low | 30<br>0%<br>Mean | 30<br>0%<br>High |
| Dry Mill NG | Base Plant (dry DGS) | -28% | -17% | -3% |
| Dry Mill NG | w/ CHP (dry DGS) | -31% | -20% | -6% |
| Dry Mill NG | w/ Fractionation (dry DGS) | -30% | -18% | -4% |
| Dry Mill NG | w/ CHP and Fractionation (dry DGS) | -33% | -22% | -7% |
| Dry Mill NG | w/ Fractionation and Membrane Separation (dry DGS) | -33% | -22% | -8% |
| Dry Mill NG | w/ CHP, Fractionation and Membrane Separation (dry DGS) | -37% | -25% | -11% |
| Dry Mill NG | w/ Fractionation, Membrane Separation, and Raw Starch Hydrolysis (dry DGS) | -38% | -26% | -12% |
| Dry Mill NG | w/ CHP, Fractionation, Membrane Separation, and Raw Starch Hydrolysis (dry DGS) | -41% | -30% | -15% |
| Dry Mill NG | Base Plant (wet DGS) | -39% | -27% | -13% |
| Dry Mill NG | w/ CHP (wet DGS) | -42% | -30% | -16% |
| Dry Mill NG | w/ Fractionation (wet DGS) | -38% | -26% | -12% |
| Dry Mill NG | w/ CHP and Fractionation (wet DGS) | -41% | -29% | -15% |
| Dry Mill NG | w/ Fractionation and Membrane Separation (wet DGS) | -41% | -30% | -16% |
| Dry Mill NG | w/ CHP, Fractionation and Membrane Separation (wet DGS) | -44% | -33% | -19% |
| Dry Mill NG | w/ Fractionation, Membrane Separation, and Raw Starch Hydrolysis (wet DGS) | -44% | -33% | -18% |
| Dry Mill NG | w/ CHP, Fractionation, Membrane Separation, and Raw Starch Hydrolysis (wet DGS) | -47% | -36% | -22% |
| Dry Mill Coal | Base Plant (dry DGS) | 1% | 12% | 26% |
| Dry Mill Coal | w/ CHP (dry DGS) | -1% | 10% | 24% |
| Dry Mill Coal | w/ Fractionation (dry DGS) | -7% | 5% | 19% |
| Dry Mill Coal | w/ CHP and Fractionation (dry DGS) | -9% | 3% | 17% |
| Dry Mill Coal | w/ Fractionation and Membrane Separation (dry DGS) | -14% | -3% | 11% |
| Dry Mill Coal | w/ CHP, Fractionation and Membrane Separation (dry DGS) | -16% | -5% | 9% |
| Dry Mill Coal | w/ Fractionation, Membrane Separation, and Raw Starch Hydrolysis (dry | -23% | -12% | 2% |

| Plant Type | Plant Technology | Percent Change in Lifecycle GHG Emissions | | |
|---|---|---|---|---|
| | DGS) | | | |
| Dry Mill Coal | w/ CHP, Fractionation, Membrane Separation, and Raw Starch Hydrolysis (dry DGS) | -25% | -14% | 0% |
| Dry Mill Coal | Base Plant (wet DGS) | -21% | -10% | 4% |
| Dry Mill Coal | w/ CHP (wet DGS) | -23% | -12% | 2% |
| Dry Mill Coal | w/ Fractionation (wet DGS) | -23% | -11% | 3% |
| Dry Mill Coal | w/ CHP and Fractionation (wet DGS) | -25% | -13% | 1% |
| Dry Mill Coal | w/ Fractionation and Membrane Separation (wet DGS) | -30% | -19% | -5% |
| Dry Mill Coal | w/ CHP, Fractionation and Membrane Separation (wet DGS) | -32% | -21% | -7% |
| Dry Mill Coal | w/ Fractionation, Membrane Separation, and Raw Starch Hydrolysis (wet DGS) | -36% | -24% | -10% |
| Dry Mill Coal | w/ CHP, Fractionation, Membrane Separation, and Raw Starch Hydrolysis (wet DGS) | -38% | -26% | -12% |
| Dry Mill Biomass | Base Plant (dry DGS) | -51% | -40% | -26% |
| Dry Mill Biomass | w/ CHP (dry DGS) | -59% | -47% | -33% |
| Dry Mill Biomass | w/ Fractionation (dry DGS) | -49% | -38% | -24% |
| Dry Mill Biomass | w/ CHP and Fractionation (dry DGS) | -57% | -45% | -31% |
| Dry Mill Biomass | w/ Fractionation and Membrane Separation (dry DGS) | -49% | -38% | -24% |
| Dry Mill Biomass | w/ CHP, Fractionation and Membrane Separation (dry DGS) | -56% | -45% | -31% |
| Dry Mill Biomass | w/ Fractionation, Membrane Separation, and Raw Starch Hydrolysis (dry DGS) | -49% | -38% | -24% |
| Dry Mill Biomass | w/ CHP, Fractionation, Membrane Separation, and Raw Starch Hydrolysis (dry DGS) | -57% | -45% | -31% |
| Dry Mill Biomass | Base Plant (wet DGS) | -52% | -41% | -27% |
| Dry Mill Biomass | w/ CHP (wet DGS) | -59% | -48% | -34% |
| Dry Mill Biomass | w/ Fractionation (wet DGS) | -50% | -39% | -25% |
| Dry Mill Biomass | w/ CHP and Fractionation (wet DGS) | -57% | -46% | -32% |
| Dry Mill Biomass | w/ Fractionation and Membrane Separation (wet DGS) | -50% | -38% | -24% |
| Dry Mill Biomass | w/ CHP, Fractionation and Membrane Separation (wet DGS) | -57% | -45% | -31% |
| Dry Mill Biomass | w/ Fractionation, Membrane Separation, and Raw Starch Hydrolysis (wet DGS) | -50% | -38% | -24% |
| Dry Mill Biomass | w/ CHP, Fractionation, Membrane Separation, and Raw Starch Hydrolysis (wet DGS) | -57% | -46% | -32% |
| Wet Mill | with NG | -19% | -7% | 7% |
| Wet Mill | with Coal | 8% | 19% | 33% |
| **Wet Mill** | with Biomass | -59% | -48% | -33% |

### 2.6.1.2 Corn Butanol Results

We analyzed corn butanol, similar to corn ethanol in terms of types of plants and technologies.

Figure 2.6-4 shows the percent change in the lifecycle GHG emissions compared to the petroleum gasoline baseline in 2022 for a corn butanol dry mill plant using natural gas for its process energy source, drying the national average of 63% of the DGS it produces and employing corn oil fractionation technology. Lifecycle GHG emissions equivalent to the gasoline baseline are represented on the graph by the zero on the X-axis. The 20% reduction threshold is represented by the dashed line at -20 on the graph. The results for this corn butanol scenario are that the midpoint of the range of results is a 31% reduction in GHG emissions compared to the gasoline 2005 baseline. The 95% confidence interval around that midpoint ranges from a 20% reduction to a 40% reduction compared to the gasoline baseline based on the uncertainty in the land use change assumptions.

The butanol results in slightly greater GHG reductions compared to corn ethanol because of the greater energy content of the fuel. There is actually slightly more energy used in processing but there is a greater energy production output. Therefore, on a per mmBTU basis there are less GHG emissions produced across all the lifecycle.

**Figure 2.6-4. Distribution of Results for a New Natural Gas Fired Corn Butanol Plant Average 2022 plant: natural gas, 63% dry, 37% wet DGS (w/ fractionation)**

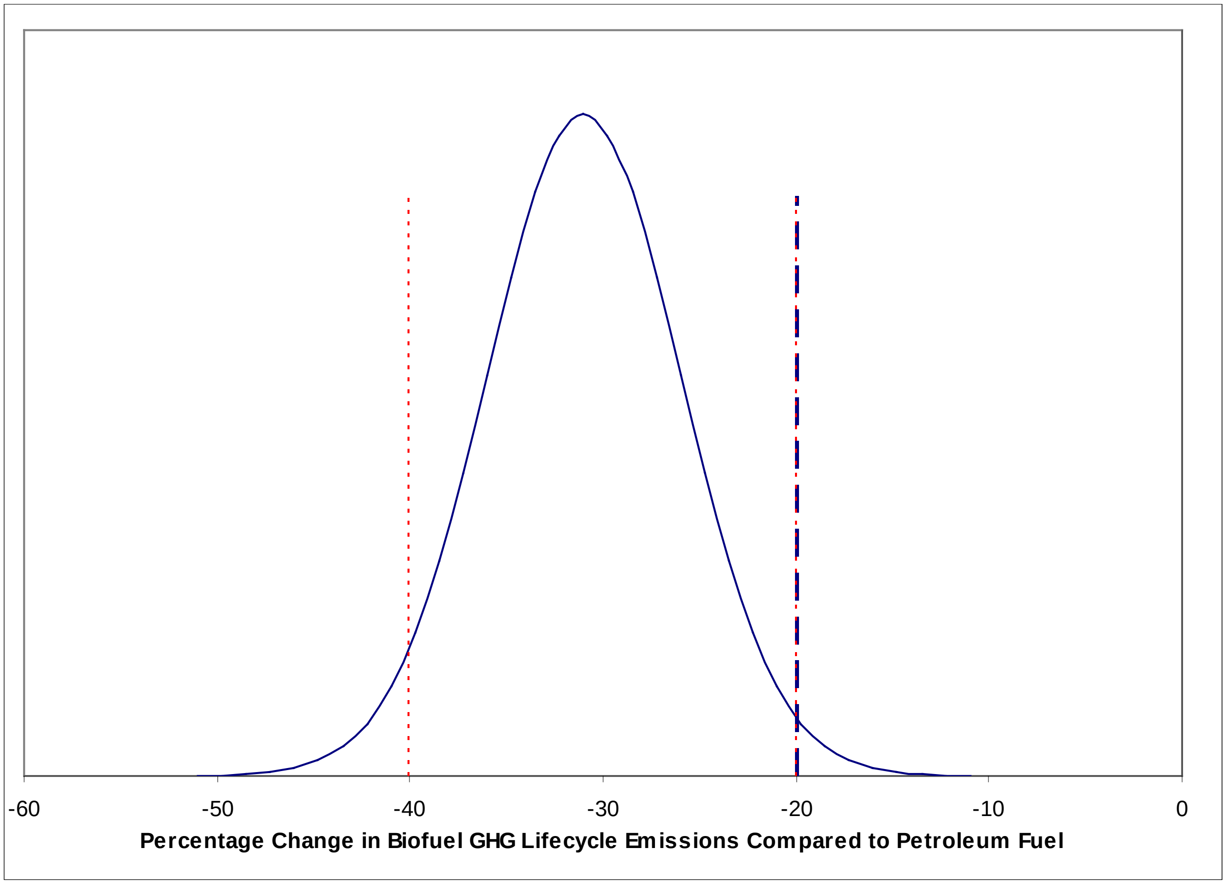
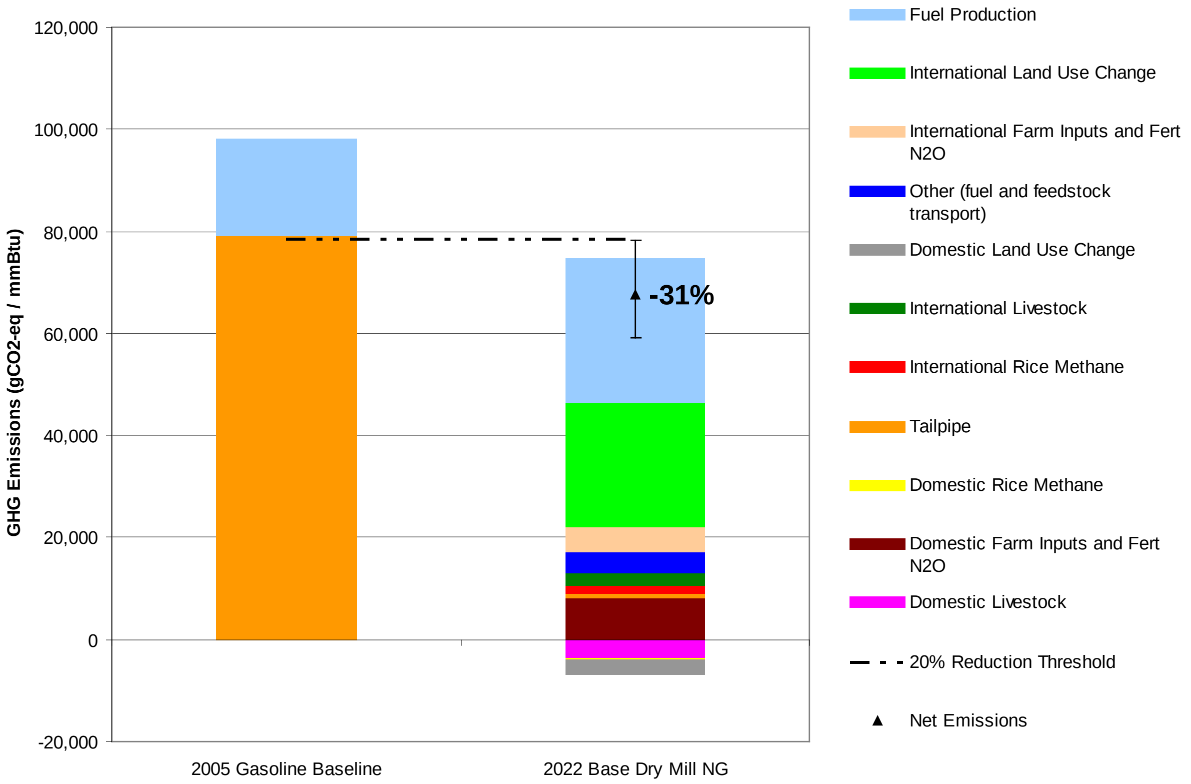


Figure 2.6-5 below includes lifecycle GHG emissions broken down by several stages of the lifecycle impacts for the typical corn butanol plant depicted in Figure 2.6-5 compared to the 2005 baseline average for gasoline. Lifecycle emissions are normalized per energy unit of fuel produced and presented in grams of carbon-dioxide equivalent GHG emissions per million British Thermal Units of fuel produced ($gCO_2e$/mmBTU).

Figure 2.6-5 includes our mean estimate of international land use change emissions as well as the 95% confidence range from our uncertainty assessment, which accounts for uncertainty in the types of land use changes and the magnitude of resulting GHG emissions.

**Figure 2.6-5. Results for New Corn Butanol Plants by Lifecycle Stage Average 2022 plant: 63% dry, 37% wet DGS (w/ fractionation)**



### 2.6.1.3 Biodiesel Results

Figure 2.6-6 shows the percent change in the typical 2022 soybean biodiesel lifecycle GHG emissions compared to the petroleum diesel fuel 2005 baseline. Lifecycle GHG emissions equivalent to the diesel fuel baseline are represented on the graph by the zero on the X-axis. The 50% reduction threshold is represented by the dashed line at -50 on the graph. The results for soybean biodiesel are that the midpoint of the range of results is a 57% reduction in GHG emissions compared to the diesel fuel baseline. The 95% confidence interval around that midpoint results in range of a 22% reduction to an 85% reduction compared to the diesel fuel 2005 baseline.

**Figure 2.6-6. Distribution of Results Soybean Biodiesel**
**Average 2022 plant; natural gas**

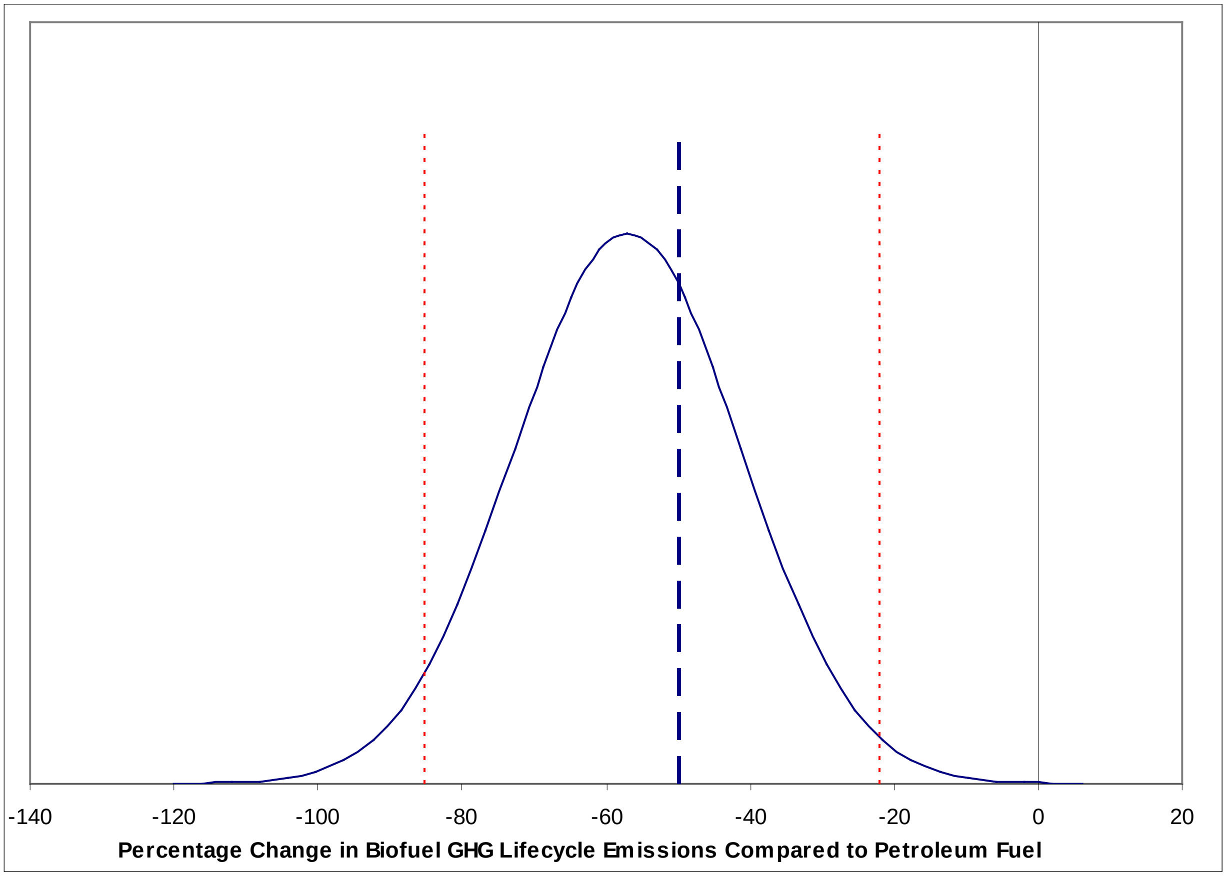


Figure 2.6-7 below includes lifecycle GHG emissions broken down by several stages of the lifecycle impacts for the typical soybean biodiesel plant depicted in Figure 2.6-6 compared to the 2005 baseline average for diesel fuel. Lifecycle emissions are normalized per energy unit of fuel produced and presented in grams of carbon-dioxide equivalent GHG emissions per million British Thermal Units of fuel produced (gCO2e/mmBTU). Figure 2.6-7 includes the mean estimate of international land use change emissions as well as the 95% confidence range from our uncertainty assessment, which accounts for uncertainty in the types of land use changes and the magnitude of resulting GHG emissions. Figure 2.6-7 also includes emissions from waste grease based biodiesel. The waste grease biodiesel does not have any agricultural or land use emissions and therefore only a point source estimate is shown for that pathway.

**Figure 2.6-7. Results for Biodiesel by Lifecycle Stage**
**Soybean and Waste Grease Feedstock**

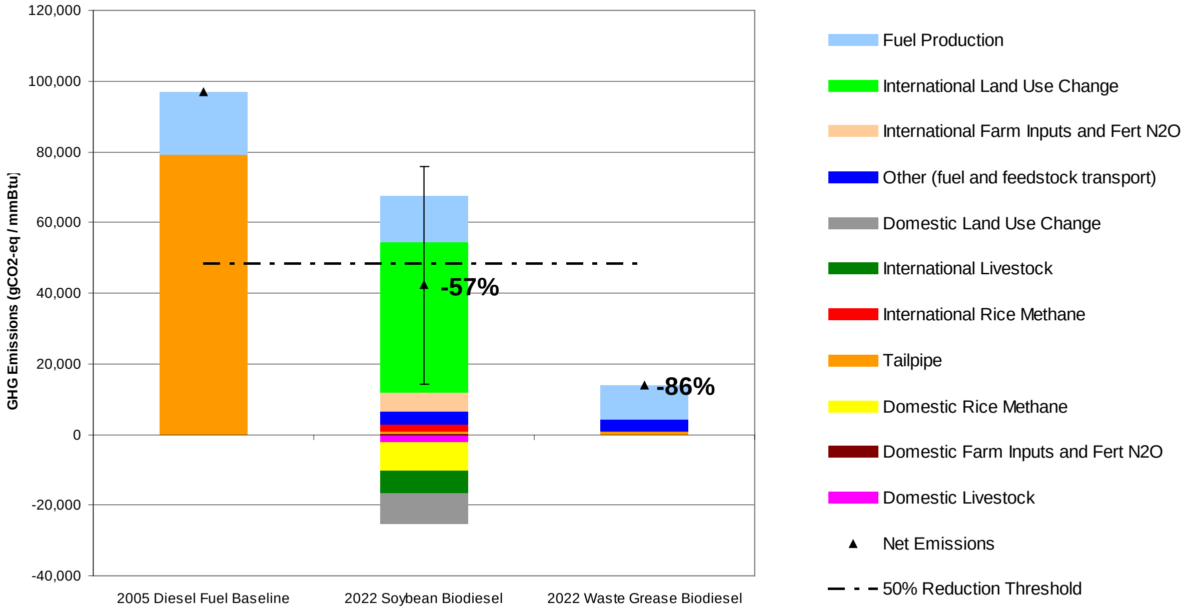
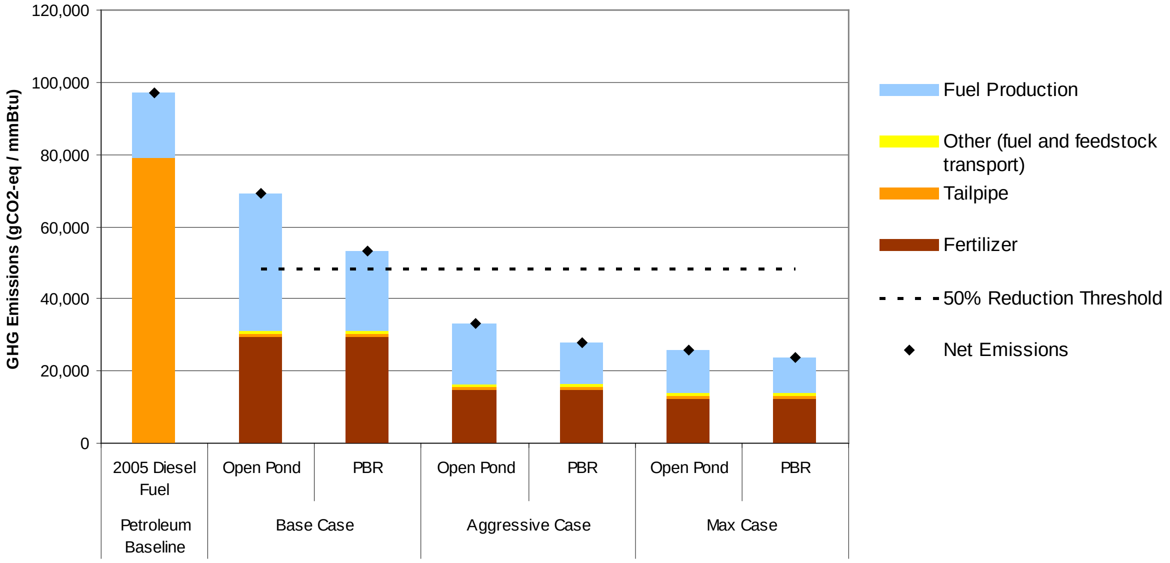


Figure 2.6-8 shows lifecycle GHG emissions broken down by several stages of the lifecycle impacts for algae oil to biodiesel compared to the 2005 baseline average for diesel fuel. Results are shown for the different cases of production described in Section 2.4.7.3.3. The algae oil biodiesel does not have any agricultural or land use emissions and therefore only a point source estimate is shown for each pathway.

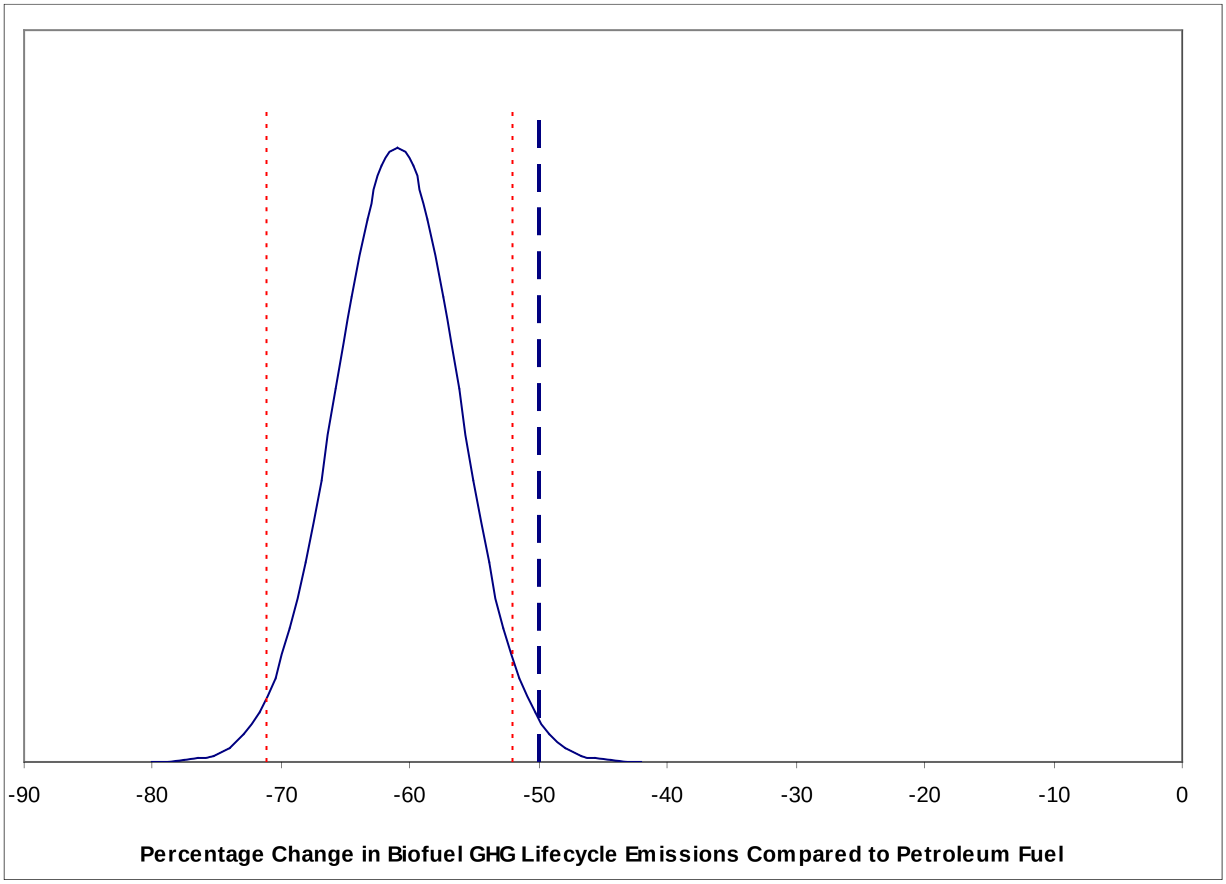
**Figure 2.6-8. Results for Algae Biodiesel by Lifecycle Stage**
**Algae Oil Feedstock**



### 2.6.1.4 Sugarcane Ethanol Results

Figure 2.6-9 shows the percent change in the average 2022 sugarcane ethanol lifecycle GHG emissions compared to the petroleum gasoline 2005 baseline. These results assume the ethanol is produced and dehydrated in Brazil prior to being imported into the U.S. and that the residue is not collected. Lifecycle GHG emissions equivalent to the gasoline baseline are represented on the graph by the zero on the X-axis. The 50% reduction threshold is represented by the dashed line at -50 on the graph. The results for this sugarcane ethanol scenario are that the midpoint of the range of results is a 61% reduction in GHG emissions compared to the gasoline baseline. The 95% confidence interval around that midpoint results in a range of a 52% reduction to a 71% reduction compared to the gasoline 2005 baseline.

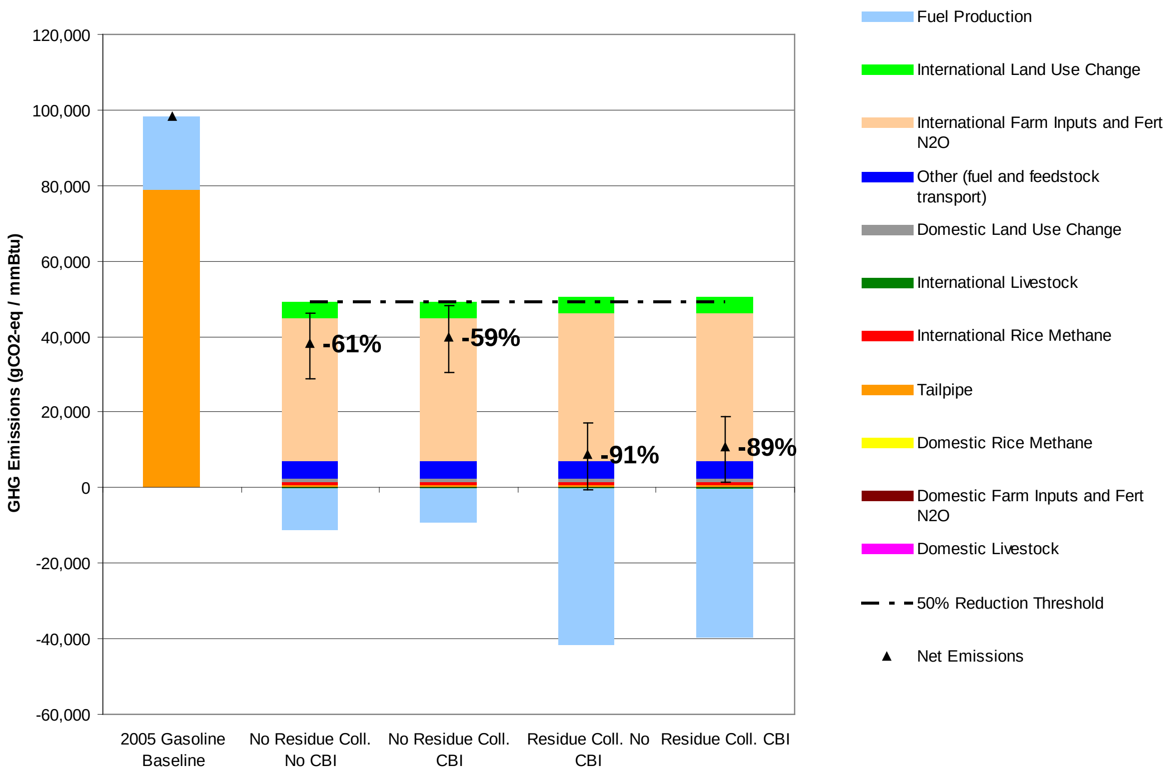
Figure 2.6-9. Distribution of Results for Sugarcane Ethanol
Average 2022 plant: no residue collection



We also considered pathways assuming most crop residue of the leaves as well as stalks are collected (and therefore available for burning as process energy) or without the extra crop residue being neither collected nor burned as fuel. We also analyzed pathways assuming the ethanol is distilled in Brazil or alternatively being distilled in the Caribbean ("CBI").

Figure 2.6-10 below includes lifecycle GHG emissions broken down by several stages of the lifecycle impacts for the difference sugarcane ethanol scenarios compared to the 2005 baseline average for gasoline. Lifecycle emissions are normalized per energy unit of fuel produced and presented in grams of carbon-dioxide equivalent GHG emissions per million British Thermal Units of fuel produced ($gCO_2e/mmBTU$). Figure 2.6-10 includes the mean estimate of international land use change emissions as well as the 95% confidence range from our uncertainty assessment, which accounts for uncertainty in the types of land use changes and the magnitude of resulting GHG emissions.

**Figure 2.6-10. Results for Sugarcane Ethanol by Lifecycle Stage
With and without residue collection and CBI**



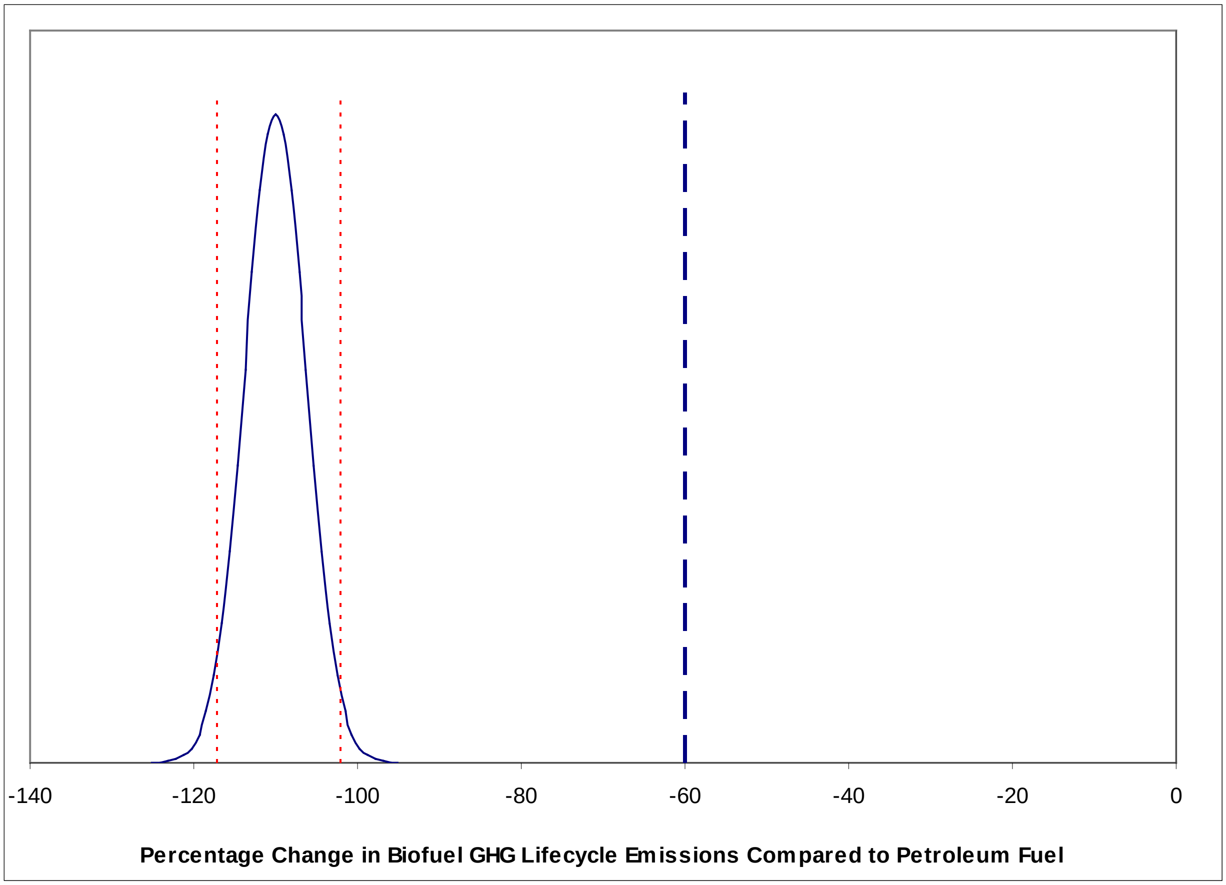
As Figure 2.6-10 indicates, the sugarcane ethanol scenarios with residue collection have greater GHG reductions compared to the no collection cases. For residue collection there is slightly more energy and emissions needed for crop production due to collection and transport of the residue. However, there are significantly more GHG savings at the plant due to more excess electricity production from burning the collected residues.

The CBI cases in which the ethanol is distilled in the Caribbean add slightly more GHG emissions from burning fossil fuels for dehydration. This is slightly offset by the additional excess electricity from the sugarcane ethanol plant that does not need to dehydrate the ethanol. Energy used for dehydration at the ethanol plant could then be used to generate excess electricity that offsets grid electricity production, and results in GHG savings.

### 2.6.1.5 Cellulosic Biofuels Results

Figure 2.6-11 shows the percent change in the average lifecycle GHG emissions in 2022 for ethanol produced from switchgrass using the biochemical process compared to the petroleum gasoline 2005 baseline. Lifecycle GHG emissions equivalent to the gasoline baseline are represented on the graph by the zero on the X-axis. The 60% reduction threshold is represented by the dashed line at -60 on the graph. The results for this switchgrass ethanol scenario are that the midpoint of the range of results is a 110% reduction in GHG emissions compared to the gasoline baseline. The 95% confidence interval around that midpoint ranges from 102% reduction to a 117% reduction compared to the gasoline baseline.

**Figure 2.6-11. Distribution of Results for Switchgrass Biochemical Ethanol**
**Average 2022 plant: biochemical process producing ethanol, excess electricity production**



We have also analyzed additional cellulosic biofuel pathways (i.e., thermochemical cellulosic ethanol and a BTL diesel pathway) as well as considered crop residues as a cellulosic feedstock. Figure 2.6-12 below includes lifecycle GHG emissions broken down by several stages of the lifecycle impacts for the different cellulosic feedstock to ethanol production scenarios compared to the 2005 baseline average for gasoline. Lifecycle emissions are normalized per energy unit of fuel produced and presented in grams of carbon-dioxide equivalent GHG emissions per million British Thermal Units of fuel produced ($gCO_2e/mmBTU$). Figure 2.6-12 includes the mean estimate of international land use change emissions as well as the 95% confidence range from our uncertainty assessment, which accounts for uncertainty in the types of land use changes and the magnitude of resulting GHG emissions. The residues to ethanol scenarios do not have any international land use emissions and therefore only a point source estimate is shown for those pathways.

**Figure 2.6-12. Results for Cellulosic Ethanol by Lifecycle Stage Biochemical and Thermochemical for Switchgrass and Corn Stover**

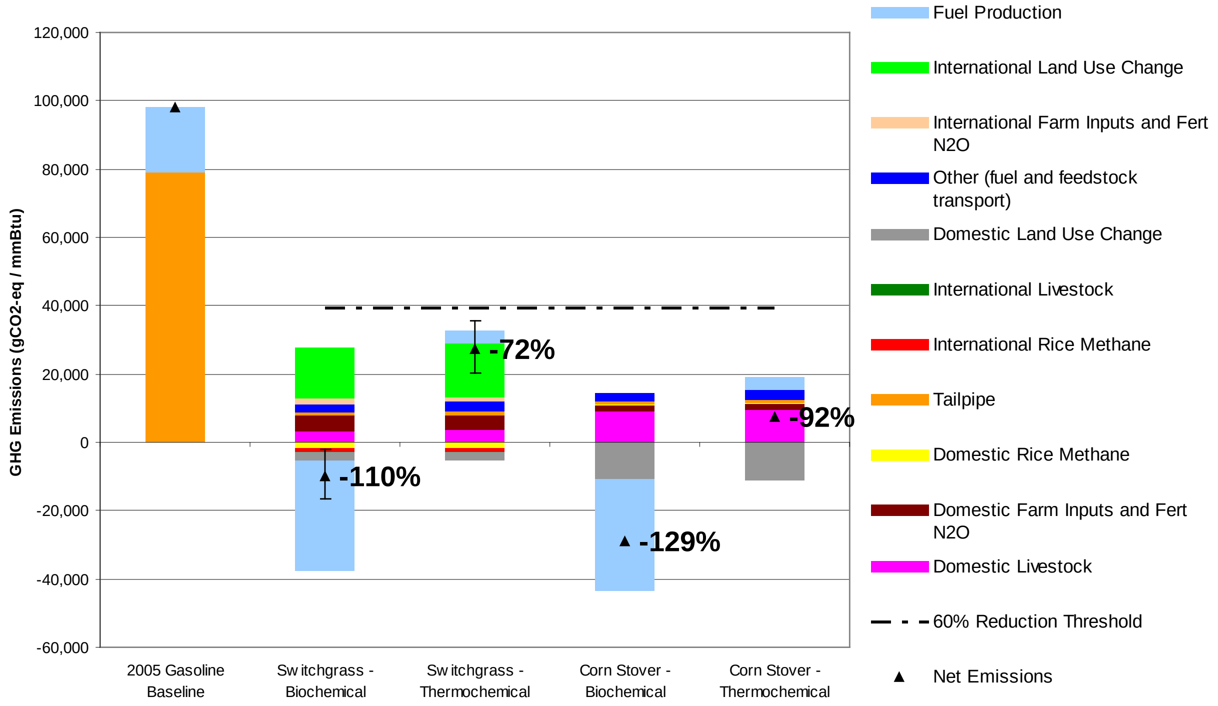
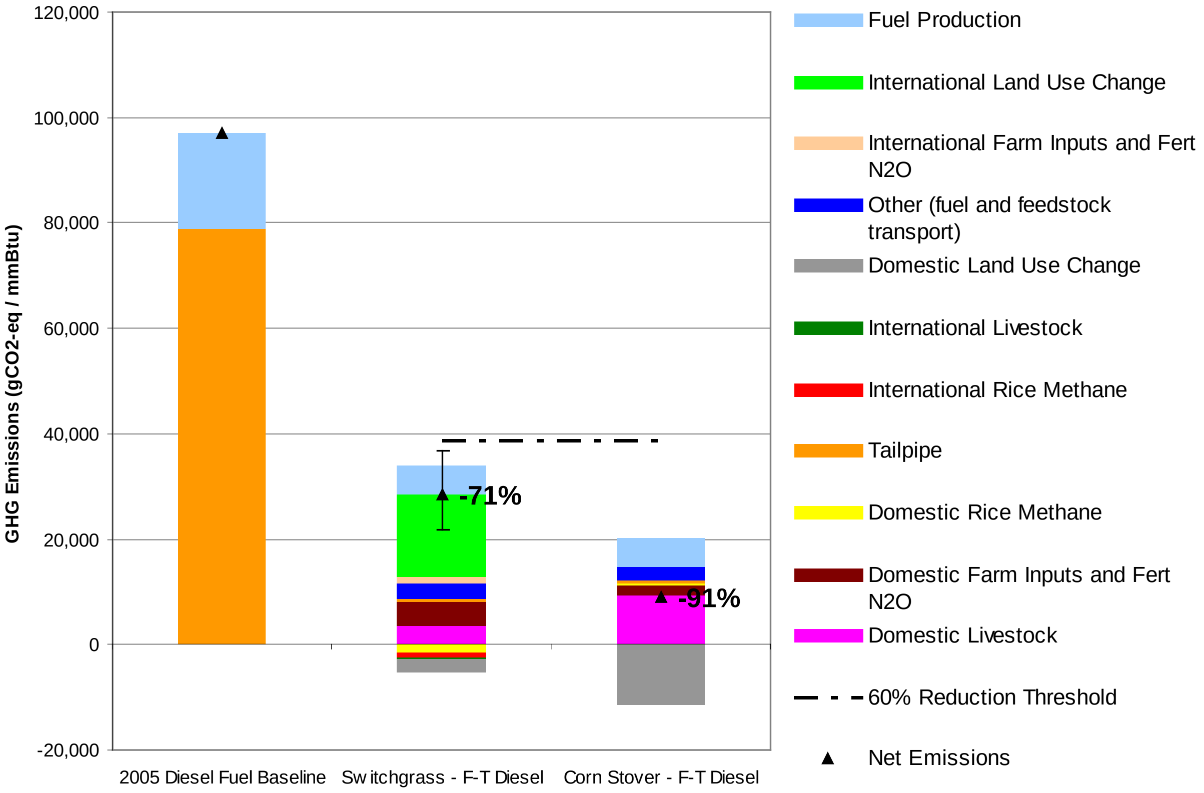


Figure 2.6-13 below includes lifecycle GHG emissions broken down by several stages of the lifecycle impacts for the different cellulosic feedstock to F-T diesel fuel production scenarios compared to the 2005 baseline average for diesel fuel. Lifecycle emissions are normalized per energy unit of fuel produced and presented in grams of carbon-dioxide equivalent GHG emissions per million British Thermal Units of fuel produced (gCO2e/mmBTU).

Figure 2.6-13. Results for Cellulosic Diesel Fuel by Lifecycle Stage
F-T Diesel Fuel for Switchgrass and Corn Stover



Biochemical ethanol production results in greater GHG savings compared to the thermochemical or F-T diesel fuel scenarios due to the excess electricity production from the lignin generated from the biochemical process. The corn stover scenarios have less overall agricultural sector GHG emissions compared to the switchgrass scenario and do not have international land use change emissions and therefore greater GHG savings.

## 2.6.2 Sensitivity Analysis

This section presents the results or several sensitivity analyses performed around the different main components of the lifecycle analysis. Some of the sensitivity analysis impact all fuels considered while some only impact specific fuels.

### 2.6.2.1 Timing and Discount Rate

In addition to estimating GHG emissions at every stage of the fuel lifecycle, EPA's task in this rulemaking is to integrate the GHG emissions estimates from all stages of the lifecycle in order to estimate lifecycle GHG percent reductions for each renewable fuel pathway. We have considered a number of ways to meet this challenge, and have identified several key methodological issues that can influence whether a particular renewable fuel pathway meets the thresholds set forth in the EISA. For example, one issue that deserves attention is the timing of lifecycle GHG emissions.

Section 2.4.5 explained that the lifecycle GHG emissions associated with biofuels can vary over time. Clearing forests, grasslands, and other types of land that sequester carbon, for crop production can results in GHG emissions for many years. As depicted in Figure 2.6-14, this type of land conversion produces large immediate GHG emissions, followed by a lesser stream of emissions that can last for many years. Biomass feedstocks grown annually on new cropland can be converted to biofuels that offer a GHG benefit relative to the petroleum product they replace, but these benefits may be small compared to the upfront GHG emissions associated with land clearing to expand crop production. Depending on the specific biofuel in question, it can take many years for the benefits of the biofuel to make up for the large initial releases of carbon that result from land conversion (e.g., the payback period).

The payback period calculation, presented graphically in Figure 2.6-14, represents the time it takes for the emissions savings from the production of biofuels to equal the potentially large initial emissions from land use changes. Although we do not believe it is appropriate to use the payback period for RFS2 compliance purposes, this calculation helps to illustrate the importance of the time dimension of renewable fuel lifecycle GHG emissions.

**Figure 2.6-14. Corn Ethanol Payback Period**

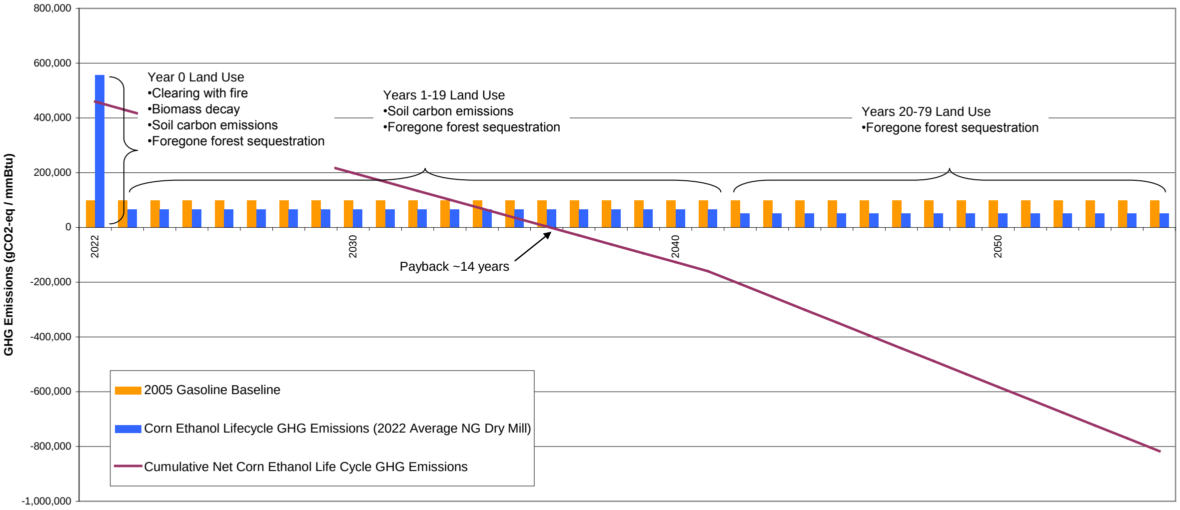


Figure 2.6-14 shows the baseline lifecycle GHG emissions from the 2022 average corn ethanol natural gas fired dry mill with fractionation and drying 63% of DGS, and from the 2005 gasoline baseline. In the first year, in this case 2022, corn ethanol lifecycle GHG emissions are more than five times greater than the gasoline it replaces. However, corn ethanol has ongoing GHG benefits in every subsequent year. It takes approximately 14 years for the annual GHG benefits of corn ethanol compared to gasoline to pay back the initial GHG releases from land clearing. This tells us that unless we analyze the lifecycle GHG emissions of corn ethanol over more than 14 years, corn ethanol from this pathway will not achieve a reduction compared to gasoline. As we extend our analysis beyond 14 years we will see increasing GHG reductions associated with the use of corn ethanol.

The same is true for other renewable fuels that result in land use change, soybean biodiesel, sugarcane ethanol, and switchgrass biofuels. Furthermore, the uncertainty in the land use change emissions results in a range of payback periods depending on the range of land use change emissions. Table 2.6-2 shows the different payback periods for the different biofuels and for the high and low range of land use change emissions.

**Table 2.6-2. Payback Periods for Different Fuels**

| | Payback Period (years) | | |
|---|---|---|---|
| Type of Biofuel | Low | Midpoint | High |
| Corn Ethanol (2022 average plant) | 7 | 14 | 24 |
| Soybean biodiesel | 5 | 9 | 21 |
| Sugarcane ethanol (no residue collection, no CBI) | 1 | 2 | 4 |
| Switchgrass Ethanol (biochemical) | 0 | 0 | 1 |
| Switchgrass Ethanol (thermochemical) | 1 | 1 | 2 |
| Switchgrass Diesel (F-T diesel) | 1 | 1 | 2 |

The payback periods shown in Table 2.6-2 represent the time needed for the renewable fuels to break even in terms of GHG emissions compared to the petroleum fuel replaced. However, the threshold determinations needed for the rulemaking are based on the fuels reaching a percentage reduction compared to the petroleum fuels replaced. The threshold reduction time period is longer than just the breakeven point. Table 2.6-3 shows the threshold requirements and time periods to reach those threshold reductions for each fuel.

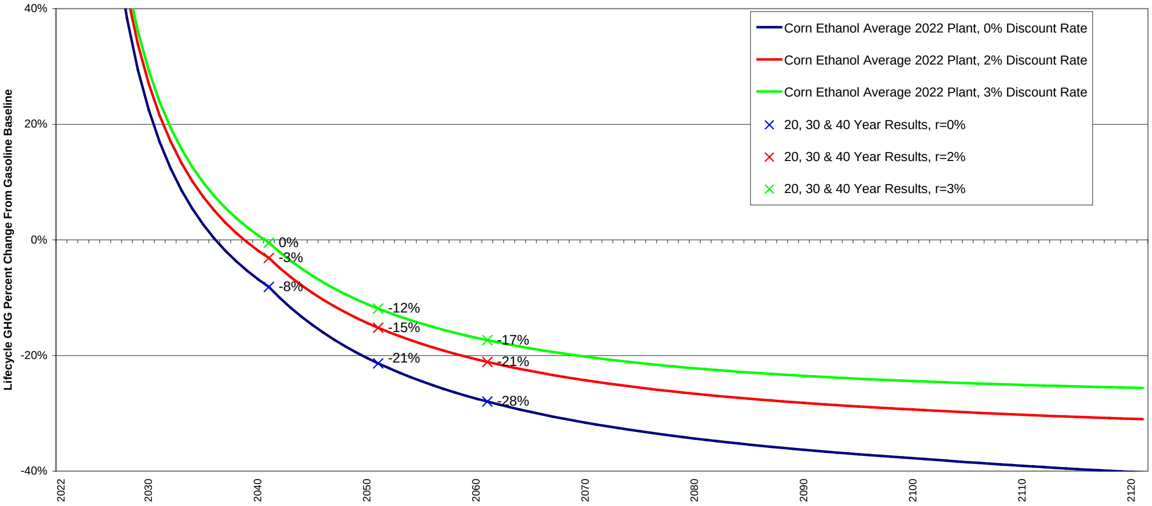
**Table 2.6-3. Threshold Periods for Different Fuels**

| | Threshold Reduction | Threshold Period (years) | | |
|---|---|---|---|---|
| Type of Biofuel | % | Low | Midpoint | High |
| Corn Ethanol (2022 average plant) | 20 | 15 | 28 | 43 |
| Soybean biodiesel | 50 | 10 | 24 | 50 |
| Sugarcane ethanol (no residue collection, no CBI) | 50 | 6 | 12 | 24 |
| Switchgrass Ethanol (biochemical) | 60 | 2 | 3 | 5 |
| Switchgrass Ethanol (thermochemical) | 60 | 7 | 12 | 24 |
| Switchgrass Diesel (F-T diesel) | 60 | 7 | 14 | 26 |

The payback period concept helps to demonstrate the importance of the choice of a discount rate and time horizon for this analysis. These factors are so important because of the variation in GHG emissions from renewable fuels over time, and the contrasting steady annual emissions from the petroleum baseline. For the final rule threshold determinations we rely on a 30 year time horizon and a 0% discount rate. A longer time horizon would result in greater benefits for biofuels, and a higher discount rate would result in lower GHG reductions.

Figure 2.6-15 includes lifecycle GHG results for the 2022 average corn ethanol produced in a natural gas-fired dry mill over a continuum of time horizons. The horizontal axis is the choice of time horizon. As discussed above, our results indicate that the payback period for an average 2022 corn ethanol pathway is approximately 14 years. With a zero percent discount (the blue line in Figure 2.6-15) corn ethanol reduces GHG emissions by 21 percent over 30 years, and reduces emissions by 8 percent and 28 percent over 20 and 40 years respectively. With higher discount rates, it takes longer for the future benefits of corn ethanol production to payback earlier land clearing emissions. When we use a discount rate greater than zero, future benefits are discounted, causing the curves in Figure 2.6-15 to flatten out over time. Results for the midpoint of land use change uncertainty are shown in Figure 2.6-15, the high and low land use change uncertainty results would shift the results. Low land use change results would shift the curves down, high land use change results would shift the curves up.

**Figure 2.6-15. Lifecycle GHG Results for 2022 Average Corn Ethanol (Percent Change from Gasoline with Different Discount Rates and Time Horizons)**



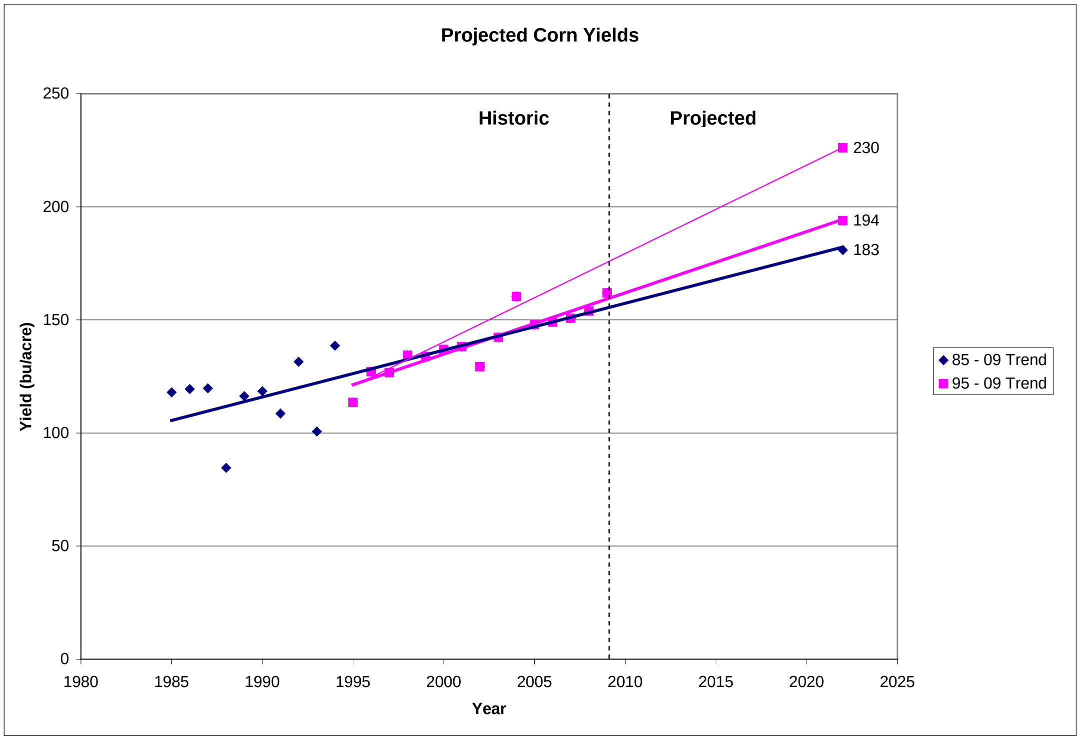
## 2.6.2.2 High Yield Scenario Results

There are many factors that go into the economic modeling but the yield assumptions for different crops has one of the biggest impacts on land use and land use change. Therefore, for this analysis we ran a base yield case and a high yield sensitivity case.

EPA's base yield projections are derived from extrapolating through 2022 long-term historical U.S. corn yields from 1985 to 2009. This estimate, 183 bushels/acre for corn and 48 bushels/acre for soybeans, is consistent with USDA's method of projecting future crop yields. During the public comment process we learned that numerous technical advancements--including better farm practices, seed hybridization and genetic modification--have led to more rapid gains in yields since 1995. In addition, commenters, including many leading seed companies, provided data supporting more rapid improvements in future yields. For example, commenters pointed to recent advancements in seed development (including genetic modification) and the general accumulation of knowledge of how to develop and bring to market seed varieties—factors that would allow for a greater rate of development of seed varieties requiring fewer inputs such as fertilizer and pest management applications.

Therefore, in coordination with USDA experts, EPA has developed for this final rule a high yield case scenario of 230 bushels/acre for corn and 60 bushels/acre for soybeans. These figures represent the 99% upper bound confidence limit of variability in historical U.S. yields. This high yield case represents a feasible high yield scenario for the purpose of a sensitivity test of the impact on the results of higher yields. Figure 2.6-16 shows the historic data and trends for U.S. corn yields.

**Figure 2.6-16. U.S. Historic and Projected Corn Yields**



Feedback we received indicated that corn and soybean yields respond in tandem and that a high yield corn case would also imply a higher yield for soybeans as well. The high yield case is therefore based on higher yield corn and soybeans in the U.S. as well as in the major corn and soybean producing countries around the world. For international yields, it is reasonable to assume the same percent increases from the baseline yield assumptions could occur as we are estimating for the U.S. Thus in the case of corn, 230 bushels per acre is approximately 25% higher than the U.S. baseline yield of 183 bushels per acre in 2022. This same 25% increase in yield can be expected for the top corn producers in the rest of the world by 2022, as justified improvements in seed varieties and, perhaps even more so than in the case of the U.S., improvements in farming practices which can take more full advantage of the seed varieties' potential. For example, seeds can be more readily developed to perform well in the particular regions of these countries and can be coupled with much improved farming practices as farmers move away from historical practices such as saving seeds from their crop for use the next year and better understand the economic advantages of modern farming practices. So the high yield scenarios would not have the same absolute yield values in other countries as the U.S. but would have the same percent increase.

Figure 2.6-17 shows the results for the 2022 average corn ethanol plant with the base and high yield scenarios. The high yield scenario has a modest change in the overall GHG reductions of corn ethanol. With the high yield estimates the 2022 average corn ethanol plant reduces GHG emissions compared to the gasoline baseline by 23%, compared to reductions of 21% for the base case scenario.

**Figure 2.6-17.**
**Distribution of High and Base Yield Results for a**
**New Natural Gas Fired Corn Ethanol Plant**
**Average 2022 plant: natural gas, 63% dry, 37% wet DGS (w/ fractionation)**

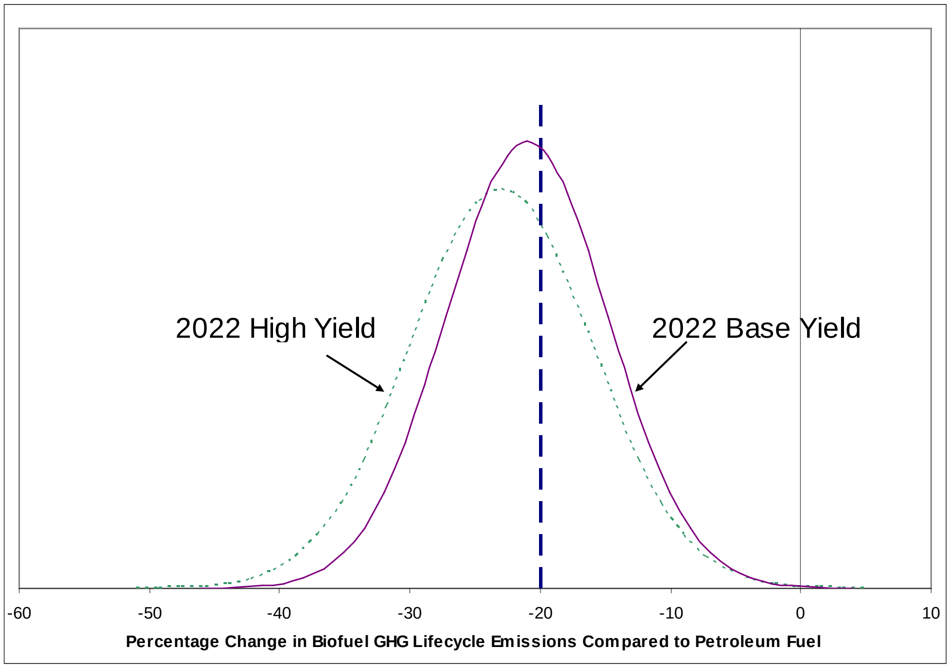
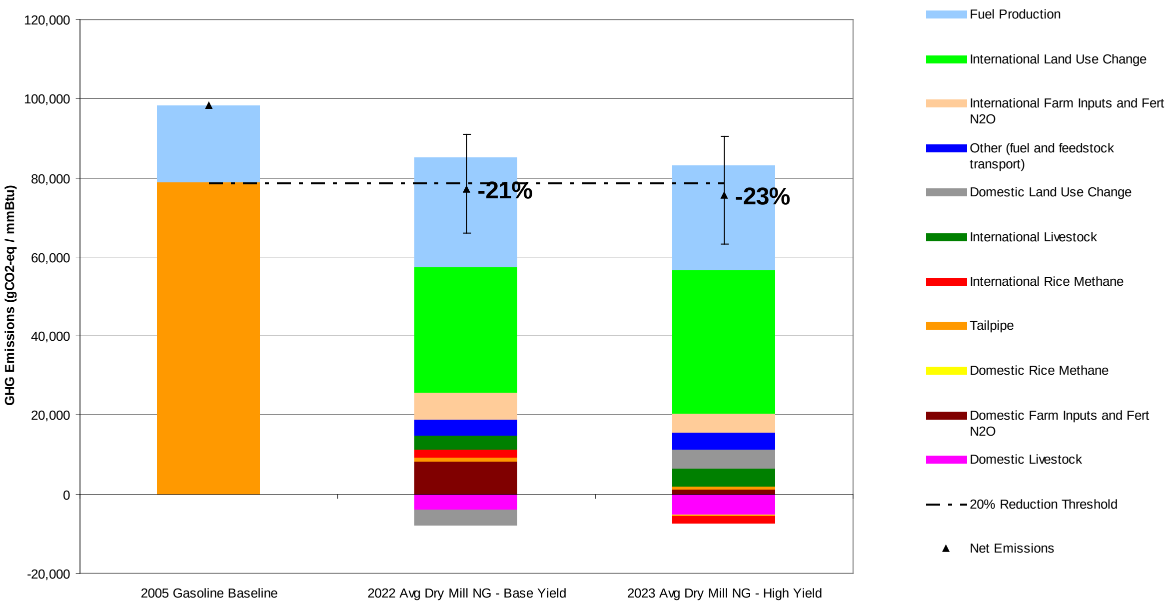


Figure 2.6-18 includes lifecycle GHG emissions broken down by several stages of the lifecycle impacts for the 2022 average corn ethanol plant for the base and high yield scenario compared to the 2005 baseline average for gasoline. Lifecycle emissions are normalized per energy unit of fuel produced and presented in grams of carbon-dioxide equivalent GHG emissions per million British Thermal Units of fuel produced (gCO2e/mmBTU).

## Figure 2.6-18.
## High and Base Yield Results for a New Natural Gas Fired Corn Ethanol Plan by Lifecycle Stage
## Average 2022 plant: natural gas, 63% dry, 37% wet DGS (w/ fractionation)



The main difference with the high yield scenario is that as ethanol production expands there is less overall land use and crop shifting needed domestically, reflected by lower domestic Farm input impacts. However, there is actually a greater impact on livestock compared to the base case. There is a greater shifting to grazing livestock internationally which results in more pasture land needed and slightly higher international land use change emissions.

Figure 2.6-19 shows the results for soybean biodiesel with the base and high yield scenarios. The high yield scenario has a fairly significant change in the overall GHG reductions of soybean biodiesel. With the high yield estimates soybean biodiesel reduces GHG emissions compared to the diesel fuel baseline by 70%, compared to reductions of 57% for the base case yield scenario.

**Figure 2.6-19. Distribution of High and Base Yield Results for Soybean Biodiesel**

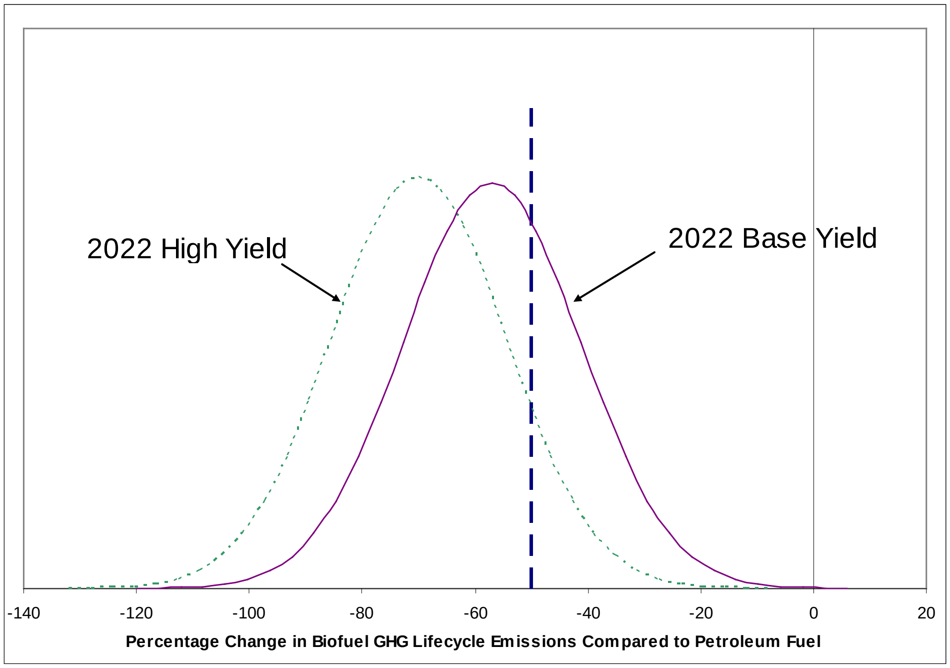
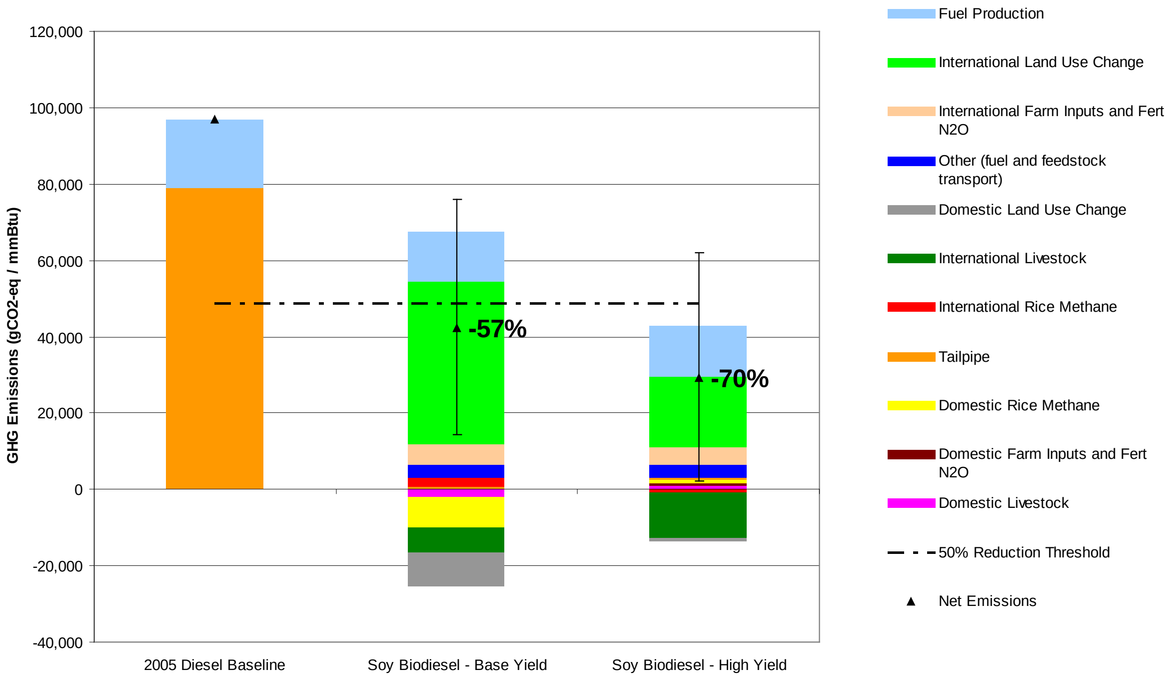


Figure 2.6-20 includes lifecycle GHG emissions broken down by several stages of the lifecycle impacts for soybean biodiesel for the base and high yield scenario compared to the 2005 baseline average for diesel fuel. Lifecycle emissions are normalized per energy unit of fuel produced and presented in grams of carbon-dioxide equivalent GHG emissions per million British Thermal Units of fuel produced (gCO2e/mmBTU).

Figure 2.6-20.  High and Base Yield Results for Soybean Biodiesel



Similar to the corn ethanol high yield scenario for the soybean high yield case the biggest impact is on livestock changes compared to the base case.  There is a greater shifting in the high yield case away from grazing livestock internationally which results in less pasture land needed and lower international land use change emissions.

## 2.7 Overall Lifecycle Greenhouse Gas Emissions Results of Rulemaking Volumes Compared to AEO Projected Volumes

Our analysis of the overall GHG emission impacts of this proposed rulemaking was performed in parallel with the lifecycle analysis performed to develop the individual fuel thresholds described in previous sections.  The same system boundaries apply such that this analysis includes the effects of three main areas: a) emissions related to the production of biofuels, including the growing of feedstock (corn, soybeans, etc.) with associated domestic and international land use change impacts, transport of feedstock to fuel production plants, fuel production, and distribution of finished fuel; b) emissions related to the extraction, production and distribution of petroleum gasoline and diesel fuel that is replaced by use of biofuels; and c) difference in tailpipe combustion of the renewable and petroleum based fuels.

Consistent with the fuel volume feasibility analysis and criteria pollutant emissions evaluation, our analysis of the GHG impacts of this proposed rulemaking was conducted by comparing the difference between a 2022 reference case and a 2022 control case with volumes of renewable fuels meeting the RFS2 mandate.  Similar to what was done to calculate lifecycle thresholds for individual fuels we considered the change in 2022 of these two volume scenarios of renewable fuels to determine overall GHG impacts of the rule.  The reference case for the

GHG emission comparisons was taken from the AEO 2007 projected renewable fuel production levels for 2022 prior to enactment of EISA. This scenario provided a point of comparison for assessing the impacts of the RFS2 standard volumes on GHG emissions. We ran these multi fuel scenarios through our FASOM and FAPRI-CARD models and applied the satellite data land use change assumptions to determine to overall GHG impacts of producing this increase in renewable fuels.

The main differences between this overall impacts analysis and the analysis conducted to develop the threshold values for the individual fuels were that we analyzed the total change in renewable fuels in one scenario as opposed to looking at individual fuel impacts. When analyzing the impact of the 2022 EISA mandate, we also took into account the agricultural sector interactions necessary to produce the full complement of feedstock.

We also considered a mix of plant types and configurations for the 2022 renewable fuel production representing the mix of plants and feedstock we project to be in use in 2022. Table 2.7-1 shows the types of plants considered and the volumes produced by each in the analysis for the references and control cases.

## Table 2.7-1. Types of Plants and Volumes Considered in 2022

| | Plant Configuration and Energy Used (Btu/gal) | | | | | | | Volume (Bgal) | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | **NG Use** | **Coal Use** | **Biomass Use** | **Diesel Fuel Use** | **Purchased Elec** | **Sold Elec** | Reference Case | Policy Case | Difference |
| Corn Ethanol – Dry Mill NG | - Base Plant (dry DDGS) | 25,672 | | | | 2,165 | | 4.2 | 5.2 | 1.0 |
| | - Base Plant (wet DGS) | 16,320 | | | | 2,165 | | 2.5 | 3.1 | 0.6 |
| | - Integrated Biogas System (dry DGS) | 11,459 | | | | 231 | | 0.9 | 1.2 | 0.2 |
| | - Integrated Biogas System (wet DGS) | 7,285 | | | | 231 | | 0.6 | 0.7 | 0.1 |
| Corn Ethanol – Dry Mill Coal | - Base Plant (dry DDGS) | | 34,773 | | | 231 | | 0.3 | 0.3 | 0.1 |
| | - Base Plant (wet DGS) | | 22,106 | | | 231 | | 0.2 | 0.2 | 0.0 |
| Corn Ethanol – Dry Mill Biomass | - Base Plant (dry DDGS) | | | 33,147 | | 1,679 | | 1.5 | 1.8 | 0.4 |
| | - Base Plant (wet DGS) | | | 21,072 | | 1,679 | | 0.9 | 1.1 | 0.2 |
| Corn Ethanol – Wet Mill | - Plant with NG | 45,950 | | | | | | 0.0 | 0.02 | 0.02 |
| | - Plant with coal | | 45,950 | | | | | 1.4 | 1.4 | 0.0 |
| Cellulosic Ethanol – Enzymatic | - Switchgrass feedstock & lignin used as fuel | | | 72,144 | | | -12,249 | 0.0 | 1.5 | 1.5 |
| | - Corn stover feedstock & lignin used as fuel | | | 68,431 | | | -12,249 | 0.2 | 1.0 | 0.7 |
| Cellulosic Ethanol – Thermochemical | - Switchgrass feedstock | | | 100,543 | 177 | | | 0.0 | 1.5 | 1.5 |
| | - Corn stover feedstock | | | 95,369 | 177 | | | 0.0 | 1.0 | 1.0 |
| Biodiesel | - Soybean oil feedstock | 18,913 | | | | 3,205 | | 0.4 | 1.4 | 1.1 |
| | - Yellow grease / tallow feedstock | 21,051 | | | | 494 | | 0.0 | 0.2 | 0.2 |
| Renewable Diesel | - Yellow grease / tallow feedstock | | | | | 838 | | 0.0 | 0.2 | 0.2 |
| Cellulosic Diesel – F-T | - Farmed trees feedstock | | | 198,429 | 327 | 13 | | 0.0 | 6.5 | 6.5 |
| Sugarcane Ethanol - CBI | - Marginal Elec | 2,592 | | 84,241 | 2,606 | | -7,287 | 0.6 | 2.2 | 1.6 |

The upstream feedstock production and processing impacts for each of the different fuel technologies were modeled based on the same assumptions used in determining the per fuel lifecycle GHG results described in previous sections.

For this overall impacts analysis we also used a different petroleum baseline fuel that is offset from renewable fuel use. The lifecycle threshold values are required by EISA to be based on a 2005 petroleum fuel baseline. For this analysis of the overall impacts of the rule we considered the crude oil and finished product that would be replaced in 2022.

For this analysis we consider that 25% of displaced gasoline will be imported gasoline and 0% of displaced diesel fuel will be imported diesel fuel. For the types of gasoline displaced we assume 65% of the displaced gasoline will be conventional gasoline and 35% will be RFG blendstock gasoline. We assume 100% of the displaced diesel fuel will be low sulfur diesel fuel.

In order to come up with GHG emissions for average crude oil used in producing gasoline and diesel fuel in 2022 we assumed 7.6% would be from tar sands and 3.8% would be from Venezuelan heavy crude. The basis for this was EIA projections for 2022[652]. EIA projects that roughly 64% of total Canadian crude oil production will be oil sand production in 2022, and that roughly 40% of total Venezuelan crude oil production will be heavy crude production in 2022. EIA also has assumptions on how much crude oil will be imported into the U.S. from Canada and Venezuela in 2022. We assumed the percentage of this imported Canadian and Venezuelan crude oil that would be oil sands and heavy oil was the same percentage of total production that is unconventional crude in those countries (~64% for Canada and ~41% for Venezuela). Based on the percent of Canadian and Venezuelan imports to total crude oil projected in 2022, oil sands represented 7.6% and heavy oil represented 3.8% of total crude oil use.

For this analysis we did not assume any efficiency improvements at the petroleum refining portion of the gasoline and diesel fuel lifecycle. Therefore the same refining energy use and emissions was assumed that was used to represent the 2005 petroleum fuel baseline. One the one hand this may be overestimating energy use and emission from petroleum refining, however, this also does not factor in recent regulations that might increase energy use and emissions, such as increased desulfurization of both gasoline and diesel fuel.

Furthermore, the tailpipe emissions changes were determined based on the specific volumes and blends of fuel considered as opposed to looking at only the difference between the renewable fuel and petroleum fuel replaced. For highway vehicles, the impact of this rule on Methane ($CH_4$) and Nitrous Oxide ($N_2O$) emissions is primarily due to vehicles switching from gasoline to E85 fuel. Based on available data, we projected no change in $N_2O$ or $CH_4$ emissions from highway vehicles that switched from conventional gasoline to E10. For diesel highway vehicles, emissions of $N_2O$ and $CH_4$ are almost one hundred times less than emissions from gasoline vehicles,[653] thus diesels were omitted from this analysis.

To estimate the inventory-wide impact, we used MOVES to model $CH_4$ and $N_2O$ for highway gasoline vehicles using reference case fuels. Because MOVES does not vary $CH_4$ and $N_2O$ emissions by temperature or by gasoline fuel properties, the model was run at the annual, national level. FFV use was assumed to be limited to light duty cars and light duty trucks. We multiplied the appropriate E85 factor by the emissions for that model year and then computed a weighted average of E85 and E10 emissions for both $CH_4$ and $N_2O$. In order to compare the results in a meaningful way, we also computed the $CO_2$ equivalent by multiplying the tons for each pollutant by the Global Warming Potential (310 for $N_2O$, 21 for $CH_4$[654]) and summing the products. The results are summarized in Table 2.7-2 below.

**Table 2.7-2. Tailpipe Nitrous Oxide and Methane Emissions in 2022**

| | Pollutant | Reference Case Tons | Control Case Tons | Percent Change |
|---|---|---|---|---|
| LDGV & LDGT | $N_2O$ | 31,447 | 29,191 | -7% |
| | $CH_4$ | 50,683 | 61,853 | 22% |
| | $CO_2$ equiv. | 10,812,803 | 10,348,003 | -4% |
| All Gasoline Highway Vehicles | $N_2O$ | 33,997 | 31,741 | -7% |
| | $CH_4$ | 55,277 | 66,447 | 20% |
| | $CO_2$ equiv. | 11,699,809 | 11,235,009 | -4% |

Given these many differences, it is clearly not possible to simply add up the individual lifecycle results described in Section 2.6 multiplied by their respective volumes to assess the overall rule impacts. The two analyses are separate in that the overall rule impacts capture interactions between the different fuels but can not be broken out into per fuels impacts, while the threshold values represent impacts of specific fuels but do not account for all the interactions.

For example, when we consider the combined impact of the different fuel volumes the overall land use change is less than when considering each fuel independently, as shown in Table 2.7-3.

**Table 2.7-3. Comparison of International Land Use Change ('000 Hectares)**

| | Considering Only Change in Soybean Based Biodiesel Fuel Volumes | Considering Only Change in Corn Ethanol Fuel Volumes | Considering Only Change in Brazilian Sugarcane Ethanol Fuel Volumes | Considering Change of all Fuel Volumes Combined |
|---|---|---|---|---|
| Land Use Change | 678.4 | 789.3 | 395.4 | 794.4 |

Overall rule impacts were determined for the different components of the lifecycle analysis as described in previous sections. The domestic agricultural sector impacts include changes in energy use GHG emissions and fertilizer / soil $N_2O$ emissions as well as changes in livestock and rice production GHG emissions.

Our analysis indicates that overall domestic agriculture emissions would increase. There is a relatively small increase in total domestic crop acres however, there are additional inputs required to grow the biofuel feedstock crops. These additional inputs result in GHG emissions from production and from $N_2O$ releases from application. This effect is somewhat offset by reductions due to lower livestock production and reductions in rice methane.

As with domestic agriculture impacts, the international agricultural sector impacts include changes in energy use GHG emissions and fertilizer / soil $N_2O$ emissions as well as changes in livestock and rice production GHG emissions. Increased crop production internationally resulted in increased fertilizer and fuel use emissions.

We estimate the largest overall agricultural sector impact is an increase in land use change impacts, reflecting the shift of crop production both domestically and internationally to meet the biofuel demand in the U.S., and land use change emissions associated with converting land into crop production.

Other portions of the biofuel lifecycle include fuel production and feedstock and fuel transport. We project reductions in GHG emissions from the renewable fuel production portion of the lifecycle due to the generation of electricity along with the increased production of cellulosic ethanol and diesel fuel.

$CO_2$ produced in the combustion of biofuels is offset by the uptake of $CO_2$ in the biomass crop used to produce the fuel, resulting in a significant net reduction of $CO_2$ compared to fossil fuel tailpipe combustion. Net carbon fluxes from changes in biogenic carbon reservoirs in wooded or crop lands associated with land use change are accounted for in the domestic and international agriculture impacts shown in upstream impacts. In addition we assume biofuel use is offsetting petroleum fuel production which also results in GHG emissions reductions from reduced upstream emissions of petroleum fuel production (crude oil extraction and transport, refining, transport).

The results of the individual lifecycle stage results can be summed to determine the overall GHG impact of the proposed rulemaking. As discussed in previous sections on lifecycle GHG thresholds there is an initial one time release from land conversion and smaller ongoing releases but there are also ongoing benefits of using renewable fuels over time replacing petroleum fuel use. Figure 2.7-1 shows the GHG emissions impact of the change in fuel volumes considered over time.

**Figure 2.7-1. GHG Impacts over time**

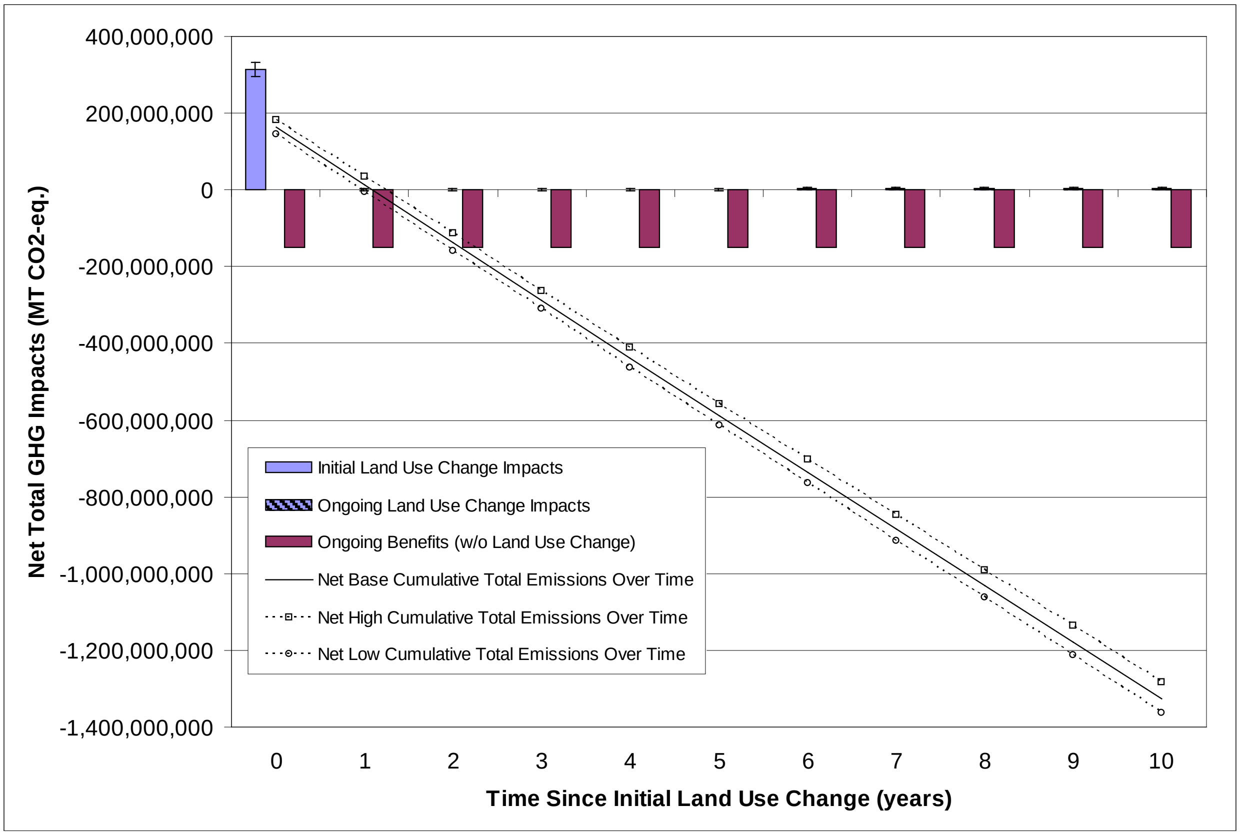


Figure 2.7-1 shows the baseline estimates for land use change as well as the range of results based on the uncertainty in the international land use change modeling. The net GHG emissions over time are also shown as a range of results based on the uncertainty in the land use change emissions.

Based on the volume scenario considered, the one time land use change impact results in a baseline estimate of 312.8 million metric tons of $CO_2$-eq. emissions with a range of 296.9 to 331.9 million metric tons $CO_2$-eq. There are however, based on the biofuel use replacing petroleum fuels, annual reduction benefits of 150 million metric tons of $CO_2$-eq. emissions. This results in a less than two year payback period before the ongoing benefits of the biofuels use offsets the initial land use impacts.

The timing of the impact of land use change and ongoing renewable fuels benefits were discussed in the previous lifecycle results section. The issue is slightly different for this analysis since we are considering absolute tons of emissions and not determining a threshold comparison to petroleum fuels. However the results can be presented in a similar manner to our individual fuels analysis in that we can determine net benefits over a 30 year time period with no discounting. Assuming a 0% discount rate over 30 years would result in an estimate of 4.15 billion tons of discounted GHG emission reductions.

Furthermore, for the calculations of the monetized GHG benefits we calculate an annualized NPV GHG reduction. This annualized value is based on converting a lump sum present value into its annualized equivalent. For this analysis we convert the NPV results into an annualized stream such that the NPV of the annualized emissions will equal the NPV of the emission stream over 30 years with a 0% discount rate. This results in an annualized emission reduction of 138.4 million metric tons of $CO_2$-eq. emissions (ranging from 136.1 to 140.3 based on uncertainty in the land use change results).

However, there may be additional indirect impacts associated with the production and use of petroleum-based fuels in the real world that are not completely captured by this analysis. For example, it is possible that renewable fuels may actually displace fuels at the margin which have higher GHG lifecycle emissions than the average (e.g., tar sands instead of conventional crude).

To examine the question of what type of marginal crude would be displaced by biofuels use, we performed an analysis using the Department of Energy's Energy Technology Perspectives (ETP) model, which is a partial equilibrium model used to analyze the international energy system. For our analysis, we created a scenario that increased domestic gasoline demand, as we wanted to isolate the impacts of petroleum use. The scenario roughly represented the additional amount of gasoline that would be required if the RFS2 renewable fuel mandates were not in effect. Our results showed that the increased gasoline demand was primarily met through production of conventional crude oil, along with a small amount of oil sands/bitumen production. The primary exporters of conventional crude oil to meet the additional demand were Middle Eastern countries. Using well-to-tank GHG values for crude extracted from various countries[655], we were able to determine an approximate "marginal petroleum baseline" by applying the factors to the countries where crude production increased. We found that the marginal baseline was, for an average gallon of gasoline, not statistically different than the average baseline value used in this final rulemaking. More details on this analysis can be found in the memo, "Petroleum Indirect Impacts Analysis" at EPA-HQ-OAR-2005-0161.

There may be other indirect impacts as well. For instance, we considered whether the displacement of petroleum fuels could also displace petroleum co-products, thus increasing the GHG reductions associated with biofuels use. When crude oil is refined to produce gasoline and diesel, petroleum co-products are also produced. Petroleum co-products include residual fuel oil and petroleum coke, which are utilized as fuels in the energy system. An increase in the demand for renewable fuels could also impact the energy system's utilization of petroleum co-products due to the ripple effects of price impacts.

While it is difficult to predict how the energy system would be affected in such an event, we expect that an increase in domestic renewable fuels demand will lead to a decrease in domestic crude oil consumption due to lower demand for gasoline and diesel. However, a decrease in demand for gasoline and diesel is unlikely to significantly impact demand for petroleum co-products unless the price for these co-products is significantly affected. Refiners respond to demand for fuels, and they may choose to produce a larger percentage of petroleum co-products per barrel of crude then they had in the past in response to lower gasoline or diesel demand. This increased supply and possible lower refinery costs could translate into a slight decrease in co-product cost and therefore marginally impact demand. We have not modeled this demand increase or what its impact might be on total GHG emissions, but we expect that it would have a negligible GHG effect for the rule overall. Thus, we are assuming no change in petroleum co-products supply and no shift in the energy system as a result.

Increased renewable fuel use domestically is expected to also have the effect of lowering the world crude oil price and therefore increase international demand for petroleum-based fuels and increase GHG emissions. As stated above, we expect that an increase in domestic renewable fuels demand will lead to a decrease in domestic crude oil demand. This decrease in U.S. oil demand could cause a decline in the world oil price, which would spur increased oil consumption abroad. This increase in demand outside of the U.S. due to price changes would partially negate the decrease in GHG emissions domestically from reduced petroleum fuel demand due to biofuels. This impact of biofuels use on crude oil imports and world crude oil price is included in our Energy Security Analysis discussed in Chapter 5.

## 2.8 Effects of GHG Emission Reductions and Changes in Global Temperature and Sea Level

The reductions in $CO_2$ and other GHGs associated with this final rule will affect climate change projections. GHGs mix well in the atmosphere and have long atmospheric lifetimes, so changes in GHG emissions will affect future climate for decades to centuries. Two common indicators of climate change are global mean surface temperature and global mean sea level rise. This section estimates the response in global mean surface temperature and global mean sea level rise projections to the estimated net global GHG emissions reductions associated with this final rule (see Section 2.7 for the estimated net reductions in global emissions over time by GHG).

EPA estimated changes in projected global mean surface temperatures to 2050 using the MiniCAM (Mini Climate Assessment Model) integrated assessment model[XXXXXXX] coupled with the MAGICC (Model for the Assessment of Greenhouse-Gas Induced Climate Change) simple climate model.[YYYYYYY] MiniCAM was used to create the globally and temporally consistent set

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[XXXXXXX] MiniCAM is a long-term, global integrated assessment model of energy, economy, agriculture and land use, that considers the sources of emissions of a suite of greenhouse gases (GHGs), emitted in 14 globally disaggregated global regions (i.e., U.S., Western Europe, China), the fate of emissions to the atmosphere, and the consequences of changing concentrations of greenhouse related gases for climate change. MiniCAM begins with a representation of demographic and economic developments in each region and combines these with assumptions about technology development to describe an internally consistent representation of energy, agriculture, land-use, and economic developments that in turn shape global emissions. Brenkert A, S. Smith, S. Kim, and H. Pitcher, 2003: Model Documentation for the MiniCAM. PNNL-14337, Pacific Northwest National Laboratory, Richland, Washington. For a recent report and detailed description and discussion of MiniCAM, see Clarke, L., J. Edmonds, H. Jacoby, H. Pitcher, J. Reilly, R. Richels, 2007. Scenarios of Greenhouse Gas Emissions and Atmospheric Concentrations. Sub-report 2.1A of Synthesis and Assessment Product 2.1 by the U.S. Climate Change Science Program and the Subcommittee on Global Change Research. Department of Energy, Office of Biological & Environmental Research, Washington, DC., USA, 154 pp.

[YYYYYYY] MAGICC consists of a suite of coupled gas-cycle, climate and ice-melt models integrated into a single framework. The framework allows the user to determine changes in GHG concentrations, global-mean surface air temperature and sea-level resulting from anthropogenic emissions of carbon dioxide (CO2), methane (CH4), nitrous oxide (N2O), reactive gases (e.g., CO, $NO_x$, VOCs), the halocarbons (e.g. HCFCs, HFCs, PFCs) and sulfur dioxide (SO2). MAGICC emulates the global-mean temperature responses of more sophisticated coupled of climate relevant variables required for running MAGICC. MAGICC was then used to estimate the change in the global mean surface temperature over time. Given the magnitude of the estimated emissions reductions associated with the proposed rule, a simple climate model such as MAGICC is reasonable for estimating the climate response.

EPA applied the estimated annual GHG emissions changes for the final rule to a MiniCAM baseline emissions scenario.[ZZZZZZZ] Specifically, the $CO_2$, $N_2O$, and $CH_4$ annual emission changes from 2022-2052 from Section 2.7 were applied as net reductions to this baseline scenario for each GHG.

The tables below provide our estimated reductions in projected global mean surface temperatures and mean sea level rise associated with the increase in renewable fuels in 2022 required by this final rule. We modeled three scenarios using different values for the estimated net global GHG reduction associated with this rule; we utilized the average, low, and high values for GHG emissions reduced, as presented in Section 2.7. To capture some of the uncertainty in the climate system, we estimated the changes in projected temperatures and sea level across the most current Intergovernmental Panel on Climate Change (IPCC) range of climate sensitivities, 1.5°C to 6.0°C.[AAAAAAAA]

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Atmosphere/Ocean General Circulation Models (AOGCMs) with high accuracy. Wigley, T.M.L. and Raper, S.C.B. 1992. Implications for Climate and Sea-Level of Revised IPCC Emissions Scenarios Nature 357, 293-300. Raper, S.C.B., Wigley T.M.L. and Warrick R.A. 1996. in Sea-Level Rise and Coastal Subsidence: Causes, Consequences and Strategies J.D. Milliman, B.U. Haq, Eds., Kluwer Academic Publishers, Dordrecht, The Netherlands, pp. 11-45. Wigley, T.M.L. and Raper,
S.C.B. 2002. Reasons for larger warming projections in the IPCC Third Assessment Report J. Climate 15, 2945-2952.

[ZZZZZZZ] The reference scenario is the MiniCAM reference (no climate policy) scenario used as the basis for the Representative Concentration Pathway RCP4.5 using historical emissions until 2005. This scenario is used because it contains a comprehensive suite of greenhouse and pollutant gas emissions including carbonaceous aerosols. The four RCP scenarios will be used as common inputs into a variety of Earth System Models for inter-model comparisons leading to the IPCC AR5 (Moss et al. 2008). The MiniCAM RCP4.5 is based on the scenarios presented in Clarke et al. (2007) with non-$CO_2$ and pollutant gas emissions implemented as described in Smith and Wigley (2006). Base-year information has been updated to the latest available data for the RCP process.

[AAAAAAAA] In IPCC reports, equilibrium climate sensitivity refers to the equilibrium change in the annual mean global surface temperature following a doubling of the atmospheric equivalent carbon dioxide concentration. The IPCC states that climate sensitivity is “likely” to be in the range of 2°C to 4.5°C and described 3°C as a "best estimate." The IPCC goes on to note that climate sensitivity is “very unlikely” to be less than 1.5°C and “values substantially higher than 4.5°C cannot be excluded.” IPCC WGI, 2007, *Climate Change 2007 - The Physical Science Basis,* Contribution of Working Group I to the Fourth Assessment Report of the IPCC, http://www.ipcc.ch/.

### Table 2.8-1.
### Estimated Reductions in Projected Global Mean Surface Temperature and Global Mean Sea Level Rise from Baseline for the Average Case for the Final Rule in 2020-2050

| Climate Sensitivity | | | | | | |
|---|---|---|---|---|---|---|
| | 1.5 | 2 | 2.5 | 3 | 4.5 | 6 |
| **Year** | **Change in global mean surface temperatures (degrees Celsius)** | | | | | |
| 2020 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| 2025 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| 2030 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| 2035 | -0.001 | -0.001 | -0.001 | -0.001 | -0.001 | -0.001 |
| 2040 | -0.001 | -0.001 | -0.001 | -0.001 | -0.001 | -0.001 |
| 2045 | -0.001 | -0.001 | -0.001 | -0.001 | -0.002 | -0.002 |
| 2050 | -0.001 | -0.001 | -0.002 | -0.002 | -0.002 | -0.002 |
| **Year** | **Change in global mean sea level rise (centimeters)** | | | | | |
| 2020 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| 2025 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| 2030 | -0.001 | -0.001 | -0.001 | -0.001 | -0.001 | -0.001 |
| 2035 | -0.002 | -0.002 | -0.002 | -0.003 | -0.003 | -0.003 |
| 2040 | -0.003 | -0.004 | -0.004 | -0.005 | -0.005 | -0.006 |
| 2045 | -0.005 | -0.006 | -0.006 | -0.007 | -0.008 | -0.009 |
| 2050 | -0.006 | -0.008 | -0.009 | -0.009 | -0.011 | -0.012 |

### Table 2.8 2.

### Estimated Reductions in Projected Global Mean Surface Temperature and Global Mean Sea Level Rise from Baseline for the Low Case for the Final Rule in 2020-2050

| | **Climate Sensitivity** | | | | | |
|---|---|---|---|---|---|---|
| | 1.5 | 2 | 2.5 | 3 | 4.5 | 6 |
| **Year** | **Change in global mean surface temperatures (degrees Celsius)** | | | | | |
| 2020 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| 2025 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| 2030 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| 2035 | -0.001 | -0.001 | -0.001 | -0.001 | -0.001 | -0.001 |
| 2040 | -0.001 | -0.001 | -0.001 | -0.001 | -0.001 | -0.001 |
| 2045 | -0.001 | -0.001 | -0.001 | -0.001 | -0.002 | -0.002 |
| 2050 | -0.001 | -0.001 | -0.002 | -0.002 | -0.002 | -0.002 |
| **Year** | **Change in global mean sea level rise (centimeters)** | | | | | |
| 2020 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| 2025 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| 2030 | -0.001 | -0.001 | -0.001 | -0.001 | -0.001 | -0.001 |
| 2035 | -0.002 | -0.002 | -0.002 | -0.003 | -0.003 | -0.003 |
| 2040 | -0.003 | -0.004 | -0.004 | -0.005 | -0.005 | -0.006 |
| 2045 | -0.005 | -0.006 | -0.006 | -0.007 | -0.008 | -0.009 |
| 2050 | -0.006 | -0.008 | -0.009 | -0.009 | -0.011 | -0.012 |

### Table 2.8-3.
### Estimated Reductions in Projected Global Mean Surface Temperature and Global Mean Sea Level Rise from Baseline for the High Case for the Final Rule in 2020-2050

| Climate Sensitivity | | | | | | |
|---|---|---|---|---|---|---|
| | 1.5 | 2 | 2.5 | 3 | 4.5 | 6 |
| **Year** | **Change in global mean surface temperatures (degrees Celsius)** | | | | | |
| 2020 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| 2025 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| 2030 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| 2035 | -0.001 | -0.001 | -0.001 | -0.001 | -0.001 | -0.001 |
| 2040 | -0.001 | -0.001 | -0.001 | -0.001 | -0.001 | -0.001 |
| 2045 | -0.001 | -0.001 | -0.001 | -0.001 | -0.002 | -0.002 |
| 2050 | -0.001 | -0.001 | -0.002 | -0.002 | -0.002 | -0.002 |
| **Year** | **Change in global mean sea level rise (centimeters)** | | | | | |
| 2020 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| 2025 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 | 0.000 |
| 2030 | -0.001 | -0.001 | -0.001 | -0.001 | -0.001 | -0.001 |
| 2035 | -0.002 | -0.002 | -0.002 | -0.003 | -0.003 | -0.003 |
| 2040 | -0.003 | -0.004 | -0.004 | -0.004 | -0.005 | -0.006 |
| 2045 | -0.005 | -0.006 | -0.006 | -0.007 | -0.008 | -0.008 |
| 2050 | -0.006 | -0.007 | -0.008 | -0.009 | -0.011 | -0.012 |

The results in table above show small reductions in the global mean surface temperature and sea level rise projections across all climate sensitivities. Overall, the reductions are small relative to the IPCC's "best estimate" temperature increases by 2100 of 1.8ºC to 4.0ºC.[656] Although IPCC does not issue "best estimate" sea level rise projections, the model-based range across SRES scenarios is 18 to 59 cm by 2099.[BBBBBBBB] While the distribution of potential temperatures in any particular year is shifting down, the shift is not uniform. The magnitude of the decrease is larger for higher climate sensitivities. The same pattern appears in the reductions in the sea level rise projections. For instance, in 2050, the reduction in projected temperature (for all cases) for climate sensitivities of 3 and 6 is approximately 50% and 99% greater than the reduction for a climate sensitivity of 1.5. The same pattern appears in the reductions for the sea level rise projections.[CCCCCCCC]

Thus, we can conclude that the impact of this final rule is to lower the risk of climate change, as the probabilities of temperature increase and sea level rise are reduced.

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[BBBBBBBB] "Because understanding of some important effects driving sea level rise is too limited, this report does not assess the likelihood, nor provide a best estimate or an upper bound for sea level rise." IPCC Synthesis Report, p. 45

[CCCCCCCC] In 2050, the reduction in projected sea level rise (for all cases) for climate sensitivities of 3 and 6 is approximately 45% and 86% greater than the reduction for a climate sensitivity of 1.5.

# Chapter 3: Impacts of the Program on Non-GHG Pollutants

In addition to the GHG impacts laid out in Chapter 2, we project that the increased use of renewable fuels required by RFS2 will affect emissions of “criteria” pollutants (those pollutants for which a National Ambient Air Quality Standard has been established), criteria pollutant precursors, and air toxics. Changes in these emissions would derive from the direct effect of renewable fuels on the tailpipe and evaporative emissions of vehicles and off-road equipment; and increased renewable fuel production and distribution including the effect of decreases in the production and distribution of gasoline and diesel displaced by renewable fuel. For this analysis we have focused on estimating the change in mass emissions for these pollutants across the entire U.S. in 2022, when the program is fully implemented, and we have also conducted a full-scale air quality modeling and health impact assessment that accounts for geographic differences in impacts at the county level. This chapter presents national emission impacts for nitrogen oxides (NOx), volatile organic compounds (VOC), carbon monoxide (CO), particulate matter 10 microns in diameter and less (PM10), particulate matter 2.5 microns in diameter and less (PM2.5), sulfur dioxide (SO2), ammonia (NH3), benzene, 1,3-butadiene, acrolein, formaldehyde, acetaldehyde, naphthalene, and ethanol, including the methodology for developing these estimates. Section 3.3 discusses the differences between the final rule emission inventories presented in Sections 3.1 and 3.2 compared to the inventories that were used for air quality modeling. Section 3.4 of this chapter presents the methodology and results of air quality modeling, and Sections 3.5 and 3.6 address health and environmental impacts of today's rule.

## 3.1 Methodology for Calculating Non-GHG Emission Impacts

Our analysis focused on the projected impact of the renewable fuel volumes required in 2022, the first year the RFS2 program is fully implemented. The emission impacts of the 2022 RFS2 volumes are quantified in Section 3.2 for a range of renewable fuel scenarios relative to two reference cases discussed in detail above in Section 1.2.1. In order to allow assessment of total emission impacts of mandated renewable fuel volumes, the main reference case presented in this analysis was the RFS1 mandate volume of 7.5 billion gallons of renewable fuel (6.7 billion gallons ethanol). We are also presenting impacts relative to the 13.6 billion gallons of renewable fuels projected by the Department of Energy (DOE) Annual Energy Outlook (AEO) 2007 to show the impact of the RFS2 renewable fuel volumes incremental to the projected renewable market pre-EISA.

Our analysis of non-GHG emissions impacts was comprised of a) an analysis of direct impacts on motor vehicles, off-road equipment and other sources from burning (or evaporating) renewable fuels in place of petroleum-based fuels; and b) the emissions impacts from the production and distribution of renewable fuels. These analyses are discussed separately in Sections 3.1.1 and 3.1.2.

### 3.1.1 Impact on Non-GHG Emissions from Motor Vehicles and Equipment

The volumes of renewable fuel called for in today's rule will directly affect emissions from most mobile source categories, and for this analysis we have quantified the effects on exhaust and evaporative emissions of gasoline-fueled vehicles and equipment including passenger cars, light trucks, heavy trucks, motorcycles and off-road sources such as lawn mowers, recreational boats and all-terrain vehicles. We have also estimated the impact of ethanol on emissions from portable fuel containers, and increased refueling emissions due to higher volatility of ethanol-blended fuel and increased refueling events due to lower energy content of biofuels. The emissions impacts of biodiesel were also estimated on heavy-duty diesel vehicles, assuming additional biodiesel would be burned by on-road sources only.

A considerable source of uncertainty in estimating the emission impacts of renewable fuels is the effect ethanol blends will have on emissions of cars and light trucks. Under today's action every gasoline vehicle and piece of equipment would be fueled on at least E10. For the proposal, the uncertainty in the emission impacts of E10 was reflected by showing emission impacts under two cases representing different levels of sensitivity in the emissions of cars and light trucks to ethanol. In the final rule, we are reflecting preliminary results from work sponsored by EPA and DOE which suggests that emissions from Tier 2 vehicles show little sensitivity to E10.[657] In addition to E10, many flexible-fueled passenger vehicles may need to be operated on E85 to consume the increased volumes of renewable fuels. The amount of E85 needed will depend on the volume of ethanol as opposed to other renewable fuels utilized in the future. Data on E85 continues to be limited, and emission results have shown large variability of emission effects in some pollutants. As a result, for the final rule we have decided to assign no emission effect to the use of E85, except for the emissions of acetaldehyde and ethanol.

For the analysis of all gasoline-fueled highway vehicles except motorcycles, a preliminary version of MOVES2010 was used to generate national inventories for the control and reference cases modeled for the RFS2 final rule. This version reflected updates to fuel effects made to the model since the analysis for the proposal and air quality modeling versions, based on data made available since these analyses were performed; these fuel effect updates were eventually finalized in the recently released version of MOVES2010.[658],[659] We decided to use a draft version of MOVES for this analysis to begin to reflect significant updates in emissions, and in particular fuel effects, from MOBILE6. As the other mobile source categories in MOVES were still under development at the time of this analysis, all onroad diesel, motorcycle and off-road equipment emissions were calculated with the National Mobile Inventory Model (NMIM), a platform which generates emission inventories based on EPA's MOBILE6 and NONROAD models.

The development of vehicle and equipment emission impact estimates for today's rule required: a) developing fuel supply inputs at the county level for the 2005 base year and 2022 reference and control cases which accounted for the projected change in fuel properties due to today's action; b) developing individual vehicle fuel effects; and c) running MOVES and NMIM to produce raw inventory estimates and post-processing these results as needed to account for different baselines, to apply "off model" corrections, or to estimate impacts not accounted for in the models. Each of these steps are detailed in the following sections

#### 3.1.1.1 Fuel Inputs

As inputs to our emissions modeling, we developed a detailed profile of fuels for each modeling case. We prepared county-level databases of fuel properties and fuel market shares for the 2005 base case, the RFS1 reference case, the 2022 AEO reference case, and the 2022 control case. These county-level databases were applied in both NMIM and MOVES for consistency in fuel inputs across the different mobile source categories.

The 2005 base case fuel properties were derived from 2005 historical data. These data included national summer and winter fuels surveys, studies that tracked the total amount of ethanol produced for use in gasoline each year, and Reformulated Gasoline (RFG) surveys. Additional data were available on the fuel properties of all gasoline produced and imported annually by refiners, and on the distribution of gasoline to and from Petroleum Administration for Defense Districts (PADDs). Where survey data was available, it was used to determine a county's fuel properties for summer and winter. Where survey data was not available, fuel properties were set to equal the average fuel properties in that PADD. Special adjustments were made to some counties to account for local gasoline volatility control programs and winter oxygenated gasoline programs.

For the 2022 reference and control cases, the 2005 base case fuel properties were adjusted to account for implementation of other fuel regulations and to account for increased ethanol use. There is a greater percentage of ethanol in both the 2022 RFS1 and AEO 2007 reference cases than in the 2005 base case because methyl tert-butyl ether (MTBE) has been replaced with ethanol and because of increased ethanol usage mandated by RFS1 (the RFS1 reference case), and AEO-projected growth in ethanol production for 2022 (the AEO 2007 reference case). For this analysis, ethanol was allocated to the state and county level based on the economics of distribution and blending, as well as other factors (refer to Section 1.7.1 of this document for details). The 2022 control cases model three different approaches to meeting the renewable fuel volume requirements of EISA. Even in the low ethanol control case (17.5 billion gallons of ethanol), there would be enough ethanol in the fuel supply to require use of at least 10 percent ethanol (E10) in every county, while the choice of counties modeled with E85 was based on the economics and other factors.

Future fuel properties in both the reference and control cases were adjusted to account for widespread increases in ethanol. This was done using two assumptions: 1) ethanol has historically been splash blended in conventional gasoline (CG), and 2) it will be match-blended by 2022 (i.e., the changes associated with ethanol addition will be accounted for by refiners when producing the base gasoline). We believe this is reasonable given that there will be a large (and thus more geographically predictable) volume of ethanol used in gasoline, and that certain property changes that take place when ethanol is blended (such as octane increase) could be economically beneficial to refiners if they can be assumed when producing the base gasoline. Thus, we adjusted aromatics, olefins, T50, and T90 fuel parameters by first backing out the effects of any existing oxygenate (by reverse dilution), and then re-adjusting the properties for ethanol blends based on refinery modeling done for the RFS1 rulemaking that projected how gasoline properties were likely to change given widespread use of ethanol. Table 3.1-1 shows the adjustment factors used per volume percent ethanol blended. Reid Vapor Pressure (RVP) was increased 1.0 psi wherever ethanol was present in conventional gasoline unless there was a local volatility control.

**Table 3.1-1. 2022 Adjustments for Ethanol Added to Conventional Gasoline**

| Additive change per vol% ethanol added | Aromatics (vol%) | Olefins (vol%) | E200 (vol%) | E300 (vol%) |
|---|---|---|---|---|
| Summer | -0.69 | 0.00 | 1.10 | 7.52 |
| Winter | -0.68 | 0.00 | 0.78 | 7.21 |

For example, the adjusted summer aromatics value would be calculated as follows:

*Current aromatics value – dilution effect of current ethanol level due to splash blending + (new volume percent ethanol x -0.69 for match blend effect)*

For Reformulated Gasoline (RFG) areas, refiners already account for the blending of ethanol when producing the base gasoline, and therefore the properties are not predicted to change in the same ways as for conventional gasoline (CG). We used refinery modeling results for each PADD (produced using the same cases and renewable fuel volumes as described above for CG) to project the properties of fuel in RFG areas. RFG properties used in the reference and control cases in 2022 are shown here in Table 3.1-2. The 2022 reference and control cases also incorporate reductions in gasoline sulfur resulting from Tier 2 regulations. Fuel benzene levels presented in this table have been updated from what was used in the NPRM to reflect the 2007 mobile source air toxics (MSAT) rule, which mandates a 0.62% fuel benzene standard.[660]

**Table 3.1-2. 2022 Reformulated Gasoline Properties by PADD**

| PADD [a] | RVP (psi) | Aromatics (vol%) | Benzene (vol%) | Olefins (vol%) | E200 | E300 |
|---|---|---|---|---|---|---|
| Summer | | | | | | |
| 1 | 7.0 | 19.9 | 0.54 | 8.1 | 52 | 95 |
| 2 | 7.0 | 18.8 | 0.60 | 6.8 | 52 | 95 |
| 3 | 7.0 | 18.4 | 0.55 | 5.6 | 51 | 95 |
| 5 | 6.8 | 21.5 | 0.62 | 5.7 | 54 | 86 |
| Winter | | | | | | |
| 1 | 13.2 | 19.9 | 0.54 | 14.1 | 58 | 95 |
| 2 | 13.1 | 20.0 | 0.60 | 11.9 | 62 | 95 |
| 3 | 11.8 | 19.8 | 0.55 | 13.0 | 55 | 95 |
| 5 | 11.4 | 21.9 | 0.62 | 5.7 | 60 | 86 |

[a] There are no RFG areas in PADD 4.

Unlike the proposal, for the final rule we did not model the effects of flexible-fueled vehicles running on E85 for any pollutants except acetaldehyde and ethanol.

For each of the modeled scenarios, fuel information was input into an NMIM database and used for NMIM runs. For MOVES runs, the NMIM databases were converted into MOVES databases using a conversion program. To reduce time needed for MOVES runs, we reduced the size of the MOVES fuel database by processing the database with a "binner" program that grouped fuels with similar properties and assigned each group to a single fuel formulation identification number and a single set of fuel properties. A significant update to MOVES between the proposal and final rulemaking was the inclusion of direct calculation of fuel adjustments that allowed less aggregation in this binning approach, thus improving the resolution of fuel-based emission impacts.

### 3.1.1.2 Effect of Fuels on Non-GHG Emissions from Vehicles & Equipment

The average effect of renewable fuels on an individual vehicle/equipment basis, based on available research, is the foundation of the emission impact assessment. This section contains discussion of the effects used in the emission impact assessment for E10 on gasoline vehicles and equipment, for E85 on gasoline vehicles, and for biodiesel.

#### 3.1.1.2.1 On-road Gasoline Vehicle E10 Effects

#### 3.1.1.2.1.1 Exhaust Emissions

Ethanol blends can affect exhaust emissions from vehicles and off-road equipment. A comprehensive analysis of E10 impacts on exhaust emissions was undertaken for the RFS1 rule, as documented in Chapter 3 of the RFS1 Regulatory Impact Analysis.[661] This analysis considered previous EPA work in coming up with a so-called “Predictive Model” to assess California’s request for an oxygenate waiver in 2000, as well as test data from several test programs conducted by the auto trade associations (AAM/AIAM), ExxonMobil, Toyota, and the Mexican Petroleum Institute. This assessment concluded that for Tier 1 and later vehicles (nominally model year 1996 and later, comprising the majority of the fleet in 2022) there was not enough consistency across these studies to confidently predict the impact of oxygenated fuel on exhaust HC and NOx emissions. As a result the RFS1 analysis carried forward two sets of fuel effects: a “primary” analysis assuming no effect of oxygen on non-methane hydrocarbon (NMHC) and NOx emissions from Tier 1 and later vehicles, and a “sensitivity” analysis which applied EPA’s Predictive Model effects to Tier 1 and later vehicles. For the RFS2 proposal we characterized ethanol effect scenarios: “less sensitive” based on the “primary” case used in RFS1, and “more sensitive” based on the RFS1 “sensitivity” case.

We are now nearing completion of a large scale testing effort aimed at quantifying the effects on exhaust and evaporative emissions from Tier 2 vehicles of ethanol and several other fuel properties impacted by the blending of ethanol into gasoline.[662] Based on analysis of preliminary data from this test program, we are carrying forward effects that more closely reflect the "less sensitive" case, which does not apply any E10 effects to NOx or HC emissions for later model year vehicles, or E85 effects for most pollutants. While the effects of E10 on individual vehicles will vary depending on properties of the fuel (e.g., RVP, distillation, and aromatic content), Table 3.1-3 demonstrates the effects used for conventional and reformulated gasoline based on the fuel properties derived from Tables 3.1-1 and 3.1-2. For the “less sensitive” case for the proposal, the effects shown for NOx, HC and toxics were applied to only Tier 0 vehicles (mid 1990’s and older); in our analysis for this final rule, we extended these effects to Tier 1 and

NLEV cars and light trucks (through the 2003 model year) based on a recently published study from CRC.[663] However, our preliminary analysis of the EPA/DOE test program did not justify attributing these effects to Tier 2 vehicles.

**Table 3.1-3. Exhaust Effect of E10 Relative to E0 for Pre-Tier 2 Vehicles [a]**

| **Pollutant** | **Source** | **CG** | **RFG** |
|---|---|---|---|
| Exhaust HC (VOC) | EPA Predictive Models | -7.4% | -9.7% |
| NOx | | 7.7% | 7.3% |
| CO[b] | MOBILE6.2 | -11% / -19% | -36% |
| Exhaust Benzene | EPA Predictive and Complex Models | -24.9% | -38.9% |
| Formaldehyde | | 6.7% | 2.3% |
| Acetaldehyde | | 156.8% | 173.7% |
| 1,3-Butadiene | | -13.2% | 6.1% |

[a] Assumes summer (July) conditions

[b] The first figure shown applies to normal emitters; the second applies to high emitters.

### 3.1.1.2.1.2 Evaporative Emissions

While E10 affects evaporative emissions from gasoline vehicles due to the increased volatility of E10 blends, the increased permeation of fuel vapors through tanks and hoses, and the increased vapor emissions due to the lower molecular weight of E10, for cars and light trucks by far the largest of these effects is permeation. For the final rule, we estimated only the impact of permeation using updated estimates in the draft MOVES model, which separates permeation emissions from vapor venting emissions to allow better accounting for this effect.

For the proposal, permeation effects were developed from Coordinating Research Council's (CRC) E-65 program[664], which measured evaporative emissions from ten fuel systems that were removed from the vehicles on E0 and E5.7 fuels; fuel systems were removed to ensure that all evaporative emissions measured were from permeation of the fuel through the different components of the fuel system. For that analysis, we estimated the effect by calculating the percent increase in average emissions from all vehicles between E0 and E5.7 fuels over the 65 to 105 degree Fahrenheit diurnal test. That value was 46 percent. In order to estimate the effect at E10 we simply multiplied this result by 1.75 (10/5.7), resulting in a 79 percent increase applied to cars and light trucks from all model years. That approach heavily weighted the emission contribution of older vehicles in the test program, and, in conjunction with lower emission rates for vehicles certified to Enhanced Evaporative and later standards in MOVES, served to underestimate the impact of E10 on permeation from newer vehicles.

The version of MOVES used for the FRM analysis significantly updates the permeation estimate used in the NPRM, particularly for newer technology vehicles, based on data collected by CRC in the followup E-65 program (E-65.3) and as part of their more recent E-77 series of evaporative emissions programs This new data allowed us to make a distinction between the relative impact of E10 on vehicles certified to the enhanced evaporative and later standards, vs. older technology vehicles. The data showed a significant change in the relative impact of E10, from a 65 percent increase for pre-enhanced vehicles, to a 213 percent increase for newer technology vehicles.[665] This analysis also confirmed the E-65.3 finding that there is no significant difference between emission effects on E5.7 and E10.

#### 3.1.1.2.2 On-road Gasoline vehicle E85 effects

In the proposal, the "more sensitive" case included impacts of E85 on several pollutants, based on analysis of limited data from EPA and Environment Canada. For the final rule we have decided not to apply these effects to the potential increase in E85 use, with the exception of acetaldehyde and ethanol. The rationale for this is the large range of uncertainty imposed by the limited nature of the dataset. EPA expects more data to become available to help assess this issue for future analyses, as CRC, EPA and DOE are all engaged in programs that will expand this dataset. We are including the discussion of E85 data considered in this RIA to provide documentation of available data; no new information is presented here relative to the proposal, as no new data has been generated in the interim. The only difference between proposal and final is that, of the effects determine in this analysis, only acetaldehyde and ethanol were included in the final rule inventories.

For this analysis we identified three recent data sources that investigate the effects of E85 on current technology (i.e. Tier 2 and similar) vehicles[DDDDDDDD].[666, 667, 668] Two of these sources are test programs conducted by Southwest Research Institute and Environment Canada, and the third is EPA certification data. This section briefly describes each data source and highlights the key findings, and explains how these data were used to generate E85 effects.

In 2006, Southwest Research Institute (SwRI) conducted a study for EPA on three model year 2005 Tier 2 FFVs (bins 5 and 8) operating on several gasoline and ethanol blends. This study was primarily focused on the impacts of fuel ethanol content and reduced ambient test temperature (tests were conducted at 75ºF and 20ºF) on VOC and PM emissions. Multiple fuel blends were evaluated in this program, although for this analysis we will focus only on E0 and E85 emissions at 75º F. At this test temperature, Tier 2 certification fuel was used as the non-oxygenated test fuel (E0) as well as the base gasoline for the splash-blended E10 and E85 fuels. Additionally, EPA certification "cold CO" wintertime gasoline was used for reduced ambient temperature (20 ºF) testing – used alone (E0) and as the base fuel for wintertime E10 and E70 blends. This base gasoline has a higher RVP than its summertime equivalent, which is necessary to ensure proper fuel vaporization at lower ambient temperatures. Repeat tests were conducted for the 20ºF tests on the winter fuel blends, but no repeats were run for 75ºF testing. In addition to the regulated pollutants, SwRI measured CO2, CH4, benzene, 1,3-butadiene, naphthalene, acetaldehyde, acrolein, and ethanol. This study saw reductions in PM 2.5, benzene, and 1,3-butadiene of 55% - 70% with E85 relative to E0. HC emissions increased while NOx and CO decreased. Emissions of methane, formaldehyde, and acetaldehyde were found to increase significantly with E85 use. Table 3.1-6 summarizes the average percent change in emissions with E85 vs. E0. This table also compares the findings of this dataset with the other two programs described below.

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[DDDDDDDD] EPA is aware of several test programs, either planned or underway, by CRC and others that may provide additional test data for future fuel effects modeling and rulemaking support.

Environment Canada released a report in 2005 in which an NLEV and an interim non-Tier 2 vehicle were tested on Tier 2 certification fuel and a commercially available E85 blend. Repeat tests were conducted in this study so that each vehicle was tested three times on each fuel. The pollutants measured include NMOG, NMHC, CO, NOx, CO2, CH4, N20, benzene, 1,3-butadiene, acetaldehyde, formaldehyde, acrolein, and ethanol, among others. The results, summarized in Table 3.1-6 showed statistically significant reductions in CO and NOx (-48% and -40%, respectively) when switching from E0 to E85. E85 caused non-methane organic gases (NMOG) emissions to increase in one vehicle and decrease in the other. Toxics reductions were of a similar order of magnitude as the vehicles tested in the SwRI study discussed above

EPA's Certification and Fuel Economy Information System (CFEIS) database was accessed to identify data from five model year 2006 Tier 2 vehicles (bins 5, 8, and 9) tested on both E85 and Tier 2 certification gasoline. The E85 blend tested here was 85% denatured ethanol splash blended with 15% Tier 2 certification gasoline. Each vehicle was only tested once on each fuel. Weighted FTP results were reported for the regulated pollutants (except PM) as well as CO2, acetaldehyde, and ethanol (formaldehyde, acetaldehyde, and ethanol were only measured for tests where E85 was used; therefore these are expressed as fractions of NMOG here). This data indicates that E85 causes a slight increase in NMOG emissions, a slight decrease in NOx and CO2, and significant reductions in CO. The average percent change in each pollutant for these vehicles when operated on E85 is shown in Table 3.1-5, below.

**Table 3.1-5.**
**Effect of E85 on LEV and Later Per-mile Exhaust Emissions Relative to Conventional Gasoline: Percent change separated by data source**

| | EPA – CFEIS | EPA - SwRI | Env. Canada |
|---|---|---|---|
| **NMOG** | 10% | 87% | 5% |
| **CO** | -34% | -15% | -48% |
| **NOx** | -3% | -42% | -40% |
| **Benzene** | NA | -61% | -65% |
| **1,3 Butadiene** | NA | -66% | -74% |
| **Acetaldehyde** | 12% of NMOG | 5600% | 3121% |
| **Formaldehyde** | 2% of NMOG | 116% | 98% |
| **Acrolein (E85 mg/mile emissions)** | NA | 0.023 | 0.010 |
| **Unburned Ethanol (E85 mg/mile emissions)** | 28.3 (55% of NMOG) | 25.4 (33% of NMOG) | 34.6 (48% of NMOG) |
| **PM 2.5** | NA | -68% | NA |

Viewed independently, each study provides only limited insight on the effects of E85 on emissions relative to E0. Table 3.1-5 shows that while changes in some pollutants compare reasonably well between studies, others can vary widely. This makes it difficult to determine quantitative trends in emissions, since calculating an average percent change in emissions across all three studies does nothing to address the variability of the test data. Without this assessment of variability there is no way to estimate the statistical significance of the reported values. Only the Environment Canada conducted the repeat tests necessary to assess the test-to-test variability of a given vehicle, and none of the studies tested enough vehicles to confidently state that their findings can be applied to the Tier 2 FFV fleet as a whole. This clearly illustrates the need for additional testing in this area.

The fact that Environment Canada tested non-Tier 2 vehicles is noteworthy. The 2004 Chrysler Sebring was an interim non-Tier 2 bin 8 vehicle. Despite its name, however, the standard is equivalent to the final Tier 2 bin 8 FTP standards in all areas but the full useful life (120K miles vs. 100K miles). In fact this vehicle was cleaner than required by the standard, with observed emissions on E0 at the level of a Tier 2 bin 7 vehicle. The second vehicle tested by Environment Canada was a 2002 Dodge Caravan certified to the NLEV LEV LDT level. The standards at this certification level are considerably more relaxed than Tier 2 levels for some pollutants but not others. While these vehicles share the same NMOG certification standard (0.100 g/mi), the CO standard is roughly 30% higher and the NOx standard nearly 4 times higher than the Tier 2 bin 8 level. As a result of this difference in standards, the Caravan emitted about 20% more CO and 2.5 times more NOx than the Sebring. NMOG emissions were nearly the same for both vehicles with non-oxygenated gasoline. On a relative scale, both vehicles experienced similar percent changes in emissions between E0 and E85. The Sebring emitted more ethanol with E85 than did the Caravan, resulting in a higher E85 NMOG emissions factor for that vehicle.

The variability in the magnitude of these changes, however, is what weakens the analysis. Had additional observations been made, these results may have become more significant for more pollutants. For this final rule analysis we are only modeling emission effects with use of E85 in flex-fueled vehicles relative to E0 for two of the pollutants: ethanol and acetaldehyde, for which data suggests the effects are more certain. For the “more sensitive case” presented in the NPRM, and used in the air quality modeling, we had estimated changes to additional pollutants (including significant PM reductions) based on the limited data from the studies discussed above. However, until such time as additional data is collected to enhance this analysis we believe it is premature to use such assumptions.

The “more sensitive” case in the NPRM also included a 50 percent reduction in evaporative emissions with use of E85 based on results from just one vehicle from CRC’s E-65 evaporative permeation program. Given the variability in not only vehicles, but also E85 volatility in-use, we do not believe it appropriate to rely on just one data point, and as a result this reduction was also not applied in the final rule.

Data from the analyses discussed above, and an additional dataset from a 1995 test program conducted by EPA’s Office of Research and Development, were used to develop inputs for MOVES, in order to model E85 impacts on air toxics inventories. Since MOBILE6 does not model air toxics for E85, ratios were developed to apply to E85 hydrocarbon or PM mass (Table 3.1-6). The exhaust ratios for all pollutants except naphthalene were obtained from data on seven vehicles from the 1995 test program in EPA’s Office of Research and Development, along with the previously discussed 2007 test program at Southwest Research Institute,[669] and the

2005 test program at Environment Canada.[670, 671] The data from the ORD test program is unpublished, but is available in the docket for this rule. Naphthalene inputs for E85 were derived from estimates from E10 values based on dilution of fuel with ethanol. The only data available on evaporative emissions were results of hot soak tests from the Auto/Oil Air Quality Improvement Research Program.[672]

**Table 3.1-6. Toxic to THC/PM Ratios used for E85 Fuel in MOVES**

| Pollutant | Exhaust/Ratio Type | Evaporative/Ratio Type |
|---|---|---|
| Benzene | 0.0036/THC | 0.0054/THC |
| 1,3-Butadiene | 0.0005/THC | N.A. |
| Acetaldehyde | 0.0673/THC | N.A. |
| Formaldehyde | 0.0093/THC | N.A. |
| Acrolein | 0.0002/THC | N.A. |
| Ethanol | 0.3316/THC | 0.6123/THC |
| Naphthalene | 0.0126/PM | 0.00006/THC |

#### 3.1.1.2.3 Spark-Ignited Off-Road Engines

Effects of E10 relative to E0 on exhaust as well as fuel tank and hose permeation emissions from gasoline-fueled off-road engines are contained in EPA's NONROAD model, based on limited data. The effects on exhaust HC, NOx, and CO are shown in Table 3.1-7. Effects on tank and hose permeation emissions vary by equipment type and were recently updated to reflect new information on uncontrolled emissions and their control due to recently finalized new standards.[673] For most small spark-ignition engines and recreational marine engines in 2022 E10 is estimated to double the tank and hose permeation emissions. There can also be increases in diurnal and refueling emissions with E10 if the fuel volatility of the blend is allowed to be greater than E0. These volatility effects are accounted for in the NMIM model that has the county-specific fuel properties that were used to generate the emission inventory impacts for this rule presented below in Section 3.2.

**Table 3.1-7.**
**Exhaust Effect of Ethanol (E10) on Spark-Ignited Gasoline Emissions**

| | 4 stroke | 2 stroke |
|---|---|---|
| HC exhaust | -15.75% | -2.1% |
| NOx | +40.25% | +65.1% |
| CO | -21.7% | -22.75% |

EPA and the California Air Resources Board (ARB) are in the midst of additional testing of off-road engines with gasoline and ethanol blends.[674, 675] and DOE completed a report in early 2009 which included small SI emission evaluation on a variety of ethanol blend fuels.[676] Although preliminary results support the type of effects listed here, there are also upcoming allowances for manufacturers to start certifying small spark ignition engines on E10 fuel rather than the current E0 gasoline sometime in the 2011-2012 timeframe.[677] If those plans proceed as expected, by 2022 most or all of the in-use small SI engines will have been certified on E10; thus we would expect none of the exhaust effects that we currently assume. Much of the in-use fleet of equipment will have turned over to new equipment certified on E10, and those that were originally certified on E0 are likely to be recalibrated. As a result, emissions are expected to result in roughly the same emissions on E10 as they currently achieve on E0. The NOx inventory increase and HC and CO decreases associated with increasing E10 market share estimated for the final rule will likely go away by 2022, since many of the E0 certified engines will have been replaced by E10 certified engines by then. However, there will still likely be effects on the mix of hydrocarbons emitted, including increased proportions of ethanol and aldehydes in the exhaust HC.

#### 3.1.1.2.4 Biodiesel Effects on Diesel Emissions

As discussed in Appendix A to this RIA, for the proposal we investigated the emission impacts on NOx, PM, HC, and CO of 20 volume percent biodiesel fuels on emissions from heavy-duty diesel vehicles.[678] Average NOx emissions were found to increase 2.2 percent, while PM, HC, and CO were found to decrease 15.6 percent, 13.8 percent, and 14.1 percent, respectively, for all test cycles run on 20 volume percent soybean-based biodiesel fuel (Table 3.1-8). These results are generally consistent with the exhaust emission impacts for heavy-duty, in-use diesel engines found in our previous work on this subject., [679] and we have retained these effects for the final rule. The effects in Table 3.1-8 are for B20, while we assume biodiesel is mostly used in concentrations of 5% or less. In applying the emission impacts to the emission inventory we assumed that the effects were proportional to biodiesel concentration based on a resent investigation into the issue, so the inventory impacts are proportional to the overall biodiesel volume used. (Cite to Chien Sze et.al. SAE Paper). For our estimate of biodiesel impacts on toxics we applied the HC emission change from Table 3.1-8 to toxic emissions.

**Table 3.1-8. B20 Emission Impacts**

| | Percent change in emissions |
|---|---|
| NOx | +2.2% |
| PM | -15.6% |
| HC | -13.8% |
| CO | -14.1% |

### 3.1.1.3 Non-GHG Emission Impact Scenarios Analyzed

For today's rule we are estimating emission impacts of three different renewable fuel volume scenarios, as presented in Chapter 1.2, which are meant to bracket the range of likely combinations of renewable fuel volumes, and these are each analyzed relative to two different reference case ethanol volumes. To assess the impact of today's rule relative to the current mandated volumes, we analyzed impacts relative to the RFS1 mandate of 7.5 billion gallons of renewable fuel use by 2012, which was estimated to include 6.7 billion gallons of ethanol. In order to assess the impact of the increased use of renewable fuels needed to meet the RFS2 standards relative to a level of ethanol projected to already be in place by 2022, the AEO2007 projection of 13.2 billion gallons of ethanol (13.6 billion gallons of total renewable fuel) in 2022 was analyzed.

### 3.1.1.4 Non-GHG Emission Impact Calculation Methodology

#### 3.1.1.4.1 On-Road Gasoline

Emissions from gasoline highway vehicles were generated with a preliminary version of EPA's final MOVES2010 model, which reflects significant updates in gasoline vehicle emissions from MOBILE6. Exhaust emission rates for HC, CO and NOx were developed based on an analysis of state inspection/maintenance and roadside remote sensing data from millions of vehicles.[680] Emissions of particulate matter are based on EPA's recent Kansas City gasoline PM study.[681,682] Evaporative emission rates have been updated based on extensive evaporative testing conducted by EPA and the Coordinating Research Council (CRC) since the release of MOBILE6, including investigations quantifying the effects of ethanol on permeation emissions.[683] For this assessment of toxics, MOVES applies toxic ratios from the MOBILE6.2 model to updated MOVES HC estimates within the model.[684]

As detailed in a memo to the docket, for the final rule, separate MOVES runs were configured for 2022 for two reference cases (RFS1 mandate and AEO) and for a control case that reflected 100 percent E10 (since we did not estimate E85 impacts for most pollutants, there was no difference between 100 percent E10 and the three volume cases - low, mid, and high ethanol - analyzed for the rule). Each of these runs required a unique "run specification" file and bundle of input databases to allow modeling of differences in analysis year and fuel supplies. Reference and control case runs in 2022 were run with estimates of fuel formulations and market shares by county as we project in 2022.

MOVES allows different levels of pre-aggregation depending on the level of resolution needed. For regional inventory applications, the finest level of aggregation the model can run is by county for each hour of the day, which maximizes the influence of inputs such as county-level fuel effects, hourly temperatures and activity patterns; however, since running the model at this level for the entire nation over multiple years and scenarios would be time prohibitive, the model was run at a higher level of aggregation to reduce run time. For the final rule inventories, new exhaust and evaporative permeation emissions were run at the national aggregation for all cases, meaning that county-level inputs were aggregated to a national average before being processed into MOVES, and hourly inputs were aggregated into an average monthly value for January and July – these monthly values were then weighted together to estimate annual emissionsWhile aggregation does lose some resolution in the overall emission results, test runs indicated that emissions differences are within a few percent of fully disaggregated runs and acceptable for estimating the emission impacts of the control programs. One key aspect of this approach is that even for higher levels of aggregation, fuel supply inputs are retained at the county level in order to maintain the resolution of fuel effects.

Because at the time of this final rule analysis the MOVES module for automating the calculation of E85 emissions from flexible fueled vehicles (FFVs) was not complete, we used estimates done for the NPRM for the E85 impact on acetaldehyde and ethanol, which were calculated by running a pre-draft version of MOVES2009 for all E85 and for all E10 and then weighting the emissions in a post-processing step. To run MOVES for "all E85" we created a special set of MOVES input files that essentially set all gasoline vehicles to run on E85. We created MOVES fuel supply and fuel adjustment tables that applied multiplicative E85 fuel adjustments from Table 3.1-6 to all gasoline vehicle emissions.[EEEEEEEE] Because sulfate and vapor venting emissions are calculated using fuel properties (sulfur level and RVP) rather than fuel adjustments, we also created a specific MOVES table of E85 fuel properties as described in Section 3.1.1.1 In a post-processing step, we calculated a weighted average of the "all E85" results and the 2022 control case, sensitivity analysis results (called "all E10" results here). We chose to use the "sensitivity" results for consistency with its premise that modern vehicles are responsive to changes in fuel characteristics. The all E85 and all E10 results were weighted together by state, model year, and vehicle type using a weighting factor that was the product of the FFV fraction and the E85 market share, where FFV fraction is the fraction of that vehicle type and model year that are projected to be E85 flexible-fueled vehicles, and the E85 marketshare is the state fraction of FFV energy use that we project will be provided by E85. These fractions were generated using the assumptions described in the sections in Chapter 1, Section 1.7.1 pertaining to Primary FFV Growth Assumptions and Projected Growth in E85 Access. We performed this calculation for passenger cars and trucks and light commercial trucks only since the number of heavy-duty vehicles using E85 is expected to be small.

Toxic emissions were still in development for MOVES at the time of this analysis; for this analysis some post-processing was required to generate complete inventory estimates. Specific toxic:hydrocarbon ratios by fuel formulation, vehicle class and model year were developed from a series of MOBILE6 runs and fed into MOVES, which applied these ratios to HC emissions to produce emissions of benzene, acetaldehyde, 1-3 butadiene, formaldehyde and acrolein for all of these cases analyzed. Naphthalene from heavy-duty vehicles was ratioed to PM 10 in MOVES. For light-duty vehicles, naphthalene emissions were calculated as the sum of PM 2.5 elemental carbon and PM 2.5 organic carbon emissions times a ratio of 0.088. Aggregate ratios from the running emissions were also applied to start emissions to develop overall toxic emission inventories. E85 emissions were calculated in MOVES using the factors in Table 3-1.6.

#### 3.1.1.4.2 Off-Road Gasoline

Emissions from nonroad gasoline equipment were developed by running the National Mobile Inventory Model (NMIM), a consolidated emissions modeling system for EPA’s MOBILE6 and NONROAD models.[685] The key feature of NMIM is a national county database (NCD), which includes county-level information on temperatures, fuel properties, equipment populations, etc. NMIM runs MOBILE6 and NONROAD based on information in the NCD. The NCD used to produce these inventories was updated as part of the 2005 National Emission

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[EEEEEEEE] The MOVES fuel adjustment table developed for this analysis contained all E85 fuel effects from Table 3.1-9, including the not statistically significant NOx and NMHC results; however, only results pollutants identified as statistically significant in Table 3.1-9 are reported in the sensitivity case inventory results

Inventory (NEI) process.[686] The NCD also included the 2005 and 2022 fuels described in Section 3.1.1.2. The version of the NONROAD Model used included the effects of the 2008 Final Rule: Control of Emissions of Air Pollution from New Nonroad Spark-Ignition Engines, Equipment, and Vessels.[687] It is also capable of modeling the effects of gasoline blends containing 10 percent or less of ethanol.

Emissions from onroad and nonroad diesel equipment were also developed by running NMIM (see above), using the same NCD and version of the NONROAD Model described above. The version of MOBILE was MOBILE6.2. Diesel fuels are less fully characterized than gasoline, since the only property used by MOBILE and NONROAD is fuel sulfur.

Most toxic emissions for off-road equipment were taken directly from NMIM. The one exception was ethanol, which is not estimated by NMIM, so ethanol emissions were based on VOC speciation from light-duty gasoline vehicles. Ethanol inventories for the control case were developed by applying ratios of the aggregate MOVES ethanol exhaust, evaporative and refueling emissions for on-road gasoline for control versus reference cases, to the reference case ethanol emissions for off-road equipment.

#### 3.1.1.4.3 On-Road Diesel

As it is likely that biodiesel will be consumed in a variety of blend levels (e.g. 20 percent, 5 percent, 2 percent) by light-duty diesel vehicles and off-road diesel equipment as well as heavy-duty diesel vehicles, we assumed for this analysis that the effects of biodiesel on emissions are linear with biodiesel concentration as demonstrated by Sze, et al,[688] and that impacts can be analyzed assuming all biodiesel is blended as B20. We applied the B20 effects discussed in Section 3.1.1.2.4 to baseline heavy-duty emissions generated by NMIM, as MOVES heavy-duty diesel estimates were not available in time for this analysis. Biodiesel impacts were using the following formula:

$$\text{Biodiesel Impact}_{P} = \text{Base HD Emissions}_{P} * \text{Effect}_{P} * (\text{Increase in B20 Volume / Total Diesel Volume})$$

*Where:*

*P = pollutant*
*Effect = Percent change with B20 blend from Section 3.1.1.3.3*
*Increase in B20 Volume= Change in B20 volume from 2022 reference case to control case*
  *in billion gallons of B20 blend (ie, change in gallons of biodiesel * 5)*
*Total Volume = Total Highway Diesel Volume in 2022 in billion gallons*

Toxic effects were calculated using the HC effects from Table 3.1-8.

It should be noted that the emission inventory impacts estimated for biodiesel used baseline diesel emissions from NMIM (using MOBILE6), which are significantly lower than the updated estimates in MOVES2010. Using MOVES, the increase in NOx and decrease in PM from the projected biodiesel volumes may be twice the magnitude of those reported in this rule.

#### 3.1.1.4.4 Portable Fuel Containers

There are several sources of emissions associated with portable fuel containers (PFC) used for gasoline. These sources include vapor displacement and spillage while refueling the gas can at the pump, spillage during transport, permeation and evaporation from the gas can during transport and storage, and vapor displacement and spillage while refueling equipment. As the calculation of emissions for refueling non-road equipment includes spillage and some vapor displacement, these impacts are not included here. For the final rule we did not update these estimates from the proposal.

As part of the 2007 regulation controlling emissions of hazardous pollutants from mobile sources (MSAT2 rule), EPA promulgated requirements to control VOC emissions from gas cans. The methodology used to develop emission inventories for gas cans is described in the regulatory impact analysis for the rule and in an accompanying technical support document.[689, 690]

Based on the MSAT work, we generated two sets of hypothetical nationwide annual estimates of PFC VOC emissions, for calendar years 2017 and 2030, based on all E0 and all E10. Interpolation can be used to estimate PFC VOC emissions for the reference cases. Proportions of national E0 and E10 fuel use were calculated for the 2022 reference and control cases. The reference case featured a mix of 89.1% E10 and 10.9% E0, while the policy case featured 100% E10. While E85 is used in flexible fueled highway vehicles, it is unlikely to be used in the near future in non-road equipment, and is therefore unlikely to be stored or dispensed from PFCs.

MSATs found in liquid gasoline will be present as a component of VOC emissions. These MSATs include benzene and naphthalene. Ethanol is present as well in VOC emissions from ethanol blends. Inventories for these pollutants were estimated by the application of toxic to VOC ratios.

For benzene emissions from all sources except permeation, the following formula was used to calculate toxic to VOC ratios:

$$\begin{gathered} PFC\ Benzene\ Emissions = \\ PFC\ VOC\ Emissions \times \left( \frac{\mathrm{Re}\,fueling\ Benzene_{LDGV}}{\mathrm{Re}\,fueling\ VOC_{LDGV}} \right) \times 0.36 \end{gathered}$$

where the ratio of refueling benzene to VOC was estimated using average nationwide fuel properties for zero and 10 percent ethanol gasoline from refinery modeling, done for RFS rule, and applied to EPA's Complex Model for reformulated gasoline.[691, 692] The 0.36 multiplier corrects for the difference in the percentage of gasoline in refueling emissions at 90º F, the temperature assumed for the algorithm in the Complex Model, versus a more typical lower fuel temperature of 60 º F for gas cans. The basis of this adjustment is discussed in more detail in the regulatory impact analysis for the Mobile Source Air Toxics Rule. An additional adjustment factor is applied to the ratio for permeation emissions, based on a recent study[693] that suggests that the ratio of benzene from permeation to total VOC from permeation is about 1.77 times higher than the ratio associated with evaporation, according to the following formula:

$$PFC\ Benzene\ Emissions =$$

$$PFC\ VOC\ Emissions \times \left( \frac{\mathrm{Re}\ fueling\ Benzene_{LDGV}}{\mathrm{Re}\ fueling\ VOC_{LDGV}} \right) \times 0.36\ x\ 1.77$$

The resulting ratios for 0% and 10% ethanol did not differ at the fifth decimal place, and were 0.0135 for all sources except for permeation, and 0.00239 for permeation. Thus, impacts of this rule on benzene emissions are due to the overall impact of RVP changes on total VOC emissions.

A naphthalene to VOC ratio was estimated using the following formula:

$$PFC\ Naphthalene\ Emissions =$$

$$PFC\ VOC\ Emissions \times \left( \frac{Evaporative\ Naphthalene_{LDGV}}{Evaporative\ VOC_{LDGV}} \right) \times 0.0054$$

An evaporative naphthalene to VOC ratio for light-duty gasoline vehicles of 0.0004 was obtained from analyses done for the Mobile Source Air Toxics Rule, and did not vary by fuel type. The 0.0054 adjustment was based on a recent analysis of average nationwide percentage of naphthalene in gasoline vapor from gasoline distribution with an RVP of 10 psi at 60 degrees Fahrenheit.[694, 695] The resulting ratio applied to PFC emissions was 0.0000022.

For E10 fuel, we assumed 16.74 percent of the evaporative emissions were ethanol (SPECIATE profile 1301)[696] and 33.34 percent of permeation emissions were ethanol.[697]

#### 3.1.1.4.5 Refueling Emissions

Refueling emissions were calculated by NMIM, based on MOBILE6 refueling module. Emissions are impacted by the increase in RVP due to ethanol, and also because the reduced energy density of ethanol would require more fillups. NMIM directly provides the emission increase due to increased RVP for the areas allowing the 1.0 psi waiver, so no additional processing was required to estimate RVP effects on refueling. For the final rule we did not update these estimates from the proposal, except to account for the different control cases.

In order to estimate the emission impact of the increase in refueling events, we developed ton per gallon refueling emission factors based on NMIM by dividing total refueling emissions from NMIM for each case by the number of gallons consumed in the AEO case. The ton per gallon emission factors were then applied to the total volume in gallons in each case. Fuel volumes for the RFS 1 mandate and AE0 reference cases compared to the NPRM and final rule control cases are listed in Table 3.1-9. Our estimates of total gallons were calculated from energy balance, reflecting the various numbers of gallons needed to consume the same energy. We assume the number of trips to the pump will increase in proportion to the increased gallons estimated for the rule.

**Table 3.1-9. Gasoline Volumes (Billion Gallons)**

| | RFS 1 Mandate | AEO 2007 | NPRM Control Case | RFS1 Mandate 2022 | AEO 2008 rev 2022 | FRM RFS2 Control Low EtOH | FRM RFS2 Control Primary | FRM RFS2 Control High EtOH |
|---|---|---|---|---|---|---|---|---|
| E0 | 107.51 | 16.03 | 0 | 65.72 | 6.46 | 0.00 | 0.00 | 0.00 |
| E10 | 36.40 | 131.00 | 124.6 | 70.46 | 131.82 | 134.25 | 128.79 | 115.82 |
| E85 | 0.00 | 0.11 | 29.3 | 0.00 | 0.00 | 5.49 | 12.54 | 29.26 |
| **Total Gallons** | **143.91** | **147.14** | **153.9** | **136.18** | **138.28** | **139.74** | **141.32** | **145.08** |

### 3.1.2 Impact on Non- GHG Emissions from Fuel Production and Distribution

In addition to the effects of increased renewable fuel use on emissions from the vehicles and equipment that use the fuels, as discussed above, there are shifts in the fuel production and transport/distribution methods that can have substantial impacts on emissions. These "upstream" emissions are associated with all stages of biofuel production and distribution, including biomass production (agriculture, forestry), fertilizer and pesticide production and transport, biomass transport, biomass refining (corn or cellulosic ethanol production facilities), biofuel transport to blending/distribution terminals, and distribution of finished fuels to retail outlets. Additionally, changes in agricultural economics associated with increased biomass production can result in shifts in related agricultural production, such as livestock.

This section describes the changes in upstream emission sources and related emission rates connected with the renewable fuel use. The emission inventory impacts resulting from these changes are described in Section 3.2. This section is divided into two major sub-sections, the first covering emissions of criteria pollutants, their precursors, and ammonia, and the second covering non-criteria air toxic emissions and ethanol. The specific air toxics covered are: benzene, acetaldehyde, formaldehyde, 1,3-butadiene, acrolein, and naphthalene.

### 3.1.2.1 Upstream Criteria Pollutants

#### 3.1.2.1.1 Agricultural Sector

*Introduction*

In prior EPA estimates, such as the RFS1 rule, changes in agricultural emissions were based solely on the increases in bushels of corn (and soybeans for biodiesel), and the necessary acreage to produce those additional bushels. Given the greater pressure on farmland use likely in the 2022 timeframe for today’s rule (15 billion gallons of corn ethanol plus up to 16 billion gallons of cellulosic ethanol) compared to the 2012 assessment for RFS1 (6.7 or 9.6 billion gallons of ethanol depending on scenario), additional factors have been added to the agricultural analysis, such as likely shifts of acreage to corn from certain other crops as corn prices increase.

The number of acres of cropland for corn, soy, and all other principle crops were estimated using the FASOM agriculture and forestry model, as described in Section 5.1 of this document. We are using the change in total acres of planted cropland to estimate changes in certain agricultural emissions, such as tillage dust, that are not directly calculated by FASOM. Another substantial source of agricultural emissions (especially ammonia and methane) is livestock. Changes in livestock-related emissions are estimated based on the change in head counts of cattle, swine, and poultry predicted by FASOM.

The impacts relative to the RFS1 mandate reference case (6.7 billion gallons of ethanol) rely only on applying ethanol volume proportions to the modeling results of the AEO reference case (13.2 billion gallons). Due to the complex interactions involved in projections in the agricultural modeling, we did not attempt to adjust the agricultural inputs of the AEO reference case for the RFS1 reference case. So the fertilizer and pesticide quantities, livestock counts, and total agricultural acres were the same for both reference cases. The agricultural modeling that had been done for the RFS1 rule itself was much simpler and inconsistent with the new modeling, so it would be inappropriate to use those estimates. We had planned to conduct additional agricultural modeling specifically for the RFS1 mandate case prior to finalizing this rule, but there was not sufficient time and resources to accomplish that after all the other updates and sensitivities analyzed for the AEO case alone for the final rule.

###### 3.1.2.1.1.1 VOC/NOx/CO/SOx/PM2.5

Criteria pollutants related to agricultural operations come from five major sources: farm equipment (mainly diesel engine emissions), fertilizer production and application, pesticide production and application, burning of crop residue, and fugitive dust from field tilling and related activities.

*Agricultural Equipment Emissions*

Changes in farm equipment emissions were estimated by multiplying an average fuel-based emission factor for diesel or gasoline farm equipment by the change in farm fuel consumption predicted by FASOM. The emission factors for each pollutant in units of grams emitted per million BTU of fuel burned were calculated from EPA NONROAD2005 nationwide modeling outputs for 2022 (pollutant tons emitted, gallons of fuel consumed) for each year of interest. The diesel emissions include all agricultural diesel equipment, which are dominated by agricultural tractors, while the gasoline emissions include only the limited number of larger agricultural gasoline-fueled equipment, such as tractors, combines, balers, swathers, and irrigation sets. The fuel energy contents (lower heating value) used for the unit conversions were 115,000 BTU/gallon for gasoline and 130,000 BTU/gallon for diesel. For comparison, the corresponding 2020 emission factors from GREET are shown, where available. Most of the differences between NONROAD and GREET are small and are likely attributable to the difference between 2020 and 2022 values. And although the gasoline equipment emission factors for VOC and CO from NONROAD are much greater than those used in GREET, this does not have much impact on emission inventories due to the small number of gasoline-fueled equipment used in agriculture relative to diesel equipment.

### Table 3.1-10.
### Agricultural Equipment Emission Factors
### (grams per mmBTU of fuel burned)

| Pollutant | Diesel | | Gasoline | |
|---|---|---|---|---|
| | NONROAD | GREET | NONROAD | GREET |
| NOx | 306 | 298 | 204 | 208 |
| VOC | 30.55 | 34.87 | 355.53 | 52.30 |
| PM10 | 21.12 | 22.67 | 7.49 | 9.07 |
| PM2.5 | 20.49 | 20.41 | 6.89 | 8.34 |
| CO | 130 | 136 | 10,067 | 204 |
| Benzene | 0.62 | -- | 11.90 | -- |
| Ethanol | 0.00 | -- | 0.00 | -- |
| 1,3-Butadiene | 0.057 | -- | 1.90 | -- |
| Acetaldehyde | 1.62 | -- | 1.63 | -- |
| Formaldehyde | 3.61 | -- | 3.17 | -- |
| Naphthalene | 0.027 | -- | 0.66 | -- |
| Acrolein | 0.09 | -- | 0.14 | -- |
| SO2 | 0.44 | -- | 15.88 | -- |
| NH3 | 0.68 | -- | 1.01 | -- |

*Fertilizer and Pesticide Production*

The manufacturing processes for agricultural fertilizer and pesticides generate a variety of air pollutants. The agricultural inputs from GREET provide emission factors in grams of pollutant per ton of nutrient for various types of fertilizers, herbicides, and insecticide, as shown in Table 3.1-12. These air emission factors were multiplied by the changes in fertilizer and pesticide use predicted by FASOM, as shown in Table 3.1-11, to give projected changes in nationwide agricultural fertilizer and pesticide production emissions.

### Table 3.1-11.
### Changes in Agricultural Chemical Use for 2022 RFS2 Control Case Relative to AEO2007 Reference Case

| | **Nitrogen** (average) | **Phosphate** (P2O5) | **Potash** (K2O) | **Limestone** (CaCO3) | **Herbicides** | **Pesticides** |
|---|---|---|---|---|---|---|
| Annual Short Tons | 750,629 | 357,069 | 662,157 | 260,304 | -750 | -381 |
| Percentage | 5.73% | 12.72% | 20.16% | 2.55% | -0.38% | -0.86% |

### Table 3.1-12.
### Agricultural Chemical Production & Transport Air Emission Factors
### (grams per ton of nutrient)

| Pollutant | **Nitrogen** (average) | **Phosphate** (P2O5) | **Potash** (K2O) | **Limestone** (CaCO3) | **Herbicides** | **Pesticides** |
|---|---:|---:|---:|---:|---:|---:|
| NOX | 1,605 | 4,484 | 734 | 573 | 19,371 | 21,628 |
| VOC | 2,761 | 240 | 40.7 | 56.8 | 1,575 | 2,040 |
| PM10 | 454 | 1,551 | 148 | 506 | 10,840 | 11,746 |
| PM2.5 | 262 | 1,018 | 74.5 | 167 | 4,869 | 5,479 |
| CO | 2,595 | 790 | 129 | 186 | 5,417 | 6,872 |
| Benzene | 0.00 | 0.00 | 0.00 | 0.00 | 3.21 | 4.16 |
| Ethanol | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| 1,3-Butadiene | 0.000 | 0.000 | 0.000 | 0.000 | 0.576 | 0.745 |
| Acetaldehyde | 0.018 | 0.001 | 0.000 | 0.000 | 0.082 | 0.106 |
| Formaldehyde | 20.75 | 1.55 | 0.19 | 0.41 | 18.11 | 23.44 |
| Naphthalene | 0.033 | 0.117 | 0.010 | 0.039 | 114.4 | 124.0 |
| Acrolein | 0.009 | 0.001 | 0.000 | 0.000 | 0.024 | 0.031 |
| SO2 | 703 | 53,299 | 321 | 701 | 11,300 | 12,895 |
| NH3 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |

Until the 1990s it was reasonable to assume that all fertilizers and pesticides used on domestic agriculture were produced within the U.S. This has been less true in recent years as more agricultural chemicals, especially fertilizers, are being imported from countries with a greater availability of natural gas at lower costs. For greenhouse gases the location of these emissions is of less importance, but for criteria pollutants and toxics it is important to reduce the estimated impacts by the percentage of production and transportation occurring outside of the U.S. Using data from USDA[698,699] the percentages applied from domestic sources are shown in Table 3.1-13. After applying these percentages to the production and initial transportation portions of the GREET emission factors, the unadjusted final (domestic) transportation portion of the GREET emission factors was added back in. Since the relative emissions from production versus transportation vary by pollutant, the net adjustments to the GREET emission factors also vary by pollutant, as shown in the second Section of Table 3.1-13. To calculate an overall factor for nitrogen fertilizers, the proportions from GREET were used: 70.7% ammonia, 21.1% urea, and 8.2% ammonium nitrate. The pesticide adjustment does not vary by pollutant because virtually all of the pesticide emissions come from actual production rather than transportation/distribution.

**Table 3.1-13.**
**Domestic Fractions of Fertilizer and Pesticide Production Applied to Crops**

| | Nitrogen Fertilizers | Potash | Phosphate | Pesticides |
|---|---|---|---|---|
| Domestic Fraction of Production | 50% | 20% | 94% | 76% |
| | | | | |
| Net Adjustment to Production, Transportation & Distribution Emission Factor from GREET | | | | |
| VOC | 50.63% | 94.85% | 53.62% | 76% |
| CO | 52.47% | 94.92% | 54.37% | 76% |
| NOx | 73.34% | 94.92% | 65.55% | 76% |
| PM10 | 52.64% | 94.12% | 24.06% | 76% |
| PM2.5 | 53.67% | 94.14% | 28.31% | 76% |
| SOx | 60.48% | 94.02% | 33.66% | 76% |

*Fertilizer and Pesticide Application*

In addition to the agricultural equipment emissions mentioned above, the application of fertilizer and pesticides (herbicides, insecticides, fungicides, etc.) to agricultural fields causes the release of certain types of pollutants into the air. For nitrogen fertilizers the only pollutant considered to be significant is ammonia (NH3), the estimation of which is covered in Section 3.1.3.1.1.2. Pesticide application emissions are mainly VOC and various individual organic compounds, most notably benzene and acrolein. A discussion of the toxic pollutant emissions as a fraction of VOC is presented in Section 3.1.3.2.2, but the resulting emission factors and inventory impacts are shown here in Table 3.1-14. There are also potential toxicity concerns with volatilization of the pesticide active ingredients, and this is discussed in Section 3.4 of this document.

The basis of the pesticide application emissions for this analysis was the 2002 NEI area-source inventory. The ton per year emissions data from the NEI was used with USDA pesticide application data for 2002 (or the nearest year for which data were collected) to generate an overall average estimate of the pesticide application emissions per ton of pesticide applied. This ratio of pollutant tons (for VOC, benzene, and acrolein) per ton of pesticide applied was then multiplied by the change in total pesticide tons used (including herbicides) as projected by FASOM and shown in Table 3.1-11 to give the projected change in nationwide agricultural pesticide application emissions in Table 3.1-14.

### Table 3.1-14.
### Herbicide and Pesticide Application Air Emission Factors and Impacts for 2022 RFS2 Control Case Relative to AEO2007 Reference Case

| Pollutant | Emission Factor | Air Emission Impact |
|---|---|---|
| | (tons per ton applied) | (annual short tons) |
| VOC | 0.543 | -614 |
| Benzene | 0.142 | -161 |
| Acrolein | 0.0036 | -4.06 |

*Agricultural Residue Burning Emissions*

One source of air pollution related to crop farming is the burning of crop residues. This practice is one of the methods that is used to clear fields between crop cycles so that the old crop residue does not build up and clog or otherwise hinder the tilling of the fields in preparation for new crop planting. This practice is mainly used for grassy crops like wheat, rye, and barley, but in some areas it is also used for corn and other crops.

Crop residue burning produces substantial emissions of CO2, VOC, CO, NOx, as well as ammonia and toxic pollutants such as benzene, formaldehyde, 1,3-butadiene, and acrolein.

The use of crop residue burning is quite variable from area to area and among individual farmers, since there are alternative methods to deal with crop residue, including use of conservation tillage methods and equipment that allows planting through the residue. In some locations and time periods crop residue burning has been prohibited by law, due to the possible health effects in nearby residential areas. Another aspect of uncertainty in estimating crop burning emissions is that the NEI does not currently cover all states where crop residue burning occurs. Despite these data limitations, the NPRM used the available data to generate a rough overall estimate of the average crop burning emissions per acre of planted crops, and then multiplied that emission rate to the change in total crop acres predicted by FASOM to generate an estimated emission inventory impact.

For this final rule analysis we have reconsidered the inclusion of any crop residue burning impact and decided not to include it. This reconsideration was driven by the facts that (a) the crops most likely to be impacted by this rule do not tend to be ones for which residue burning is used, and (b) even for those crops affected by this rule that might otherwise have their residue burned, for this analysis they would much more likely have that residue harvested and used as cellulosic feedstock in a biofuel plant. Given the uncertainty in projecting these emission impacts, we did not want any rough assumptions made to unduly influence the emission impact assessment.

*Agricultural Dust Emissions*

Soil and related dust particles (e.g., fertilizer, pesticide, manure) become airborne as a result of field tillage and animal grazing/foraging, especially in drier areas of the country. Some of this dust is in a size range that is a concern for human health and welfare. The NEI includes estimates of these particulate emissions by county.

The agricultural dust data from the 2002 NEI was used to generate an estimate of the average fugitive dust emissions per acre of planted crops for the crop related dust, and per head of cattle for the dust related to cattle. This was done using 2002 nationwide crop acreage and livestock inventory data from USDA/NASS. The calculated pollutant mass (tons of PM) per total acre farmed was then multiplied by the change in total planted acres projected by FASOM to give a projected change in nationwide crop related dust emissions. And the calculated PM tons per head of cattle was multiplied by the change in cattle inventory projected by FASOM to give a projected change in nationwide livestock related dust emissions.

The emission factors and inventory impacts of fugitive dust from crop related activities and livestock are shown in Table 3.1-15 and 3.1-16. The ton per year impacts for the crop-related emissions are based on a modeled increase of 8.1 million farmed acres (2.65 percent) in 2022 relative to the AEO2007 reference case. The changes in fugitive dust from livestock operations are based on the head count changes shown in Table 3.1-18.

**Table 3.1-15.**
**2022 Crop-related Dust Emission Impacts for the 2022 RFS2 Control Case Relative to AEO2007 Reference Case**

| **Pollutant** | **Emission Factors** | **Inventory Impacts** |
|---|---|---|
| | (Tons per thousand acres farmed) | (annual short tons) |
| PM10 | 6.807 | 55,182 |
| PM2.5 | 1.021 | 8,277 |

**Table 3.1-16.**
**2022 Livestock-related Dust Emission Impacts for the 2022 RFS2 Control Case Relative to the AEO2007 Reference Case**

| **Pollutant** | **Beef Cattle Dust Emissions** | | **Dairy Cattle Dust Emissions** | |
|---|---|---|---|---|
| | (kg/head/year) | (annual short tons) | (kg/head/year) | (annual short tons) |
| PM10 | 0.888 | -139.68 | 0.172 | -8.34 |
| PM2.5 | 0.089 | -14.00 | 0.017 | -0.82 |

#### 3.1.2.1.1.2 Ammonia (NH3)

The two primary sources of ammonia emissions into the air on farms are fertilizer application and livestock waste. Fertilizer application emissions were estimated using an average emission factor of 57,428.71 grams per ton of fertilizer nitrogen applied for all forms of nitrogen, which is a weighted average of the standard EPA emission factors that are used to generate the NEI. The weightings for each type of fertilizer come from USDA Economic Research Service data for 2006. The individual emission factors, weightings, and resulting average emission factor are shown in Table 3.1-17. This average emission factor was multiplied by the nitrogen application quantities generated by the FASOM model for each scenario.

**Table 3.1-17. Fertilizer Ammonia Emission Factors**

| Fertilizer Type | SCC | Emission Factor (lbs NH3/Ton Nitrogen) | USDA 2006 all crops Weighting |
|---|---|---|---|
| Anhydrous Ammonia | 2801700001 | 24 | 15.46% |
| Aqua Ammonia | 2801700002 | 24 | 1.61% |
| Nitrogen Solutions | 2801700003 | 61 | 40.88% |
| Urea | 2801700004 | 364 | 21.73% |
| Ammonium Nitrate | 2801700005 | 49 | 3.9% |
| Ammonium Sulfate | 2801700006 | 194 | 4.93% |
| Ammonium Thiosulfate | 2801700007 | 64 | |
| Other Straight Nitrogen | 2801700008 | 61 | 11.49% |
| Ammonium Phosphates | 2801700009 | 97 | |
| N-P-K | 2801700010 | 97 | |
| | | | |
| **avg lbs/ton** | | | **126.61** |
| **avg grams/ton** | | | **57428.71** |

Changes in ammonia emissions from livestock waste were estimated using emission factors (kg/head/year) multiplied by the change in animal head counts predicted by FASOM. The ammonia emission factors and livestock head changes used in this analysis, along with resulting ammonia inventory impacts are shown in Table 3.1-18. This analysis was limited to these four types of livestock because they are the ones specifically modeled by FASOM.

**Table 3.1-18. Livestock Ammonia Emission Impacts for 2022 RFS2 Control Case Relative to the AEO2007 Reference Case**

| Livestock Type | kg NH3 per head per year[a] | Head count change (million head) | Percent change | Change in NH3 emissions (annual short tons) |
|---|---|---|---|---|
| Beef Cattle | 9 | -0.143 | -0.23% | -1,416 |
| Dairy Cattle | 25 | -0.044 | -0.65% | -1,212 |
| Swine | 5 | 3.95 | 3.24% | 21,711 |
| Poultry | 0.22 | -73.5 | -0.98% | -17,798 |

[a] Source: EPA/600/R-02-017, "Review of Emission Factors and Methodologies to Estimate Ammonia Emissions From Animal Waste Handling," April 2002.

Although it is a minor source of ammonia compared to fertilizer and livestock emissions described above, changes in farm equipment ammonia emissions were estimated by multiplying an average fuel-based emission factor for diesel or gasoline farm equipment by the change in farm fuel consumption predicted by FASOM. The ammonia emission factors in units of grams emitted per million BTU of fuel burned were calculated from the default ammonia emission factors used in the EPA NMIM model: 116 mg per gallon of gasoline burned; and 88.3 mg per gallon of diesel fuel burned.

#### 3.1.2.1.2 Biofuel Production

Emissions from the production of biofuels include the emissions from the production facility itself as well as the emissions from production and transport of the biomass and any other fuels used by the biofuel plant, such as natural gas, coal, and electricity. The biomass feedstock production emissions are discussed above in the section on agricultural emissions. The calculation of emissions from corn ethanol, cellulosic ethanol, and biodiesel plants, including feedstock transport, was done using the basic methodology of the GREET model. But some updates and enhancements were made to GREET, including updated feedstock energy requirements and estimates of excess electricity available for sale from new cellulosic ethanol plants, based on modeling by the National Renewable Energy Laboratory (NREL). Since certain biofuel production processes generate co-products that could also be used in the gasoline market, we have accounted for those by decreasing the refined gasoline volume on an equal fuel energy basis to the co-products. This was done in two cases -- co-product naphtha from the Fischer-Tropsch process and C3+ alcohols from the thermochemical ethanol from mixed alcohols process.

The facility emission factors used are shown in Table 3.1-19. These have been updated for this final rule based on new analyses of projected plant efficiency improvements, rather than using older analyses, such as dry mill corn plant emission data from plants existing in 2005 as was used for the NPRM and air quality modeling inventories. These new analyses, discussed in Section 1.5.1.3 for corn ethanol, Section 1.5.3 for cellulosic ethanol and diesel, and Section 1.5.4 for biodiesel, provide projections of energy and feedstock requirements for biofuel production. These energy requirements are then multiplied by emission factors (grams per mmBTU of feedstock consumed) from the GREET model to yield the gram per gallon emission factors presented here.

**Table 3.1-19.**
**Biofuel Production Plant Emission Factors in 2022**
**(grams per gallon produced)**

| Biofuel Plant Type | VOC | CO | NOx | PM10 | PM2.5 | SOx | NH3 |
|---|---|---|---|---|---|---|---|
| Corn Ethanol, Dry Mill NG | 2.29 | 0.58 | 0.94 | 0.94 | 0.23 | 0.01 | 0.00 |
| Corn Ethanol, Dry Mill NG (wet DGS) | 2.27 | 0.37 | 0.60 | 0.91 | 0.20 | 0.00 | 0.00 |
| Corn Ethanol, Dry Mill Biogas | 2.29 | 0.62 | 1.00 | 0.94 | 0.23 | 0.01 | 0.00 |
| Corn Ethanol, Dry Mill Biogas (wet DGS) | 2.27 | 0.39 | 0.63 | 0.91 | 0.20 | 0.00 | 0.00 |
| Corn Ethanol, Dry Mill Coal | 2.31 | 2.65 | 3.68 | 3.64 | 1.54 | 3.48 | 0.00 |
| Corn Ethanol, Dry Mill Coal (wet DGS) | 2.28 | 1.68 | 2.34 | 2.62 | 1.03 | 2.21 | 0.00 |
| Corn Ethanol, Dry Mill Biomass | 2.42 | 2.55 | 3.65 | 1.28 | 0.36 | 0.14 | 0.00 |
| Corn Ethanol, Dry Mill Biomass (wet DGS) | 2.35 | 1.62 | 2.32 | 1.12 | 0.28 | 0.09 | 0.00 |
| Corn Ethanol, Wet Mill NG | 2.33 | 1.04 | 1.68 | 1.00 | 0.29 | 0.01 | 0.00 |
| Corn Ethanol, Wet Mill Coal | 2.33 | 3.50 | 4.86 | 4.53 | 1.98 | 4.60 | 0.00 |
| Cellulosic Ethanol (Enzymatic, switchgrass or corn stover) | 1.45 | 4.68 | 6.71 | 1.63 | 0.53 | 0.25 | 0.00 |
| Cellulosic Ethanol (Enzymatic, forest waste) | 1.46 | 4.93 | 7.06 | 1.67 | 0.55 | 0.26 | 0.00 |
| Cellulosic Ethanol (Thermochemical, switchgrass or corn stover) | 0.49 | 6.99 | 10.03 | 1.16 | 0.58 | 0.37 | 0.00 |
| Cellulosic Ethanol (Thermochemical, forest waste) | 0.49 | 6.99 | 10.03 | 1.16 | 0.58 | 0.37 | 0.00 |
| Biodiesel, Soybean oil | 0.04 | 0.43 | 0.69 | 0.06 | 0.06 | 0.01 | 0.00 |
| Biodiesel, Yellow grease/tallow | 0.04 | 0.50 | 0.80 | 0.07 | 0.07 | 0.01 | 0.00 |
| Biodiesel, Fuel grade corn oil | 0.04 | 0.50 | 0.80 | 0.07 | 0.07 | 0.01 | 0.00 |
| Biodiesel, Algae | 0.01 | 0.10 | 0.16 | 0.01 | 0.01 | 0.00 | 0.00 |
| Renewable Diesel*, Yellow grease | 0.00042 | 0.00475 | 0.00767 | 0.00065 | 0.00065 | 0.00006 | 0.00 |
| Cellulosic Diesel (Thermochemical, Fischer-Tropsch forest waste) | 0.91 | 13.39 | 20.22 | 2.39 | 1.20 | 1.80 | 0.00 |

* The renewable diesel emission factors are based only on the energy needed for hydrotreating at an existing refinery, which is different from stand-alone facilities we project in Section 1 will be making renewable diesel (RD). An RD plant would have more feedstock handling, pumping, etc., as well as general plant energy overhead than for a marginal unit in a refinery.

### 3.1.2.1.3 Crude Oil Production/Transport/Refining

The estimate of emissions associated with production of gasoline and diesel fuel from crude oil is based on emission factors in the GREET model. The actual calculation of the emission inventory impacts of the decreased gasoline and diesel production is done in EPA's spreadsheet model for upstream emission impacts.[700] This model uses the decreased volumes of the crude based fuels and the various crude production and transport emission factors from GREET to estimate the net emissions impact, which is shown below in Section 3.2 (see the displaced gasoline row of Table 3.2-5).

### 3.1.2.1.4 Finished Fuel Transport and Distribution

*Transfer and Storage Evaporative Emissions from Gasoline, Gasoline/Ethanol Blends, and Ethanol* -- VOC emissions are produced by transfer and storage activities associated with distribution of gasoline, gasoline/ethanol blends, and ethanol. These are referred to as Stage I emissions.[701] Stage I distribution begins at the point the fuel leaves the production facility and ends when it is loaded into the storage tanks at dispensing facilities.

There are five types of facilities that make up this distribution chain for gasoline. Bulk gasoline terminals are large storage facilities that receive gasoline directly from the refineries via pipelines, barges, or tankers (or are collocated at refineries). Gasoline from the bulk terminal storage tanks is loaded into cargo tanks (tank trucks or railcars) for distribution to smaller intermediate storage facilities (bulk plants), or directly to gasoline dispensing facilities (retail public service stations and private service stations). When ethanol is blended into gasoline it usually occurs in the pipes which supply the tank trucks.

There are two types of pipeline facilities found at various intervals along gasoline distribution pipelines: pipeline breakout stations and pipeline pumping stations. Pipeline breakout stations receive gasoline via pipelines, store it in storage tanks, and re-inject it into pipelines as needed to meet the demand from downstream facilities. Pipeline pumping stations are located along the entire length of a pipeline at about 40 mile intervals. Their purpose is to provide the extra ‘‘push’’ needed to move the product through the pipeline. They do not normally have gasoline storage capability.

Bulk plants are intermediate storage and distribution facilities that normally receive gasoline or gasoline/ethanol blends from bulk terminals via tank trucks or railcars. Gasoline and gasoline/ethanol blends from bulk plants are subsequently loaded into tank trucks for transport to local dispensing facilities.

Gasoline and gasoline/ethanol blend dispensing facilities include both retail public outlets and private dispensing operations such as rental car agencies, fleet vehicle refueling centers, and various government motor pool facilities. Dispensing facilities receive gasoline and gasoline/ethanol blends via tank trucks from bulk terminals or bulk plants. Inventory estimates for this source category only include the delivery of gasoline at dispensing facilities and does not include the vehicle or equipment refueling activities.

Emission factors (EFs) for gasoline were based on inventory estimates from the 2002 NEI.[702] We used these data to develop E0 gasoline emission factors even though the 2002 emissions included the E10 that was in the fuel pool at that time. In 2002 this was still a relatively small proportion of gasoline consumption, so it should not substantially affect the national E0 estimates. Since ethanol is blended with gasoline at bulk terminals to produce E10 and E85 at the point fuel is loaded into tank trucks, we assumed bulk terminal emissions were associated with unblended gasoline. We then divided emissions into a refinery to bulk terminal component and a bulk terminal to dispensing facility component. Total nationwide emissions for these two components were divided by the energy content of the total volume of gasoline distributed in 1999, to obtain the emission factor in g/mmBTU. Total volume of gasoline was based on gasoline sales as reported by the Energy Information Administration.[703] These emission factors are provided in Table 3.1-20.

We also developed emission factors for Stage 1 emissions of E10 and E85 subsequent to blending at bulk terminals. These emission factors were calculated by applying adjustment factors to the gasoline EF. The adjustment factors for E10 and E85 were based on an algorithm from the 1994 On-Board Refueling Vapor Recovery Rule[704]:

$$EF\ (g/gal) = \exp[-1.2798 - 0.0049(\Delta T) + 0.0203(Td) + 0.1315(RVP)] \qquad (1)$$

where delta T is the difference in temperature between the fuel in the tank and the fuel being dispensed, and Td is the temperature of the gasoline being dispensed. We assumed delta T is zero, temperature of the fuel being dispensed averages 60 degrees over the year, and that the RVP of conventional gasoline is 8.7 psi, 10% ethanol is 9.7, and 85% ethanol is 6.2. Using these assumptions, the adjustment factor is +14% for E10 and -30% for E85. Emission factors in grams per million BTU of fuel transferred are given in Table 3.1-20.

In addition to these Stage I emissions for gasoline and gasoline/ethanol blends, transport of ethanol to bulk terminals also results in evaporative emissions of ethanol, a VOC. For the NPRM analysis these emissions were estimated using a very simplified approach based on an adjustment to the gasoline transport VOC emissions to account for the much lower vapor pressure and molecular weight of ethanol versus gasoline. Using that method the NPRM assumed an emission factor of 3.56 g/mmBTU ethanol, which greatly underestimated the ethanol vapor and VOC losses, since it did not attempt to account for differences between ethanol and gasoline transport modes, distances, or transfer methods in movement of the fuel from production facility to the bulk distribution terminal.

For the air quality analysis and final rule analysis this method was replaced using data from an Oak Ridge National Laboratory (ORNL) analysis of projected ethanol transport modes, distances, and volumes transferred under various ethanol volume scenarios.[728] The final results of that study yielded greatly increased EFs of 26.9 - 31.7 g/mmBTU (2.04 - 2.41 g/gal) depending on the scenario, due to the added fuel transfer losses compared to pipeline-based transport of gasoline. The EF shown in Table 3.1-20 (28.78 g/mmBTU) corresponds to the High Ethanol minus RFS1 reference case, and was used for calculation of VOC and ethanol vapor for all cases in this FRM analysis. The air quality analysis used preliminary results of the ORNL analysis, which yielded somewhat greater ethanol and VOC emission rates than used for this FRM analysis. Further discussion of these calculations can be found in Section 3.3 of this RIA chapter.

Significant evaporative emissions are not expected from storage and transport of biodiesel fuel due to its low volatility.

### Table 3.1-20.
### VOC Emission Factors for Gasoline and Gasoline/Ethanol Blend Storage and Transfer Emissions (Stage 1)

| **Process** | **Blend** | **EF(g/mmBTU)** |
|---|---|---|
| Refinery to Bulk Terminal | E0 | 14.94 |
| Refinery to Bulk Terminal | E100 | 28.78[a] |
| Bulk Terminal to Pump | E0 | 27.79 |
| Bulk Terminal to Pump | E10 | 32.74 |
| Bulk Terminal to Pump | E85 | 25.93 |

[a] E100 ethanol vapor EF ranges from 26.9 - 31.7 depending on scenario. EF shown corresponds to the High Ethanol minus RFS1 reference case, and was used for calculation of all cases in this FRM analysis.

*Combustion Emissions from Transport and Distribution of Fuels and Feedstocks* -- Emissions are produced by the vehicles and engines used to transport feedstocks such as crude oil, corn, and cellulosic biomass to fuel production facilities, as well as transport/distribution of the finished fuels from the production plants to distribution terminals and retail outlets. For example, corn would be transported from farms and grain facilities to ethanol plants by truck and possibly rail. The finished ethanol would be transported from there to bulk distribution terminals by truck, rail, or barge, and distribution from terminal to retail outlet is by truck. The emission factors for the year 2022 in Table 3.1-21 are taken from the most recent rulemaking analyses, accounting for the mix of newer better controlled engines (including trucks meeting the standards for 2008 and later engines[705] and engines meeting the 2008 locomotive/marine diesel engine rule[706]), as well as any remaining older engines subject to less stringent standards. The truck EFs are given in terms of grams per vehicle mile traveled, while the other EFs are in grams per million BTU of fuel burned by the engine. The ocean tanker emission factors are from the base case analysis of the Category 3 ocean-going vessel proposed rule.[734]

To estimate the net emission rates for the assumed mix of transport modes for each fuel type, these emission factors were incorporated into a modified version of GREET[707], [708], since GREET 1.7 and 1.8 retained emission factors based only on earlier regulations. Thus, the miles traveled and quantities of fuel burned are those used by GREET for each transport mode and fuel being transported. For the final rule air quality analysis we will have a more detailed analysis of miles and fuel volumes transported by mode within each county.

**Table 3.1-21. 2022 Criteria Emissions from Fuel and Feedstock Transport/Distribution**

| Transport Mode | Year | VOC | CO | NOx | PM10 | PM2.5 |
|---|---|---|---|---|---|---|
| Class 2B HD Diesel Trucks (g/mile) | 2005 | 0.282 | 1.303 | 3.594 | 0.163 | 0.139 |
| | 2022 (2020) | 0.137 | 0.205 | 0.483 | 0.033 | 0.019 |
| Medium HD DIesel Trucks (g/mile) | 2005 | 0.653 | 2.482 | 8.297 | 0.309 | 0.271 |
| | 2022 (2020) | 0.289 | 0.417 | 1.243 | 0.053 | 0.035 |
| Locomotive (g/mmBTU of fuel burned) | 2005 | 84.733 | 212.861 | 1620.376 | 51.575 | 50.028 |
| | 2022 (2020) | 34.070 | 203.984 | 815.271 | 19.015 | 18.445 |
| Barge (avg of C1 & C2 vessels)[709] | 2005 | 26.761 | 237.513 | 1276.901 | 47.923 | 46.485 |
| (g/mmBTU of fuel burned) | 2022 (2020) | 15.527 | 188.994 | 676.097 | 22.017 | 21.356 |
| Ocean Tanker (C3 vessels) | 2005 | 79.298 | 180.314 | 2176.240 | 179.982 | 165.408 |
| (g/mmBTU of fuel burned) | 2022 (2020) | 79.160 | 179.525 | 2038.314 | 179.645 | 165.273 |

### 3.1.2.2 Upstream Air Toxics

#### 3.1.2.2.1 Upstream Air Toxics Reference Case

Air toxic emissions are associated with a variety of upstream processes. These processes include production of agricultural pesticides and fertilizers, as well as their application, operation of petroleum refineries, operation of ethanol and biodiesel production facilities, operation of electrical production facilities which supply power to these facilities, and distribution of agricultural pesticides and fertilizers, feedstocks, gasoline, gasoline/ethanol and biodiesel blends.

Although a large number of compounds which are considered air toxics could be impacted by this rule, we focused on those which were identified as national and regional-scale cancer and noncancer risk drivers in the 2002 NATA[710] and were also likely to be significantly impacted by this rule. These compounds include benzene, 1,3-butadiene, formaldehyde, acetaldehyde, and acrolein. Naphthalene impacts were included for petroleum refineries, since it is a significant emission product for those facilities. Ethanol impacts were also included in our analyses because of health concerns (Section 3.4.5) and its role as an acetaldehyde precursor.

2002 air toxic emissions for stationary sources, other than for fires, were obtained from the 2002 National Emissions Inventory (NEI), version 3. Future year emissions of benzene, 1,3-butadiene, formaldehyde, acetaldehyde, and acrolein were estimated for sectors only, rather than individual sources. These sectors included non-EGU (electric generating unit) point sources, EGU point sources, the nonpoint storage and transfer subsector, and other nonpoint sources. Emissions were estimated by applying the 2002 air toxics to VOC ratio to the future year VOC emission estimates. Air toxics from fires were estimated by applying toxics-to-VOC ratios to the VOC emissions from a fire inventory developed for air quality modeling. 2002 and future year ethanol emissions were estimated by speciating the VOC estimates. This was done using the Sparse Matrix Operator Kernel Emissions (SMOKE) modeling system, version 2.3. More details on the methods and data used to develop these inventories are found in a memo included in the docket for this rule.[711]

Air toxic emission estimates for agricultural equipment (mainly diesel agricultural tractors) were obtained from the EPA NMIM model, as described for criteria pollutants in Section 3.1.2.1.1.1.

### 3.1.2.2.2 Upstream Air Toxics Control Cases

As described below, we developed emission factors for several air toxics using the most recent available data. These emission factors were used with estimates of changes in fuel volumes and associated energy outputs to estimate inventory changes associated with the RFS2 volumes. In general, emission factors are expressed as grams per million BTU (g/mmBTU) of energy produced or distributed as part of the process. Underlying data are available in the docket for the rule.

*Agricultural Pesticides and Fertilizers* – The estimation of air toxic emissions from production and application of pesticides and fertilizers was done using toxic fractions of the corresponding VOC emissions described in Section 3.1.3.1.1.1. Table 3.1-22 shows the toxic fractions, which were calculated from the 2002 NEI inventories for VOC and each of the listed toxic pollutants. All the pollutants except acrolein from pesticide application are based on nationwide inventories. California was the only state that reported acrolein emissions associated with pesticide application, so the 0.66% value shown in the table represents the sum of acrolein emissions divided by the sum of VOC emissions from pesticide application for all counties in California in 2002. The fertilizer and pesticide application data come from queries of the NEI area source inventories for SCCs like "28017*" (for fertilizer application) and SCCs like "246180*" or like "246185*" (for pesticide application).

The production and blending data for fertilizer and pesticides come from queries of the NEI point source data that were submitted by 40 states and Puerto Rico for the following MACT codes:

0911 - Pesticide Active Ingredient Production
0960 - Agricultural Chemicals and Pesticides Manufacturing
1410 - Phosphate Fertilizers Production

The data for these codes was compiled for the following four categories: Fertilizer production (F), Fertilizer mixing blending (FMB), Pesticide production (P), and Pesticide mixing blending (PMB).

### Table 3.1-22. Air Toxic Fractions of VOC for Fertilizers and Pesticides

| | Fertilizer Production & Blending | Pesticide Production & Blending | Fertilizer Application | Pesticide Application |
|---|---|---|---|---|
| 1,3-Butadiene | -- | 0.0003653 | -- | -- |
| Acetaldehyde | 6.530 E-06 | 5.198 E-05 | -- | -- |
| Acrolein | 3.320 E-06 | 1.513 E-05 | -- | 0.0066 |
| Benzene | -- | 0.002038 | -- | 0.2615 |
| Ethanol | -- | -- | -- | -- |
| Formaldehyde | 0.007517 | 0.011494 | -- | -- |

*Petroleum Refineries* – Total nationwide emissions of air toxics for 153 U. S. petroleum refineries in 2002 were obtained from data collected as part of a risk and technology review (RTR) for EPA's proposed rule, "National Emission Standards for Hazardous Air Pollutants From Petroleum Refineries."[712] These emissions were divided by BTUs of energy produced by those refineries in 2002 to obtain emission factors in g/mmBTU. Thus the resultant emission factors represent 2002 technology and emission standards. Energy output estimates included all refinery products, such as conventional and reformulated gasoline, aviation gasoline, jet fuel, kerosene, distillate fuel oil, residual fuel oil, petrochemical feedstocks, naphthas, lubricants, and other miscellaneous products. Energy output was estimated by multiplying volume of each product supplied[713] by its heating value in BTUs per gallon.

Resultant emission factors are provided below in Table 3.1-24, along with those for ethanol and electricity production.

*Ethanol Production Facilities* – There are a number of processes at ethanol production facilities that result in emissions of air toxics. These processes include fermentation, distillation of the resultant mash, and drying of spent wet grain to produce animal feed. Emissions of air toxics vary tremendously from facility to facility due to a variety of factors, and it is difficult to determine how differences in the production processes individually impact emissions. Numerous production facilities have commenced operation in the last few years. To develop emission factors we used the most recent available inventory for benzene, formaldehyde, acetaldehyde, and acrolein, from calendar year 2005. These data were obtained from two sources:

1) 2005 NEI State submittals for SCCs associated with ethanol production facilities
2) the 2005 Toxics Release Inventory (TRI)

2005 NEI data submittals were obtained from EPA's Office of Air Quality Planning and Standards. These data are included in the docket for the rule. Additional data for facilities not included in these submittals were obtained from the 2005 TRI (http://www.epa.gov/triexplorer/list-chemical-hap.htm). Where emissions data were not available for a facility, the facility was excluded from subsequent calculations. It should be noted that not all States submitted data for ethanol production facilities, which could potentially introduce some bias into estimated emission rates.

Only a few facilities reported very low emissions of 1,3-butadiene, and the rest reported no emissions, so emissions of this pollutant from ethanol production facilities were assumed to be insignificant. Almost all of the data were from dry mill plants running on natural gas, so it was not possible to develop separate emission factors for wet and dry mill plants, or those running on coal or natural gas.

Energy output for each facility was estimated by multiplying production capacity by the heating value for ethanol. Since data on actual production by facility were not available, all plants were assumed to operate at capacity. Estimates of production capacity were obtained from data collected by the Renewable Fuels Association (http://www.ethanolrfa.org/industry/locations/). For some major ethanol producers production capacity was not available for specific facilities.

Data for facilities where both emissions and production capacity were available were used to estimate nationwide emission rates in g/mmBTU. Table 3.1-23 lists the number of ethanol production facilities with emissions data for various air toxics, as well as production capacity estimates.

**Table 3.1-23.**
**Number of Facilities with Emission Inventory Data**
**by Pollutant and Production Capacity Estimates**

| Pollutant | No. of Facilities with Emissions Data and Production Capacity Estimates. |
|---|---|
| Benzene | 30 |
| Formaldehyde | 35 |
| Acetaldehyde | 50 |
| Acrolein | 22 |

An emission factor for ethanol was estimated using data collected in Minnesota from 16 facilities, all of which were dry mill plants.[714] Since most ethanol emissions occur during fermentation, and new production of ethanol is likely to occur at dry mill facilities, these data are likely to provide representative estimates of future year increases in ethanol emissions under the control scenarios modeled. The resultant emission factors for ethanol production facilities are provided in Table 3.1-24.

Distillers' grains with solubles (DGS) is a co-product of dry mill corn ethanol production that can be used as animal feed. Corn oil remaining in the DGS can be extracted and sold for commercial uses, such as biodiesel production, at a relatively high value compared to the DGS itself. The oil can be extracted by gravimetric methods or by extraction with n-hexane, which is a potentially important toxic emission associated with increased ethanol production. Capital costs for solvent extraction are higher, but so are yields.

Corn oil for food grade use is produced by a process wherein corn is separated into component parts, prior to fermentation, with the starch heavy dehulled-degermed corn portion fed to the ethanol plant and the corn germ fed to a hexane-based corn oil extraction facility. This process is capital intensive and must be designed into the plant. We expect the food grade extraction process to be less widespread than commercial grade processes for these reasons.

VeraSun recently submitted an application to the Iowa Department of Natural Resources (IDNR) to add a facility for solvent extraction of corn oil to an ethanol plant in Fort Dodge Iowa.[715] In this application, Verasun proposed to control particulate matter emissions from the process using a baghouse, and to minimize VOC emissions through good design and operating processes. Verasun estimated that this plant, with an annual DDGS capacity of 455,000 tons of DDGS per year, would produce 305 tons of VOCs per year, with n-hexane emissions of 295 tons per year. $PM_{10}$ emissions would be about 13 tons.

EPA used the Verasun application data to develop an estimate of potential nationwide n-hexane emissions from ethanol plants nationwide. EPA estimates that about 40% of ethanol production will have corn oil extraction by 2022; thus, we assumed that about half of this would be from solvent extraction and 20% of dry mill plants would employ this process. It is likely a number of plants will use gravimetric recovery, since it can be easily retrofitted to any size plant at modest capital cost. First, we developed emission rates per ton of DDGS production. Then we developed an estimate of DDGS produced nationwide, using industry characterization estimates of 13.67 billion gallons of dry mill ethanol production in 2022, and 0.00334 tons DDGS per gallon of ethanol produced by dry mills.[716] Multiplying the emission rate from the Verasun application by total production of DDGS, EPA estimates these facilities could emit about 9,000 tons of n-hexane nationwide. However, given the very limited data on emissions from such facilities and the nascent nature of this process at ethanol production facilities, such estimates should be regarded as highly uncertain.

*Biodiesel Production Facilities* -- To estimate emission factors for biodiesel production facilities, we identified air toxic emission data for individual facilities developed for the 2005 NEI. Unfortunately, only toxics data for two existing biodiesel facilities could be found. These data were used to develop toxic to VOC ratios, then applied to VOC emission factors for biodiesel plants obtained from GREET, with modifications to add energy used in crushing soybeans. VOC emission rates vary by feedstock. Toxic to VOC ratios, VOC emission rates, and resultant toxic emission rates in grams per gallon are given in Table 3.1-25.

*Transportation and Distribution of Gasoline, Ethanol, Gasoline/Ethanol Blends and Biodiesel* -- Air toxic emissions associated with distributing fuel and fuel blends come from two sources. The first source is evaporative, spillage and permeation emissions from storage and transfer activities, and the second source is emissions from vehicles and pipeline pumps used to transport the fuels. Since a pipeline system does not exist for ethanol, increased ethanol use is likely to increase toxic emissions from vehicles used to transport it, while a corresponding decrease in gasoline distribution would decrease any emissions related to pipeline pumping.

Storage and transfer activities result in evaporative emissions of benzene and ethanol from gasoline, ethanol, and gasoline/ethanol blends. Evaporative emissions from biodiesel fuel are not expected to be significant. Emissions of ethanol occur both during transport of ethanol from production facilities to bulk terminals, and after blending, at bulk terminals. In addition, emission factors for benzene must be estimated separately for fuel before and after blending. As previously discussed, we assumed bulk terminal emissions were associated with unblended gasoline. We then divided emissions into a refinery to bulk terminal component and a bulk terminal to dispensing facility component. Benzene emission factors for gasoline transport from refinery to bulk terminals were weighted by the fraction of 2002 VOC emissions for this part of the process, whereas emission factors for E0 gasoline, E10 gasoline, and E85 were weighted by the fraction of 2002 VOC from the bulk terminal to the pump. Benzene emission rates from these activities also vary with the year being modeled, since phase-in of the recently finalized Mobile Source Air Toxics Rule will substantially reduce the amount of benzene in gasoline beginning in 2011.[717] Thus, one set of emission factors were developed for 2002, and a separate set of emission factors for the reference case in that year. The reference case also includes impacts of the 2007 renewable fuels standard.[718] Thus, the reference case already reflects ethanol volumes mandated by RFS1.

The emission factors used for 2002 were derived from the estimated gasoline distribution inventory for benzene in 1999, estimated for the Mobile Source Air Toxics Rule.[719] Total nationwide emissions were divided by the energy content of the total volume of gasoline distributed in 1999, to obtain the emission factor in g/mmBTU. Total volume of gasoline was based on gasoline sales as reported by the Energy Information Administration.[720] To estimate the energy content, sales of fuel types (conventional, Federal reformulated, California reformulated) were multiplied by their respective heating values.

The emission factors used for the reference case in 2022 were derived from an estimated gasoline distribution inventory for that year. This inventory estimate was calculated by linear interpolation of 2020 and 2030 inventories from the Mobile Source Air Toxics Rule. Total nationwide emissions were divided by the energy content of the total volume of gasoline projected for 2022 by the Energy Information Administration.[721] To estimate the energy content, the projected gasoline volume was multiplied by the heating value for low-sulfur gasoline (115,000 BTU/gallon).

We assumed that in order to attain the fuel benzene standard for gasoline promulgated in the Mobile Source Air Toxics Rule, E10 would have the same fuel benzene content per gallon as E0 . However, for E10 the E0 emission factor was adjusted to account for the lower energy content of E10 relative to E0. For E85, the E0 emission factor was adjusted to account for 66% lower benzene emissions per gallon, as well as the lower energy content of E85.

The emission factors for benzene are provided in Table 3.1-26.

To estimate ethanol emissions associated with the distribution of E10 and E85, ethanol to benzene emission ratios were applied to benzene estimates. The ratios were 14.8 for E10 and 112.8 for E85. The ratio for E10 was obtained from the profile for composite evaporative emissions from U. S. EPA’s SPECIATE database, profile 1301.[722] The ratio for E85 was obtained from analyses of evaporative emissions from three vehicles tested as part of the Auto/Oil program in the early 1990’s.[723] These emission factors are reported in Table 3.1-26.

### Table 3.1-24. Air Toxic Emission Factors for Petroleum Refineries, Ethanol Refineries, and Electricity Production (g/mmBTU of fuel or electricity produced)

| Pollutant | Petroleum Refinery | Ethanol refinery | Electricity Production |
|---|---:|---:|---:|
| 1,3-butadiene | 0.0014 | N. A. | 0.0001 |
| Acetaldehyde | 0.0002 | 3.0585 | 0.0297 |
| Acrolein | 0.0001 | 0.1323 | 0.0115 |
| Benzene | 0.0264 | 0.0998 | 0.0443 |
| Ethanol | 0.0000 | 21.6858 | |
| Formaldehyde | 0.0042 | 0.5263 | 0.0629 |
| Naphthalene | 0.0029 | | |

### Table 3.1-25. Air Toxic Emission Factors for Biodiesel Production Facilities (g/gallon produced)

| Pollutant | Toxic/VOC Ratio | Biodiesel Soybean Oil EF (g/gal) | Biodiesel Yellow Grease/tallow (g/gal) | Renewable Biodiesel Soybean Oil (g/gal) |
|---|---:|---:|---:|---:|
| VOC | | 0.040 | 0.042 | 0.029 |
| Benzene | $7.4\text{x}10^{-7}$ | $3.0\text{x}10^{-8}$ | $3.1\text{x}10^{-8}$ | $2.1\text{x}10^{-8}$ |
| 1,3-Butadiene | 0 | 0 | 0 | 0 |
| Formaldehyde | $3.5\text{x}10^{-5}$ | $1.4\text{x}10^{-6}$ | $1.5\text{x}10^{-6}$ | $1.0\text{x}10^{-6}$ |
| Acetaldehyde | $5.6\text{x}10^{-6}$ | $2.3\text{x}10^{-7}$ | $2.4\text{x}10^{-7}$ | $1.6\text{x}10^{-7}$ |
| Acrolein | $4.8\text{x}10^{-6}$ | $1.9\text{x}10^{-7}$ | $2.0\text{x}10^{-7}$ | $1.4\text{x}10^{-7}$ |
| Ethanol | 0 | 0 | 0 | 0 |
| Naphthalene | $6.3\text{x}10^{-7}$ | $2.5\text{x}10^{-8}$ | $2.6\text{x}10^{-8}$ | $1.8\text{x}10^{-8}$ |

**Table 3.1-26. Air Toxic Evaporative Emission Factors for Gasoline, Ethanol, and Blend Transport and Distribution (g/mmBTU of fuel transported)**

| Pollutant | Process | Year | Fuel | EF (g/mmBTU) |
|---|---|---|---|---|
| **Benzene** | Refinery to Bulk Terminal | 2002 | E0 | 0.0488 |
| | Refinery to Bulk Terminal | 2022 | E0 | 0.0270 |
| | Bulk Terminal to Pump | 2002 | E0 | 0.0908 |
| | Bulk Terminal to Pump | 2022 | E0 | 0.0502 |
| | Bulk Terminal to Pump | 2022 | E10 | 0.0519 |
| | Bulk Terminal to Pump | 2022 | E85 | 0.0228 |
| **Ethanol** | Bulk Terminal to Pump | 2022 | E10 | 1.8591 |
| | Bulk Terminal to Pump | 2022 | E85 | 7.1432 |

As mentioned previously, ethanol vapor emissions during transport from the ethanol plant to the bulk terminal are based on an adjustment to the gasoline transport VOC emissions to account for the much lower vapor pressure and molecular weight.

There are also toxic emissions associated with combustion of fuels used in transport and distribution of feedstocks and fuels. The emission factors for these are shown in Table 3.1-27 as fractions of exhaust VOC, or PM10 for exhaust naphthalene. The VOC and PM10 emission factors that these fractions are applied to are presented above in Table 3.1-21. The locomotive, marine distillate, and residual boiler estimates come from a 2005 EPA report.[724] The heavy-duty diesel truck emission fractions come from a 2002 report documenting the toxics module of EPA's MOBILE6.2 model,[725] and the pipeline values come from the EPA AP-42 document.[726]

**Table 3.1-27.**
**Toxic Fractions of Exhaust VOC (or fraction of PM10 for exhaust naphthalene)**
**(grams toxics per gram of VOC or PM10)**

| Mode | Source | 1,3-Butadiene | Acetaldehyde | Acrolein | Benzene | Formaldehyde | Naphthalene |
|---|---|---|---|---|---|---|---|
| Rail | Diesel Locomotive | 0.003246519 | 0.018786 | 0.0031238 | 0.002587511 | 0.04328653 | 0.0018716 |
| Barge | Marine Diesel – Distillate | 0.00061 | 0.074298 | 0.0035 | 0.020344 | 0.1496 | 0.0018716 |
| Ocean Tanker | Residual Boiler | 0 | 0.003858 | 0 | 0.000165354 | 0.02645669 | 0.0025885 |
| Truck | HD Diesel Trucks | 0.00061 | 0.0288 | 0.0035 | 0.0105 | 0.0782 | 0.00128892 |
| Pipeline | Natural Gas Turbines | 0 | 0.019048 | 0.0030476 | 0.005714286 | 0.33809524 | |
| Gasoline Farm Equip | HD Gasoline Trucks | | | | | | 0.088005387 |

## 3.2 Non-GHG Emission Impact Results

### 3.2.1 U.S. Total Reference Case Inventories for All Sectors (AEO 2007 only)

The reference case emission inventories used for this final rule analysis are based on different sources depending on sector, and for most sectors they match what was used for the proposed rule and air quality analysis.

For stationary/area sources and aircraft we used the 2002 National Emissions Inventory (NEI), Version 3, including the NEI projections for 2020. The development of these inventories is documented in the November 27, 2007, memo titled, “Approach for Developing 2002 and Future Year National Emission Summaries,” from Madeleine Strum to Docket EPA-HQ-OAR-2007-0491. That memo summarizes the methodologies and additional reference documents for criteria air pollutants (CAP) and mobile source air toxics (MSATs).

For onroad mobile sources we used a special version of the MOVES model that estimates emissions from light-duty and heavy-duty gasoline vehicles, except for motorcycles. For other onroad vehicles including diesel vehicles and motorcycles, we relied on the MOBILE6.2 model as run using the NMIM platform with county specific fuel properties and temperatures. Most nonroad equipment was modeled with NONROAD2005d using NMIM, which is a version of the NONROAD that includes the benefits of the two nonroad regulations published in 2008 (the locomotive and marine diesel rule and the small spark-ignition and recreational marine engine rule).

Inventories for locomotives and commercial marine vessels are not covered by the NONROAD model, and they have been updated since the 2002 NEI was published. Thus we used the more recent inventories published in the regulatory impact analyses of their respective recent rulemakings. Locomotives and C1/C2 commercial marine vessel inventories come from the spring 2008 final rule, and the C3 commercial marine emission inventory is from the Notice of Proposed Rulemaking (NPRM) published in August 2009.[734]

Table 3.2-1 shows the total 2022 mobile and non-mobile source inventory projections that were used as the basis for the impact percentages shown above in Table 3.2-1 through 3.2-4. The mobile source values in this table use the inventory values of the AEO 2007 reference case.

**Table 3.2-1. 2022 AEO 2007 Reference Case Emissions by Sector**

| | VOC | CO | NOx | PM10 | PM2.5 | SO2 | NH3 |
|---|---|---|---|---|---|---|---|
| Onroad Gasoline | 981,432 | 26,547,169 | 2,001,543 | 46,284 | 42,619 | 34,031 | 390,486 |
| Onroad Diesel | 140,854 | 243,820 | 1,307,150 | 62,253 | 37,357 | 4,352 | 11,426 |
| Nonroad Gasoline | 1,440,414 | 14,924,581 | 269,443 | 56,660 | 52,305 | 1,836 | 1,112 |
| Other Nonroad[a] | 270,707 | 1,402,948 | 3,353,753 | 230,305 | 209,516 | 1,026,510 | 3,034 |
| Stationary/Area | 8,740,057 | 11,049,239 | 5,773,927 | 3,194,610 | 3,047,714 | 7,864,681 | 3,839,925 |
| Total | 11,573,464 | 54,167,758 | 12,705,817 | 3,590,112 | 3,389,512 | 8,931,411 | 4,245,983 |

| Table 3.2-1 continued | Benzene | Ethanol | 1,3-Butadiene | Acetal-dehyde | Formal-dehyde | Naphthalene | Acrolein |
|---|---|---|---|---|---|---|---|
| Onroad Gasoline | 33,607 | 15,985 | 4,487 | 6,455 | 10,681 | 3,787 | 513 |
| Onroad Diesel | 1,749 | 0 | 958 | 3,857 | 10,589 | 20 | 513 |
| Nonroad Gasoline | 26,193 | 66,150 | 4,935 | 4,033 | 7,245 | 713 | 436 |
| Other Nonroad[a] | 3,815 | 5,294 | 939 | 9,550 | 22,355 | 24 | 1,021 |
| Stationary/Area | 111,337 | 462,566 | 1,847 | 13,118 | 23,846 | 9,404 | 3,412 |
| Total | 176,701 | 549,995 | 13,166 | 37,013 | 74,716 | 13,949 | 5,895 |

[a] Nonroad diesel, LPG, CNG engines and all locomotive, aircraft, and commercial marine

### 3.2.2 2022 RFS2 Total Non-GHG Emission Inventory Impacts

Our projected overall emission impacts for each of the analyzed RFS2 renewable fuel scenarios are shown in Table 3.2-2 and Table 3.2-3 for 2022, showing the expected emission changes for the U.S. relative to each of the reference cases. The percent contribution of these impacts relative to the total U.S. inventory across all sectors is also shown, using the AEO 2007 reference case totals from Table 3.2-1. .

## Table 3.2-2.
## RFS2 Emission Impacts in 2022 Relative to the AEO2007 Reference Case

| Pollutant | Low Ethanol Scenario | | Mid (Primary) Ethanol Scenario | | High Ethanol Scenario | |
|---|---|---|---|---|---|---|
| | Annual Short Tons | % of Total US Inventory | Annual Short Tons | % of Total US Inventory | Annual Short Tons | % of Total US Inventory |
| NOx | 208,316 | 1.64% | 184,820 | 1.45% | 131,124 | 1.03% |
| HC | 20,123 | 0.17% | 24,523 | 0.21% | 35,342 | 0.31% |
| PM10 | 71,779 | 2.00% | 63,323 | 1.76% | 44,099 | 1.23% |
| PM2.5 | 17,355 | 0.51% | 14,393 | 0.42% | 7,678 | 0.23% |
| CO | -364,400 | -0.67% | -376,419 | -0.69% | -404,199 | -0.75% |
| Benzene | -979 | -0.55% | -1,004 | -0.57% | -1,056 | -0.60% |
| Ethanol | 33,749 | 6.14% | 54,137 | 9.84% | 102,359 | 18.61% |
| 1,3-Butadiene | 59 | 0.45% | 59 | 0.45% | 59 | 0.45% |
| Acetaldehyde | 1,978 | 5.34% | 3,108 | 8.40% | 5,757 | 15.56% |
| Formaldehyde | 113 | 0.15% | 130 | 0.17% | 170 | 0.23% |
| Naphthalene | -4 | -0.03% | -4 | -0.03% | -4 | -0.03% |
| Acrolein | 16 | 0.28% | 21 | 0.35% | 31 | 0.53% |
| SO2 | 20,456 | 0.23% | 5,065 | 0.06% | -30,058 | -0.34% |
| NH3 | 48,711 | 1.15% | 48,711 | 1.15% | 48,709 | 1.15% |

## Table 3.2-3.
## RFS2 Emission Impacts in 2022 Relative to the RFS1 Mandate Reference Case

| Pollutant | Low Ethanol Scenario | | Mid (Primary) Ethanol Scenario | | High Ethanol Scenario | |
|---|---|---|---|---|---|---|
| | Annual Short Tons | % of Total US Inventory | Annual Short Tons | % of Total US Inventory | Annual Short Tons | % of Total US Inventory |
| NOx | 271,100 | 2.13% | 247,604 | 1.95% | 193,907 | 1.53% |
| HC | 96,362 | 0.83% | 100,762 | 0.87% | 111,581 | 0.96% |
| PM10 | 77,469 | 2.16% | 69,013 | 1.92% | 49,791 | 1.39% |
| PM2.5 | 18,511 | 0.55% | 15,549 | 0.46% | 8,834 | 0.26% |
| CO | -2,857,823 | -5.28% | -2,869,842 | -5.30% | -2,897,622 | -5.35% |
| Benzene | -4,240 | -2.40% | -4,264 | -2.41% | -4,316 | -2.44% |
| Ethanol | 79,736 | 14.50% | 100,123 | 18.20% | 148,345 | 26.97% |
| 1,3-Butadiene | 224 | 1.70% | 224 | 1.70% | 224 | 1.70% |
| Acetaldehyde | 4,718 | 12.75% | 5,848 | 15.80% | 8,497 | 22.96% |
| Formaldehyde | 338 | 0.45% | 355 | 0.48% | 395 | 0.53% |
| Naphthalene | -1 | 0.00% | -1 | -0.01% | -1 | 0.00% |
| Acrolein | 18 | 0.31% | 22 | 0.38% | 33 | 0.56% |
| SO2 | 18,678 | 0.21% | 3,286 | 0.04% | -31,836 | -0.36% |
| NH3 | 48,711 | 1.15% | 48,711 | 1.15% | 48,709 | 1.15% |

Fuel production and distribution emission impacts of the RFS2 program were estimated in conjunction with the development of life cycle GHG emission impacts, and the GHG emission inventories discussed in Chapter 2. These emissions are calculated according to the breakdowns of agriculture, feedstock transport, fuel production, and fuel distribution; the basic calculation is a function of fuel volumes in the analysis year and the emission factors associated with each process or subprocess. Additionally, the emission impact of displaced petroleum is estimated, using the same domestic/import shares discussed in chapter 2.

In general the basis for this life cycle evaluation was the analysis conducted as part of the Renewable Fuel Standard (RFS1) rulemaking, but enhanced significantly. While our approach for the RFS1 was to rely heavily on the "Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation" (GREET) model, developed by the Department of Energy's Argonne National Laboratory (ANL), we are now able to take advantage of additional information and models to significantly strengthen and expand our analysis for this rule. In particular, the modeling of the agriculture sector was greatly expanded beyond the RFS1 rule analysis, employing economic and agriculture models to consider factors such as land-use impact, agricultural burning, fertilizer, pesticide use, livestock, crop allocation, and crop exports.

Other updates and enhancements to the GREET model assumptions include updated emission factors for NOx, CO, and SO2 from new cellulosic ethanol plant modeling by the National Renewable Energy Laboratory (NREL), and updated fuel and feedstock transport emission factors that account for recent EPA emission standards and modeling, such as the Tier 4 diesel truck standards published in 2004 and the locomotive and commercial marine standards finalized in 2008. Emission factors for new corn ethanol plants continue to use the values developed for the RFS1 rule, which were based on data submitted by states for dry mill plants. There are no new standards planned at this time that would offer any additional control of emissions from corn or cellulosic ethanol plants. In addition, GREET does not include air toxics or ethanol. Thus emission factors for ethanol and the following air toxics were added: benzene, 1,3-butadiene, formaldehyde, acetaldehyde, acrolein and naphthalene.

Results of these calculations relative to each of the reference cases for 2022 are shown in Table 3.2-4 and Table 3.2-5 for the criteria pollutants, ammonia, ethanol and individual air toxic pollutants. It should be noted that the impacts relative to the RFS1 reference case use the same agricultural impacts as for the AEO 2007 reference case, since there was no agricultural modeling done for the RFS1 case. Due to the complex interactions involved in projections in agricultural modeling, it was not considered reasonable to attempt any sort of proportional adjustments to the AEO 2007 agricultural projections to approximate the RFS1 case.

The fuel production and distribution impacts of today's rule on VOC are mainly due to increases in emissions connected with biofuel production, countered by decreases in emissions associated with gasoline production and distribution as ethanol displaces some of the gasoline. Increases in PM2.5, SOx and especially NOx are driven by stationary combustion emissions from the substantial increase in corn and cellulosic ethanol production. Biofuel plants (corn and cellulosic) tend to have greater combustion emissions relative to petroleum refineries on a per-BTU of fuel produced basis. Increases in SOx emissions are also due to increases in agricultural chemical production and transport, while substantial PM increases are also associated with fugitive dust from agricultural operations. Ammonia emissions are expected to increase substantially due to increased ammonia from fertilizer use.

Ethanol vapor and most air toxic emissions associated with fuel production and distribution are projected to increase. Relative to the US total reference case emissions with RFS1 mandate ethanol volumes, the primary RFS2 control case is estimated to yield increases of 4-13 percent for acetaldehyde and ethanol vapor, driven directly by the increased ethanol production and distribution. Formaldehyde and acrolein increases are smaller, on the order of 0.4-1 percent. There are also very small decreases in benzene, 1,3-butadiene and naphthalene relative to the US total emissions.

**Table 3.2-4. Fuel Production and Distribution Impacts for 2022 RFS2 Control Cases Relative to the AEO 2007 Reference Case**

| Pollutant | **Low Ethanol Scenario** | | **Mid (Primary) Ethanol Scenario** | | **High Ethanol Scenario** | |
|---|---|---|---|---|---|---|
| | Annual Short Tons | % of Total US Inventory | Annual Short Tons | % of Total US Inventory | Annual Short Tons | % of Total US Inventory |
| NOx | 187,666 | 1.48% | 164,170 | 1.29% | 110,473 | 0.87% |
| HC | 16,604 | 0.14% | 19,737 | 0.17% | 27,547 | 0.24% |
| PM10 | 72,348 | 2.02% | 63,892 | 1.78% | 44,669 | 1.24% |
| PM2.5 | 17,670 | 0.52% | 14,707 | 0.43% | 7,993 | 0.24% |
| CO | 142,191 | 0.26% | 130,172 | 0.24% | 102,392 | 0.19% |
| Benzene | -208 | -0.12% | -236 | -0.13% | -298 | -0.17% |
| Ethanol | 20,291 | 3.69% | 35,865 | 6.52% | 72,815 | 13.24% |
| 1,3-Butadiene | 0 | 0.00% | 0 | 0.00% | 0 | 0.00% |
| Acetaldehyde | 823 | 2.22% | 933 | 2.52% | 1,193 | 3.22% |
| Formaldehyde | 170 | 0.23% | 187 | 0.25% | 227 | 0.30% |
| Naphthalene | -5 | -0.04% | -6 | -0.04% | -7 | -0.05% |
| Acrolein | 33 | 0.56% | 37 | 0.63% | 48 | 0.81% |
| SO2 | 20,435 | 0.23% | 5,044 | 0.06% | -30,078 | -0.34% |
| NH3 | 48,711 | 1.15% | 48,711 | 1.15% | 48,709 | 1.15% |

**Table 3.2-5. Fuel Production and Distribution Impacts for 2022 RFS2 Control Cases Relative to the RFS1 Mandate Reference Case**

| Pollutant | Low Ethanol Scenario | | Mid (Primary) Ethanol Scenario | | High Ethanol Scenario | |
|---|---|---|---|---|---|---|
| | Annual Short Tons | % of Total US Inventory | Annual Short Tons | % of Total US Inventory | Annual Short Tons | % of Total US Inventory |
| NOx | 193,161 | 1.52% | 169,665 | 1.34% | 115,969 | 0.91% |
| HC | 73,881 | 0.64% | 77,014 | 0.67% | 84,825 | 0.73% |
| PM10 | 78,039 | 2.17% | 69,583 | 1.94% | 50,360 | 1.40% |
| PM2.5 | 18,826 | 0.56% | 15,864 | 0.47% | 9,149 | 0.27% |
| CO | 147,677 | 0.27% | 135,658 | 0.25% | 107,878 | 0.20% |
| Benzene | -203 | -0.12% | -231 | -0.13% | -294 | -0.17% |
| Ethanol | 53,871 | 9.79% | 69,445 | 12.63% | 106,395 | 19.34% |
| 1,3-Butadiene | -1 | -0.01% | -1 | -0.01% | -1 | -0.01% |
| Acetaldehyde | 1,507 | 4.07% | 1,617 | 4.37% | 1,877 | 5.07% |
| Formaldehyde | 276 | 0.37% | 293 | 0.39% | 333 | 0.45% |
| Naphthalene | -7 | -0.05% | -8 | -0.06% | -9 | -0.06% |
| Acrolein | 62 | 1.06% | 67 | 1.13% | 77 | 1.31% |
| SO2 | 18,657 | 0.21% | 3,266 | 0.04% | -31,857 | -0.36% |
| NH3 | 48,711 | 1.15% | 48,711 | 1.15% | 48,709 | 1.15% |

A breakout of these upstream emissions by where they occur in the production/distribution chain is shown in Table 3.2-6. The displaced gasoline line of this table refers to the impacts of decreasing the petroleum based gasoline and diesel fuel production as some of the needed energy is replaced with ethanol and biodiesel fuels.

**Table 3.2-6. Emission Inventory Impacts by Fuel Production/Distribution Segment for the Primary RFS2 Control Case Relative to the AEO 2007 Reference Case (annual short tons)**

| | VOC | CO | NOx | PM10 | PM2.5 | SO2 | NH3 |
|---|---:|---:|---:|---:|---:|---:|---:|
| Agriculture | 2,398 | 11,831 | 6,597 | 56,512 | 9,169 | 22,157 | 48,709 |
| Biofuel Feedstock Transport | 355 | 508 | 1,440 | 239 | 106 | 584 | 0 |
| Biofuel Production | 18,867 | 129,586 | 193,040 | 22,621 | 11,241 | 8,932 | 2 |
| Biofuel Transport & Distribution | 18,041 | 3,316 | 7,599 | 323 | 219 | 962 | 0 |
| Displaced gasoline | -19,925 | -15,069 | -44,506 | -15,803 | -6,028 | -27,591 | 0 |
| Total Upstream | 19,737 | 130,172 | 164,170 | 63,892 | 14,707 | 5,044 | 48,711 |

| **Table 3.2-6 continued** | **Benzene** | **Ethanol** | **1,3-Butadiene** | **Acetal-dehyde** | **Formal-dehyde** | **Naphthalene[b]** | **Acrolein** |
|---|---:|---:|---:|---:|---:|---:|---:|
| Agriculture | -145.8 | 0 | 1.99 | 13.51 | 47.89 | 0.73 | -3.24 |
| Biofuel Feedstock Transport | 3.73 | 0 | 0.22 | 10.24 | 27.80 | 0.31 | 1.24 |
| Biofuel Production | 28.86 | 6,435 | 0.01 | 906.9 | 154.9 | 0.02 | 39.01 |
| Biofuel Transport & Distribution | -30.84 | 29,430 | 1.18 | 11.01 | 25.67 | 0.57 | 1.46 |
| Displaced gasoline | -91.80 | 0 | -3.84 | -8.72 | -69.50 | -7.55 | -1.27 |
| Total Upstream | -235.8 | 35,865 | -0.44 | 933.0 | 186.8 | -5.92 | 37.21 |

Tables 3.2-7 and 3.2-8 summarize the vehicle and equipment emission impacts in 2022, including the biodiesel impacts. Table 3.2-9 shows that the biodiesel contribution to these impacts is quite small; as noted earlier, using MOVES2010 as baseline emissions for diesels would likely double the NOx and PM impacts relative to the NMIM-based impacts shown While the three fuel effect scenarios were only modeled for passenger cars and trucks, these totals reflect the net emissions from all mobile sources, including passenger cars and trucks, heavy duty trucks, off-road sources and portable fuel containers, using the same emissions in all three cases for the non-passenger car/truck categories. A full description of the basis of these vehicle and equipment emission impacts is given in Section 3.1.1 of this document.

Carbon monoxide, benzene, and acrolein are projected to decrease in 2022 under today's rule, while NOx, HC and the other air toxics, especially ethanol and acetaldehyde, are projected to increase due to the impacts of E10.

## Table 3.2-7.
## 2022 Vehicle and Equipment Emission Impacts for the RFS2 Control Cases Relative to the AEO 2007 Reference Case

| Pollutant | **Low Ethanol Scenario** | | **Mid (Primary) Ethanol Scenario** | | **High Ethanol Scenario** | |
|---|---|---|---|---|---|---|
| | Annual Short Tons | % of Total US Inventory | Annual Short Tons | % of Total US Inventory | Annual Short Tons | % of Total US Inventory |
| NOx | 20,650 | 0.16% | 20,650 | 0.16% | 20,650 | 0.16% |
| HC | 3,519 | 0.03% | 4,786 | 0.04% | 7,795 | 0.07% |
| PM10 | -569 | -0.02% | -569 | -0.02% | -569 | -0.02% |
| PM2.5 | -315 | -0.01% | -315 | -0.01% | -315 | -0.01% |
| CO | -506,591 | -0.94% | -506,591 | -0.94% | -506,591 | -0.94% |
| Benzene | -771 | -0.44% | -768 | -0.43% | -758 | -0.43% |
| Ethanol | 13,459 | 2.45% | 18,272 | 3.32% | 29,544 | 5.37% |
| 1,3-Butadiene | 59 | 0.45% | 59 | 0.45% | 59 | 0.45% |
| Acetaldehyde | 1,155 | 3.12% | 2,175 | 5.88% | 4,564 | 12.33% |
| Formaldehyde | -57 | -0.08% | -57 | -0.08% | -57 | -0.08% |
| Naphthalene | 2 | 0.01% | 2 | 0.01% | 3 | 0.02% |
| Acrolein | -16 | -0.28% | -16 | -0.28% | -16 | -0.28% |
| SO2 | 21 | 0.00% | 21 | 0.00% | 21 | 0.00% |
| NH3 | 0 | 0.00% | 0 | 0.00% | 0 | 0.00% |

### Table 3.2-8.
### 2022 Vehicle and Equipment Emission Impacts for the RFS2 Control Cases Relative to RFS1 Mandate Reference Case

| Pollutant | Low Ethanol Scenario | | Mid (Primary) Ethanol Scenario | | High Ethanol Scenario | |
|---|---|---|---|---|---|---|
| | Annual Short Tons | % of Total US Inventory | Annual Short Tons | % of Total US Inventory | Annual Short Tons | % of Total US Inventory |
| NOx | 77,939 | 0.61% | 77,939 | 0.61% | 77,939 | 0.61% |
| HC | 22,480 | 0.19% | 23,748 | 0.21% | 26,756 | 0.23% |
| PM10 | -569 | -0.02% | -569 | -0.02% | -569 | -0.02% |
| PM2.5 | -315 | -0.01% | -315 | -0.01% | -315 | -0.01% |
| CO | -3,005,500 | -5.55% | -3,005,500 | -5.55% | -3,005,500 | -5.55% |
| Benzene | -4,036 | -2.28% | -4,033 | -2.28% | -4,022 | -2.28% |
| Ethanol | 25,864 | 4.70% | 30,678 | 5.58% | 41,950 | 7.63% |
| 1,3-Butadiene | 225 | 1.71% | 225 | 1.71% | 225 | 1.71% |
| Acetaldehyde | 3,210 | 8.67% | 4,231 | 11.43% | 6,620 | 17.89% |
| Formaldehyde | 62 | 0.08% | 62 | 0.08% | 62 | 0.08% |
| Naphthalene | 7 | 0.05% | 7 | 0.05% | 8 | 0.06% |
| Acrolein | -44 | -0.75% | -44 | -0.75% | -44 | -0.75% |
| SO2 | 21 | 0.00% | 21 | 0.00% | 21 | 0.00% |
| NH3 | 0 | 0.00% | 0 | 0.00% | 0 | 0.00% |

### Table 3.2-9.
### 2022 Biodiesel Emission Impacts for All RFS2 Control Cases Relative to Reference Cases
### (these impacts are included in Tables 3.2-7 and 3.2-8)

| Pollutant | **Biodiesel Impacts** |
|---|---|
| | Annual Short Tons |
| NOx | 1,346 |
| HC | -2,422 |
| PM10 | -569 |
| PM2.5 | -315 |
| CO | -4,104 |
| Benzene | -30.08 |
| Ethanol | 0.00 |
| 1,3-Butadiene | -16.48 |
| Acetaldehyde | -66.34 |
| Formaldehyde | -182.09 |
| Naphthalene | -0.38 |
| Acrolein | -8.82 |
| SO2 | 0 |
| NH3 | 0 |

Table 3.2-10 shows a breakout of the relative impacts of the RFS2 volumes on the various types of vehicle and equipment emissions for the primary (mid-ethanol) case relative to the AEO 2007 reference case. The gasoline vehicle exhaust emission values were generated by MOVES, while the NMIM model was used to generate the other vehicle and equipment emission impacts. The impacts on portable fuel container emissions were estimated using an analysis of available data, adjusted for the ethanol and gasoline fuel volumes in this rule. The methods used are described above in Section 3.1.1. The substantial CO reductions and NOx and ethanol increases from light-duty vehicles and nonroad gasoline equipment are due to the effects of increased E10 marketshare with no E0 remaining in the market. Evaporative and refueling vapor emissions only include VOC, ethanol, benzene, and naphthalene.

## Table 3.2-10. Vehicle and Equipment Emission Inventory Impacts by Source Type for the Primary RFS2 Control (mid-ethanol) Case Relative to the AEO 2007 Reference Case (annual short tons)

| | VOC[a] | CO | NOx | PM10 | PM2.5 | SO2 | NH3 |
|---|---|---|---|---|---|---|---|
| Light-duty gasoline vehicle exhaust | -1,437 | -72,872 | 10,034 | 0.0 | 0.0 | 0.0 | 0.0 |
| Light-duty gasoline vehicle evap | 3,447 | n/a [b] | n/a | n/a | n/a | n/a | n/a |
| Light-duty gasoline vehicle refueling | 2,015 | n/a | n/a | n/a | n/a | n/a | n/a |
| Heavy-duty gasoline vehicle exhaust | 2,168 | -21,163 | 58 | 0.0 | 0.0 | 0.0 | 0.0 |
| Heavy-duty gasoline vehicle evap | -750 | n/a | n/a | n/a | n/a | n/a | n/a |
| Heavy-duty gasoline vehicle refueling | 440 | n/a | n/a | n/a | n/a | n/a | n/a |
| Nonroad gasoline equipment exhaust | -6,413 | -408,453 | 9,212 | 0.0 | 0.0 | 20.7 | 0.0 |
| Nonroad gasoline equipment evap | 6,702 | n/a | n/a | n/a | n/a | n/a | n/a |
| Nonroad gasoline equipment refueling | 563 | n/a | n/a | n/a | n/a | n/a | n/a |
| Portable fuel containers | 1,037 | n/a | n/a | n/a | n/a | n/a | n/a |
| Onroad diesel vehicles | -2,422 | -4,104 | 1,346 | -569 | -315 | 0.0 | 0.0 |

| **Table 3.2-10 continued** | **Benzene** | **Ethanol** | **1,3-Butadiene** | **Acetal-dehyde** | **Formal-dehyde** | **Naph-thalene** | **Acrolein** |
|---|---|---|---|---|---|---|---|
| Light-duty gasoline vehicle exhaust | -287 | 8,773 | 21.5 | 2,034 | 73 | 0.00 | 0.65 |
| Light-duty gasoline vehicle evap | 6.65 | 500 | n/a | n/a | n/a | 1.28 | n/a |
| Light-duty gasoline vehicle refueling | 6.63 | 770 | n/a | n/a | n/a | 0.82 | n/a |
| Heavy-duty gasoline vehicle exhaust | -47 | 57 | 0.00 | 19 | -2.11 | 0.00 | 0.00 |
| Heavy-duty gasoline vehicle evap | -1.31 | 315 | n/a | n/a | n/a | 0.09 | n/a |
| Heavy-duty gasoline vehicle refueling | 1.25 | 157 | n/a | n/a | n/a | 0.05 | n/a |
| Nonroad gasoline equipment exhaust | -737 | 2,497 | 57.4 | 189 | 54 | 0.00 | -7.95 |
| Nonroad gasoline equipment evap | 106 | 4,556 | n/a | n/a | n/a | 0.00 | n/a |
| Nonroad gasoline equipment refueling | 106 | 972 | n/a | n/a | n/a | 0.00 | n/a |
| Portable fuel containers | -0.30 | 646 | n/a | n/a | n/a | 0.13 | n/a |
| Onroad diesel vehicles | -30.08 | 0.00 | -16.48 | -66.34 | -182.09 | -0.38 | -8.82 |

[a] "VOC" values shown are actually THC for onroad gasoline exhaust and evaporative emissions.
[b] n/a = Not applicable

Table 3.2-11 shows the relative impacts of various types of renewable fuels on the basis of tons per million BTUs of renewable fuel consumed. These values include all vehicle/equipment as well as upstream fuel production/distribution impacts.

### Table 3.2-11. Emission Inventory Impacts by Type of Renewable Fuel for the Primary RFS2 Control Case Relative to the AEO 2007 Reference Case (tons per mmBTU)

| | VOC | CO | NOx | PM10 | PM2.5 | SO2 | NH3 |
|---|---|---|---|---|---|---|---|
| Ethanol from domestic corn (except coal) | 10,301 | 4,013 | 3,128 | 12,175 | 1,991 | 3,403 | 8,420 |
| Ethanol from domestic corn (coal) | 439 | 317 | 320 | 1,330 | 351 | 427 | 349 |
| Ethanol from domestic cellulosic | 10,121 | 29,888 | 32,440 | 13,168 | 2,350 | -8,377 | 15,107 |
| Ethanol from imported sugarcane | 1,717 | -830 | -2,621 | -1,116 | -418 | -1,916 | 44 |
| Biodiesel | -1,049 | 913 | -290 | 4,268 | 632 | 1,580 | 4,171 |
| Renewable Diesel | -1,602 | 23 | -26.3 | -102 | -27 | -169 | 0.0 |
| Cellulosic Diesel | -190 | 95,847 | 131,218 | 34,169 | 9,831 | 10,096 | 21,085 |

| **Table 3.2-11 continued** | **Benzene** | **Ethanol** | **1,3-Butadiene** | **Acetal-dehyde** | **Formal-dehyde** | **Naph-thalene** | **Acrolein** |
|---|---|---|---|---|---|---|---|
| Ethanol from domestic corn (except coal) | 30.1 | 10,870 | 0.097 | 335 | 67.6 | -0.617 | 141 |
| Ethanol from domestic corn (coal) | 1.2 | 451 | 0.004 | 13.8 | 2.8 | -0.026 | 5.8 |
| Ethanol from domestic cellulosic | 39.3 | 17,024 | 0.078 | 245 | 47.1 | -1.223 | 237 |
| Ethanol from imported sugarcane | 26.4 | 5,220 | -0.185 | 0.25 | -3.0 | -0.500 | 77.5 |
| Biodiesel | 10.4 | 0 | -0.188 | 1.64 | 0.77 | -0.658 | 62.6 |
| Renewable Diesel | 65.6 | 0 | 0.009 | 0.45 | 0.51 | -0.061 | 0.06 |
| Cellulosic Diesel | -0.9 | 2,299 | -0.26 | 337 | 71.0 | -2.84 | 331 |

## 3.3 Emission Inventories Used in the Air Quality Modeling

### 3.3.1 Overview of Inventory Differences

Section 3.2 above describes our latest emission inventory impacts projected to result from the increased use of renewable fuels as required by the RFS2 standards. However, the air quality modeling had to be started long before these latest emission inventory impacts could be determined. The air quality modeling presented in Section 3.4 utilized inventory impact estimates based in large part on the analysis conducted for the NPRM, but with a few enhancements. Below is an overview of the differences between these inventory impact estimates. Details of the differences between these inventories are presented in Section 3.3.2 of this RIA.

To put the differences in context, Table 3.3-1 shows the different renewable fuel volumes considered for the three analyses. This shows that the volumes used for the NPRM analysis were also the basis of the inventories used for the air quality modeling. The RFS1 reference case listed here is the RFS1 mandate case. The primary (mid-ethanol) case considered for this final rule includes much less cellulosic ethanol than in the prior analyses, but makes up for that with diesel fuel produced from cellulosic feedstocks. The final rule case that is most comparable to the RFS2 control case considered in the NPRM and air quality analyses is the high ethanol case shown in the last row of the table.

**Table 3.3-1.**
**Renewable Fuel Volumes Used in Each Analysis**
**(Bgal/year in 2022)**

| Analysis | Scenario | Ethanol | | | | Biodiesel | Renewable Diesel | Cellulosic Diesel |
|---|---|---|---|---|---|---|---|---|
| | | Corn | Cellulosic | Imported | Total | | | |
| **NPRM & AQ** | RFS1 Ref | 5.81 | 0.25 | 0.64 | 6.70 | 0.38 | 0.0 | 0.0 |
| | AEO Ref | 12.29 | 0.25 | 0.64 | 13.18 | 0.38 | 0.0 | 0.0 |
| | RFS2 | 15.0 | 16.0 | 3.14 | 34.14 | 0.81 | 0.38 | 0.0 |
| **FRM** | RFS1 Ref | 7.046 | 0.0 | 0.0 | 7.046 | 0.303 | 0.0 | 0.0 |
| | AEO Ref | 12.29 | 0.25 | 0.64 | 13.18 | 0.38 | 0.0 | 0.0 |
| | Low Ethanol | 15.0 | 0.25 | 2.24 | 17.49 | 1.67 | 0.15 | 9.26 |
| | **Mid-Ethanol (Primary)** | **15.0** | **4.92** | **2.24** | **22.16** | **1.67** | **0.15** | **6.52** |
| | High Ethanol | 15.0 | 16.0 | 2.24 | 33.24 | 1.67 | 0.15 | 0.0 |

Tables 3.3-2 and 3.3-3 summarize the differences between the US total sum of the county-level impacts used for the air quality modeling and the final rule nationwide impacts relative to the RFS1 mandate and AEO 2007 reference cases.

**Table 3.3-2.**
**Comparison of Air Quality Inventory Impacts to FRM Impacts in 2022 Relative to the RFS1 Reference Case**

| Pollutant | Air Quality Inventory Impacts | FRM Mid (Primary) Ethanol Impacts | | FRM High Ethanol Impacts | |
|---|---|---|---|---|---|
| | Annual Short Tons | Annual Short Tons | % Change vs AQ | Annual Short Tons | % Change vs AQ |
| NOx | 365,968 | 247,604 | -32% | 193,907 | -47% |
| HC | 119,873 | 100,762 | -16% | 111,581 | -7% |
| PM10 | 68,646 | 69,013 | 1% | 49,791 | -27% |
| PM2.5 | 18,199 | 15,549 | -15% | 8,834 | -51% |
| CO | -4,619,904 | -2,869,842 | 38% | -2,897,622 | 37% |
| Benzene | -9,662 | -4,264 | 56% | -4,316 | 55% |
| Ethanol | N/A[b] | 100,123 | -- | 148,345 | -- |
| 1,3-Butadiene | -194 | 224 | 216% | 224 | 216% |
| Acetaldehyde | 7,317 | 5,848 | -20% | 8,497 | 16% |
| Formaldehyde | 173 | 355 | 105% | 395 | 128% |
| Acrolein | 79 | 22 | -71% | 33 | -58% |
| SO2 | 57,380 | 3,286 | -94% | -31,836 | -155% |
| NH3 | 141 | 48,711 | 34352% | 48,709 | 34351% |

[a] Ethanol emissions for air quality modeling were generated by application of VOC speciation profiles in SMOKE, the emissions pre-processor for air quality modeling, so they were not one of the air quality inventory inputs..

## Table 3.3-3.
## Comparison of Air Quality Inventory Impacts vs FRM Impacts in 2022 Relative to the AEO 2007 Reference Case

| Pollutant | Air Quality Inventory Impacts | FRM Mid (Primary) Ethanol Impacts | | FRM High Ethanol Impacts | |
|---|---|---|---|---|---|
| | Annual Short Tons | Annual Short Tons | % Change vs AQ | Annual Short Tons | % Change vs AQ |
| NOx | 258,357 | 184,820 | -28% | 131,124 | -49% |
| HC | 38,186 | 24,523 | -36% | 35,342 | -7% |
| PM10 | 55,877 | 63,323 | 13% | 44,099 | -21% |
| PM2.5 | 17,277 | 14,393 | -17% | 7,678 | -56% |
| CO | -1,743,352 | -376,419 | 78% | -404,199 | 77% |
| Benzene | -4,094 | -1,004 | 75% | -1,056 | 74% |
| Ethanol | N/A[b] | 54,137 | -- | 102,359 | -- |
| 1,3-Butadiene | -291 | 59 | 120% | 59 | 120% |
| Acetaldehyde | 4,727 | 3,108 | -34% | 5,757 | 22% |
| Formaldehyde | -127 | 130 | 202% | 170 | 234% |
| Acrolein | 47 | 21 | -55% | 31 | -33% |
| SO2 | 15,311 | 5,065 | -67% | -30,058 | -296% |
| NH3 | 210 | 48,711 | 23065% | 48,709 | 23064% |

[a] Ethanol emissions for air quality modeling were generated by application of VOC speciation profiles in SMOKE, the emissions pre-processor for air quality modeling, so they were not one of the air quality inventory inputs..

Table 3.3-4 shows the US total emission inventories used for each of the air quality modeling cases along with the percent change from each reference case to the control case.

### Table 3.3-4.
### Air Quality Modeling Inventories and Percent Impacts in 2022

| Pollutant | US Total RFS1 | US Total AEO | US Total RFS2 | RFS2 vs RFS1 | RFS2 vs AEO |
|---|---|---|---|---|---|
| | Annual Short Tons | Annual Short Tons | Annual Short Tons | Percent Change | Percent Change |
| NOx | 11,415,147 | 11,522,759 | 11,781,115 | 3.21% | 2.24% |
| HC | 10,292,785 | 10,374,472 | 10,412,658 | 1.16% | 0.37% |
| PM10 | 11,999,983 | 12,012,752 | 12,068,629 | 0.57% | 0.47% |
| PM2.5 | 3,371,024 | 3,371,946 | 3,389,223 | 0.54% | 0.51% |
| CO | 51,631,075 | 48,754,523 | 47,011,171 | -8.95% | -3.58% |
| Benzene | 226,683 | 221,115 | 217,021 | -4.26% | -1.85% |
| Ethanol[a] | -- | -- | -- | -- | -- |
| 1,3-Butadiene | 14,458 | 14,554 | 14,264 | -1.34% | -2.00% |
| Acetaldehyde | 58,405 | 60,995 | 65,722 | 12.53% | 7.75% |
| Formaldehyde | 140,156 | 140,456 | 140,330 | 0.12% | -0.09% |
| Acrolein | 6,399 | 6,431 | 6,477 | 1.23% | 0.73% |
| SO2 | 8,878,706 | 8,920,775 | 8,936,086 | 0.65% | 0.17% |
| NH3 | 4,213,048 | 4,212,979 | 4,213,189 | 0.00% | 0.00% |

[a] Ethanol emissions were generated by application of VOC speciation profiles in SMOKE, the emissions pre-processor for air quality modeling, so they were not one of the air quality inventory inputs..

### 3.3.1.1 Major Differences Between Air Quality Modeling Inventory and Nationwide NPRM and FRM Inventories

In attempting to compare the inventory used for air quality modeling with the nationwide inventories presented in either the draft RIA of the proposed rule or this final RIA it is important to keep in mind that (a) the air quality inventories are actual estimates of total ton per year emissions for all sectors, whereas the emission inventory impacts presented in the RIA are only ton per year changes (increases or decreases) for the sectors that we consider to be affected by the rule, and (b) as described in Section 3.3.2, very different methods are used calculate the incremental upstream changes at a national level for the RIA versus the adjusted total county-level upstream inventories used for air quality modeling.

*Differences Between NPRM and Air Quality Modeling Inventories*

- The renewable fuel volumes that were considered for the NPRM and air quality modeling were the same, as shown in Table 3.3-1, but there were substantial changes in some portions of the emission inventories.

- The air quality modeling inventory used a greatly increased estimate of ethanol transport VOC and ethanol vapor losses, based on preliminary results of the ORNL analysis of ethanol transport modes and distances.[728] This is discussed in section 3.3.2.1.1 of this RIA.

- The method used to calculate the upstream portion of the air quality modeling inventory differs from the method used to calculate the estimated nationwide impacts of the rule. The main difference was for certain non-mobile source sectors where adjustment factors were applied to existing air quality modeling inventories, rather than attempting to add/subtract the absolute tons of impact within each county for each source (SCC). This difference applies mainly to agriculture, crude oil production and transport, and gasoline refining and distribution. A more detailed description of these methodological differences is provided in section 3.3.2 of this RIA.

- The downstream portion of the air quality modeling inventory was produced by running an updated version of the MOVES model at the state-month level and the NMIM model at the county-month level to generate the downstream impacts (vehicle and equipment emissions). More details are presented in Section 3.3.2.2 below.

*Differences Between Air Quality Modeling and FRM Inventories*

- The FRM inventory uses the final results of the ORNL analysis of ethanol transport modes and distances rather than the preliminary results used for the air quality modeling inventory analysis. Relative to the version used for the air quality modeling this included slightly increased truck and water transport, slightly less rail transport, and 16 percent less ethanol volume loaded into transport or storage tanks in the RFS2 control case (34 bgal ethanol), due to use of fewer total mode transfers.

- The FRM inventory also includes a substantial reduction of cellulosic biofuel plant energy requirements to account for the portion of the biomass feedstock that is not combusted for process heat.

- The FRM downstream inventory incorporates a revision of E85 effects to remove all but ethanol and acetaldehyde emission effects, due to lack of sufficient data to justify any effects on other pollutants.

- The FRM downstream inventory uses a hybrid approach, applying “more sensitive” impacts for E10 on pre-Tier 2 light duty vehicles, and applying the “less sensitive” E10 effects for Tier 2 light duty cars and trucks (meaning no impact for NOx or exhaust NMHC due to E10 for the majority of the fleet on the road in 2022).

- The FRM downstream inventory uses updated estimates of evaporative permeation impacts of E10 based on recent studies.

### 3.3.2 Detailed Explanation of Inventory Differences

This section describes how the county-level emission inventories were prepared for use in air quality modeling, and how they differ from the NPRM nationwide inventories and the final rule nationwide inventories. Air quality modeling requires much more detail and in some cases a very different method than estimation of nationwide totals. The information provided here only addresses the first step of inventory preparation for air quality modeling. The final steps involve processes like hourly allocation and certain types of temperature adjustments. Those steps, as well as application of adjustments related to the affected stationary (point and non-point) source categories, are explained in greater detail in a separate technical support document.[727]

#### 3.3.2.1 Differences in Upstream Impacts between Inventories

##### 3.3.2.1.1 Calculation of Vapor Losses During Ethanol Transport

For "upstream" emissions associated with fuel production and distribution, the largest change from the NPRM to the air quality modeling analysis was the improved estimate of VOC and ethanol vapor emissions during ethanol transport, made possible by a detailed analysis of costs and transport modes conducted by Oak Ridge National Laboratory (ORNL).[728] This change substantially increased the ethanol and VOC emissions associated with this rule.

For the NPRM analysis these emissions were estimated using a very simplified approach based on an adjustment to the gasoline transport VOC emissions to account for the much lower vapor pressure (approximately 3 psi at 100F for denatured ethanol versus 9 psi for gasoline) and molecular weight (48.7 for denatured ethanol versus approximately 72 for gasoline vapor). The net factor is 0.23 x gasoline evap VOC. Using the gasoline VOC EF of 14.94 g/mmBTU from Table 3.1-21 yields an EF of 5.20 g/mmBTU as shown in the following calculation. However, an oversight in the NPRM upstream impacts spreadsheet model resulted in use of an earlier estimate of the gasoline VOC EF of 10.2137 g/mmBTU for this ethanol calculation, which meant that the reported ethanol EF used in the NPRM was actually 3.56 g/mmBTU.

5.20 g/mmBTU of ethanol
= 0.23 x gasoline VOC per-gallon EF / ethanol energy content
= 0.23 x (14.94 g/mmBTU x 115000 BTU/gal) / 76000 BTU/gal

As mentioned in the NPRM, the main shortcoming of this methodology was that it did not account for differences between ethanol and gasoline transport modes, distances, or transfer methods in movement of the fuel from production facility to the bulk distribution terminal. For the air quality modeling analysis and final rule analysis this method was replaced using data from the ORNL analysis of projected ethanol transport modes, distances, and volumes transferred under various ethanol volume scenarios. That newer method yielded greatly increased ethanol vapor and VOC emissions. The air quality modeling analysis used preliminary results of the ORNL study, which yielded average ethanol EFs of 34.09, 36.06, and 37.94 g/mmBTU for the RFS1 reference, AEO reference, and RFS2 control cases, respectively, when averaged across all the types of tank loading.[729] For air quality modeling the detailed emission factors for each type of tank loading, shown in Table 3.3-7, were multiplied by the preliminary ORNL ktons loaded by type of tank for each county.[730,731,732]

For the FRM analysis the use of the final ORNL results yielded EFs of 26.9 - 31.7 g/mmBTU of ethanol (2.04 - 2.41 g/gal) depending on scenario, due to the added fuel transfer losses compared to pipeline-based transport of gasoline. The EF shown earlier in Table 3.1-21 (28.78 g/mmBTU) corresponds to the High Ethanol minus RFS1 reference case, and was used for calculation of VOC and ethanol vapor for all cases in this FRM analysis.

Table 3.3-5 summarizes the ethanol transport mode and volume analysis conducted by ORNL. It shows the ethanol quantities loaded into the tanks of each transport mode, which is used to calculate ethanol vapor losses during tank filling. The first three rows show the preliminary set of model results that was used to generate emission impacts for the air quality analysis. The next three rows show corrected results from the final ORNL report, which was too late to be included in the air quality modeling. These corrected results were then used as the basis for the ethanol transport emission estimates in this final rule, shown in the final three rows. Because the final rule ethanol volumes differ from the proposed rule and air quality analysis volumes, especially for the primary (mid) and low ethanol cases, we have estimated transport volumes and distances for the final rule by interpolation from the final corrected ORNL values.

**Table 3.3-5. Ethanol Transport Tank Loading Volumes in 2022**

| Source | Case | Bgal Ethanol | Kilotons Ethanol Loaded or Transferred into Each Mode[a] | | | |
|---|---|---|---|---|---|---|
| | | | Truck | Rail | Water | Local Truck |
| AQ modeled values | RFS1 | 6.69 | 3,434 | 18,565 | 2,679 | 20,952 |
| AQ modeled values | AEO | 13.18 | 6,005 | 35,555 | 3,860 | 42,915 |
| AQ modeled values | RFS2 | 34.14 | 17,012 | 76,053 | 11,959 | 133,907 |
| | | | | | | |
| Corrected FRM Basis | RFS1 | 6.69 | 3,131 | 18,565 | 2,816 | 18,431 |
| Corrected FRM Basis | AEO | 13.18 | 5,597 | 35,553 | 4,178 | 36,736 |
| Corrected FRM Basis | RFS2 | 34.14 | 17,151 | 76,023 | 11,619 | 82,460 |
| | | | | | | |
| FRM Control | Low | 17.49 | 7,973 | 43,875 | 5,708 | 46,138 |
| FRM Control | Mid | 22.16 | 10,547 | 52,892 | 7,366 | 56,326 |
| FRM Control | High | 33.24 | 16,654 | 74,285 | 11,299 | 80,496 |

[a] Includes original loading at ethanol production or import facility plus loading during transfer from another mode.

The VOC EFs shown in Table 3.3-7 are from AP-42[733] 10 psi gasoline emission rates adjusted for ethanol vapor pressure and molecular weight (net factor = 0.20 = 3 psi / 10 psi x 48.7 MW / 72 MW). In calculating the vapor losses associated with the local truck ethanol volumes, a factor of two was applied to account for the losses during both loading of the truck and loading of the retail underground storage tank from the truck.

**Table 3.3-6. SCC Assignments Used for Ethanol Tank Loading**

| SCC | SCC Description | Segments of ORNL Analysis Applied to SCC |
|---|---|---|
| 30205031 | Denatured Ethanol Storage Working Loss | All other tank loading |
| 30205052 | Ethanol Loadout to Truck | All truck loading |
| 30205053 | Ethanol Loadout to Railcar | All railcar loading |

**Table 3.3-7 Ethanol Tank Loading Vapor Emission Factors**

| ORNL Ethanol Transport Category | Description | Applied to SCC | EF (tons ethanol vapor per thousand tons ethanol) |
|---|---|---|---|
| H_Ld_Kt | Initial transport truck loading | 30205052 | 0.243 |
| R-H_Trf | Transfer from rail to truck | 30205052 | 0.243 |
| W-H_Trf | Transfer from barge to truck | 30205052 | 0.243 |
| LocTrkKt | Local distribution truck loading | 30205052 | 0.243 |
| R_Ld_Kt | Initial Railcar Loading | 30205053 | 0.243 |
| H-R_Trf | Transfer from truck to rail | 30205053 | 0.243 |
| W-R_Trf | Transfer from barge to rail | 30205053 | 0.243 |
| W_Ld_Kt | Initial barge loading | 30205031 | 0.103 |
| R-W_Trf | Transfer from railcar to barge | 30205031 | 0.103 |
| H_ULd_Kt | Unloading from transport truck to terminal tank | 30205031 | 0.222 |
| R_ULd_Kt | Unloading from rail to terminal tank | 30205031 | 0.222 |
| W_ULd_Kt | Unloading from barge to terminal tank | 30205031 | 0.222 |
| LocTrkKt | Unloading from local truck to retail tank | 30205031 | 0.222[a] |

[a] This local truck loading EF was also applied to loading the retail underground tank from the truck, using the same ethanol volume.

#### 3.3.2.1.2 Calculation of Combustion Emissions From Ethanol Transport

Table 3.3-8 summarizes the kiloton-miles transported by mode from the ORNL analysis, which is used for combustion (vehicle exhaust) emission impacts for tanker trucks, locomotives, and water (barge) transport.

**Table 3.3-8. Ethanol Transport by Mode in 2022**

| Source | Case | Bgal Ethanol | Kiloton-miles Ethanol Transport by Mode | | | |
|---|---|---|---|---|---|---|
| | | | Truck | Rail | Water | Local Truck |
| AQ modeled values | RFS1 | 6.69 | 228,831 | 18,436,891 | 1,565,254 | 138,811 |
| AQ modeled values | AEO | 13.18 | 436,498 | 30,543,455 | 2,415,480 | 268,368 |
| AQ modeled values | RFS2 | 34.14 | 1,053,071 | 49,422,639 | 3,628,079 | 695,386 |
| | | | | | | |
| Corrected FRM Basis | RFS1 | 6.69 | 290,156 | 18,630,606 | 1,498,611 | 131,712 |
| Corrected FRM Basis | AEO | 13.18 | 491,458 | 30,650,028 | 2,538,867 | 253,239 |
| Corrected FRM Basis | RFS2 | 34.14 | 1,164,335 | 47,822,752 | 3,905,640 | 534,322 |
| | | | | | | |
| FRM Control | Low | 17.49 | 629,822 | 34,181,251 | 2,819,916 | 311,038 |
| FRM Control | Mid | 22.16 | 779,742 | 38,007,426 | 3,124,441 | 373,665 |
| FRM Control | High | 33.24 | 1,135,442 | 47,085,374 | 3,846,952 | 522,253 |

### 3.3.2.1.2.1 Combustion Emissions from Rail Transport of Ethanol

The emission impacts of projected increases in rail transport of ethanol resulting from this rule were calculated by multiplying locomotive emission factors by the added ton-miles of ethanol transport. For the air quality modeling analysis and this FRM analysis we were able to make use of the ORNL projected ton-miles of rail transport of ethanol by county for each of the three cases of the air quality analysis, as summarized in Table 3.3-8. These ton-miles by county were then multiplied by the g/mmBTU EFs shown in Tables 3.1-22 and 3.1-28 along with a fuel consumption of 2.38 gallons per thousand ton-miles[FFFFFFFF] and 130,000 BTU/gallon, to determine the additional emissions by county.

For the air quality modeling these were then added to the base case (NEI 2020 projection) emissions of Class I locomotive emissions (SCC 2285002006) to obtain the county-specific emissions for the RFS1 mandate reference case, AEO reference case, and RFS2 control cases. The 2020 NEI projection values were used as the base case because they were the closest year with data readily available, and the difference between 2020 and 2022 was not considered to be important for this analysis. As described elsewhere, it was later discovered that an error had been introduced during the data handling

For the FRM analysis we used the final set of projections from ORNL, which included a 3.2 percent lesser estimate of rail transport of ethanol for the RFS2 control case compared to the values used for the air quality modeling. When put into terms of average one-way miles per trip for the nationwide upstream impacts spreadsheet, the final ORNL values yield a rail transport distance of 629 miles, compared to the 800 miles from GREET that was used for the NPRM

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[FFFFFFFF] Per 2006 American Association of Railroads, "Railroad Facts" 2007 edition, in 2006 4,214,459 gallons of diesel fuel were consumed transporting 4,214,459 million ton-miles of goods, which equates to 2.38 gallons per thousand ton-miles.

analysis. This value was calculated by dividing the 47,822,752 kton-miles by 76,023 kilotons loaded into rail tank cars in the RFS2 control (EISA) case.

###### 3.3.2.1.2.2 Combustion Emissions from Water Transport of Ethanol

Air quality modeling inventories for marine vessels using Category 3 (C3) propulsion engines (i.e., ocean-going vessels such as container ships), for calendar year 2022 were generated for a reference case and the RFS2 control case. Since ethanol imports were assumed to be zero under both RFS1 and AEO reference cases, the 2022 base case gridded inventory was used for both reference cases. The 2022 base case inventory accounts for growth and the current Tier 1 NOX controls for C3 engines and was developed using the methodology outlined in the C3 NPRM.[734]

For the RFS2 control case, the port portion of the 2022 base case inventory was adjusted to account for projected imported ethanol volumes. Gram per freight ton emission factors (EFs) by port were developed by dividing the emissions for each port by the corresponding commodity tonnage.[735] The projected imported ethanol volumes by port were then converted to tons and multiplied by the gram per freight ton EFs to determine the additional emissions by port due to imported ethanol.[736] These were then added to the 2022 base case port emissions to obtain the port-specific 2022 emissions for the RFS2 control case. The 2022 gridded inventory for the RFS2 control case air quality model run was then developed by incorporating the adjusted port inventories.

For vessels using Category 1 (C1) and Category 2 (C2) propulsion engines (i.e., harbor craft), calendar year 2022 emissions by county were calculated for the two reference cases and the RFS2 control case. The starting point was calendar year 2020 C1/C2 base case emissions by county. Given the low growth estimated for this source category and the absence of a county-level 2022 inventory, the 2020 inventory was used for this analysis. A ton per ton-mile EF for each pollutant was then developed. For the numerator, the national level tons values for 2020 were taken from the 2008 locomotive/marine FRM.[706] For the denominator, projected ton-miles for U.S. domestic shipping for 2020 was used.[737] ORNL supplied EPA with ton-miles of barge traffic by county for each of the three cases, as summarized in Table 3.3-8. For the air quality modeling the ton-miles by county were then multiplied by the tons per ton-mile EFs to determine the additional emissions by county for each case. These were then added to the base case emissions to obtain the county-specific emissions for the two reference cases and the RFS2 control case.

For the FRM analysis we used the final set of projections from ORNL, which included a 7.6 percent greater estimate of water transport of ethanol for the RFS2 control case compared to the values used for the air quality modeling. When put into terms of average one-way miles per trip for the nationwide upstream impacts spreadsheet, the final ORNL values yield a barge transport distance of 336 miles, compared to the 520 miles from GREET that was used for the NPRM analysis. This value was calculated by dividing the 3,905,640 kton-miles by 11,619 kilotons loaded into barges in the RFS2 control case.

###### 3.3.2.1.2.3 Combustion Emissions from Truck Transport of Ethanol

For the NPRM analysis we relied on the nationwide average truck transport distances assumed in GREET for transport to distribution/blending terminals (80 miles) and for local trucks distributing ethanol-gasoline blends from the terminal to the retail station (30 miles). For the air quality modeling and FRM analyses we were able to use the ORNL study described above, which supplied kton-miles of tank truck ethanol transport by county. VMT was calculated based on an average tank truck load of 52,720 lbs of ethanol. We doubled the VMT to account for return trips. Non-GHG emissions from heavy-duty diesel trucks were adjusted in the affected counties in proportion to their VMT increase. Excel versions of the ORNL data files plus calculations are available in the docket.[738]

#### 3.3.2.1.3 Calculation of Biofuel Plant Emissions

For the county-level air quality modeling emission inventories we treated the corn ethanol plants as point sources wherever possible, since most of them are either existing plants or under construction or planned with a specific location. The choice of corn/starch ethanol plant locations and capacities for the 2005 baseline air quality modeling run and each of the three 2022 cases is described in Section 1.8.1.1 of this RIA. The emissions attributed to each plant were calculated using the emission rates presented in the NPRM DRIA Table 3.1-20 multiplied by the reported or planned capacities of each plant for each of the ethanol volume scenarios.[739,740,741,742]

For the county-level air quality modeling emission inventories we treated the cellulosic biofuel plants as area sources spread across the entire area of whatever county they were considered to be located in. The choice of plant locations and capacities is described in Section 1.8.1.3 of this RIA. They were not treated as point sources because of the substantial uncertainty about where they might actually be built, and if their emissions were treated as a point source their human exposures and health impacts would have been highly dependent on proximity to urban areas. Cellulosic plant emissions were only included in the RFS2 control (EISA) case, since the production capacities of existing and planned corn ethanol plants was sufficient to meet the RFS1 reference case and AEO reference case ethanol volumes. The emission rates used for the cellulosic plants in the air quality modeling were presented in the NPRM DRIA Table 3.1-20. Those emission rates were multiplied by the assumed cellulosic ethanol plant capacities ranging from 14 - 300 million gallons per year (MGY) from forest waste, 63 - 129 MGY from corn stover, and 91 - 149 MGY from switchgrass.[743]

Biodiesel plant emissions were also treated as area sources in the air quality modeling. All three modeled cases used the same set of 35 biodiesel plants, but used different plant "capacities" (actually just different plant operation factors applied to the same total capacity). The choice of plant locations and capacities is described in Section 1.8.1.4 of this RIA. The assumed capacities for the RFS1 reference case ranged from 50,000 to 34 million gallons per year with a combined capacity of 303 MGY. The AEO reference case capacities ranged from 63,000 to 42 million gallons per year with a total capacity of 380 MGY, and the RFS2 control (EISA) case capacities ranged from 135,000 to 90 million gallons per year with a total capacity of 810 MGY. Projected emissions for each plant were calculated using the emission factors for soybean oil based biodiesel plants given in DRIA Table 3.1-20.[744,745,746]

Significant updates have been made to emissions from cellulosic plants, in part to reflect the assumed shift in volumes from cellulosic ethanol to diesel between the proposed and final rules. In addition, after the air quality modeling was done, we discovered that for cellulosic ethanol plants the calculation of emissions had been overestimated by a factor of about two due to failing to account for the portion of biomass that is not used for process energy. This change decreases the estimated NOx and CO impacts on the order of 50 percent, and shifts the PM impact from an increase to a small decrease. However, these changes are counterbalanced to varying degrees by shifting some of the cellulosic volume from ethanol to diesel, which requires nearly twice the biomass to produce one gallon of fuel. While the net effect of the changes in cellulosic plant emissions is a significant decrease in NOx and CO emissions, the shift to cellulosic diesel under the primary scenario results in a larger increase in "upstream" PM emissions than reported in the NPRM or used in the air quality modeling analysis.

#### 3.3.2.1.4 Calculation of Agricultural Emissions

The county-level agriculture-related emission inventories for air quality modeling were based on the 2002 NEI, since the NEI does not include any changes in its projections to 2022. That inventory was used for both the RFS1 and AEO reference cases. For the RFS2 control (EISA) case that inventory was modified to account for the changes in domestic agricultural activity predicted by the FASOM model, as described in Section 5.1 of the DRIA. Later modifications to the FASOM modeling that were done for the final rule analysis were not available in time for the air quality modeling. Since FASOM was only run for the AEO reference case and the RFS2 control (EISA) case, the air quality modeling did not attempt to account for any differences between the RFS1 and AEO reference cases.

The RFS2 control case agricultural emissions were estimated by applying adjustment factors shown in Table 3.3-9 to the NEI inventories for the affected source categories. The pollutants affected by these adjustments depend on the source; for example, NEI includes livestock dust for beef and dairy cattle, but not for swine or poultry. These adjustments were applied equally to all counties having any of the affected sources. This is one area of uncertainty in the inventories, since there would likely be variation from one county to another depending on how much of the predicted agricultural changes occurred in which counties. By using percent change adjustments rather than attempting to calculate absolute ton changes in each county we have attempted to minimize the inventory distortions that could occur if the calculated change for a given county was out of proportion to the reference case emissions for that county. For instance, a different approach could estimate reductions that were larger than the reference case NEI emissions, since there was no linkage between the NEI inventories and the FASOM modeling. The specific sources (SCCs) and affected pollutants that these adjustments were applied to are listed in a docket reference.[747]

**Table 3.3-9. Adjustments to Agricultural Emissions for RFS2 control Case**

| Source Description | FASOM Parameters Used (change from AEO to RFS2) | Adjustment of Air Quality inputs | Corresponding Changes in Final Ag Modeling |
|---|---|---|---|
| Nitrogen Fertilizer Application | Nitrogen fertilizer use | +2.42% | +5.73% |
| Pesticide Application | Pesticide + herbicide use | -4.56% | -0.46% |
| Pesticide Production & Transport | Pesticide + herbicide use | -4.56% | -0.46% |
| Livestock Waste | Beef+dairy cattle, swine, poultry head counts | -0.99% | -0.90% |
| Livestock Dust | Beef+dairy cattle head counts | -1.32% | -0.27% |
| Tilling/Harvesting Dust | Total acres in crop production | +0.79% | +2.65% |
| Crop Residue Burning | Total acres in crop production | +0.79% | --[a] |

[a] Crop residue burning emissions are not included as impacts in the final rule analysis.

Updates to agricultural modeling assumptions that have been made since the proposal and air quality modeling have had a significant impact on ammonia (NH3) emissions. Final modeling reflects an increase in fertilizer use with the primary control case, which results in an increase in NH3 emissions, a change from the modest decrease projected for the proposal and air quality analyses.

#### 3.3.2.1.5 Calculation of Petroleum Production Emissions

Petroleum production includes crude oil extraction and transport to refineries. For the RFS2 air quality modeling these impacts were not considered large enough relative to the other upstream impacts to attempt to model them. In our nationwide emissions analysis we assumed that (a) 75% of the change in gasoline supply was projected to come from domestic refineries, and (b) 33.1% of the change in crude being used by domestic refineries would be domestic crude. Thus, using our assumption that 1.0 gallon less of gasoline equates to approximately 1.0 gallon less crude throughput, the reduction in crude extraction and transport would equal about 25% of the change in gasoline volume. Table 3.3-10 shows what the domestic crude adjustments would have been in the air quality modeling if they had been accounted for.

**Table 3.3-10.**
**Domestic Crude Oil Volume Reductions Associated with RFS2 in 2022**

| Scenario | | Gasoline Volume Reduction (Bgal) | Domestic Crude Reduction (Bgal) |
|---|---|---|---|
| AQ Modeling | RFS2 vs RFS1 | 18.5 | 4.6 |
| | RFS2 vs AEO | 14.2 | 3.5 |
| Final Rule: High Ethanol Case | RFS2 vs RFS1 | 17.3 | 4.3 |
| | RFS2 vs AEO | 13.3 | 3.3 |
| Final Rule: Mid Ethanol Case | RFS2 vs RFS1 | 10.0 | 2.5 |
| | RFS2 vs AEO | 5.9 | 1.5 |
| Final Rule: Low Ethanol Case | RFS2 vs RFS1 | 6.9 | 1.7 |
| | RFS2 vs AEO | 2.8 | 0.7 |

#### 3.3.2.1.6 Calculation of Refinery Emissions (combustion and vapor)

For the air quality modeling of refinery emissions, adjustment factors were applied to existing NEI inventory projections for all SCCs related to refineries. These adjustments were based on ratios of crude throughput estimates from refinery modeling for each case, which varied by PADD. Different adjustment factors were applied for the AEO reference case and for the RFS2 control (EISA) case.[748] The RFS1 reference case was assumed to be the existing NEI projected inventory with no adjustments applied. Table 3.3-11 summarizes the adjustments that were used.

**Table 3.3-11.**
**Refinery Emission Adjustments for RFS2 Air Quality Modeling**

| Scenario | PADD 1 | PADD 2 | PADD 3 | PADD 4 & 5 | PADD 5 (CA) | US Total |
|---|---|---|---|---|---|---|
| AEO Reference | 0.0% | -2.5% | -1.8% | -0.4% | -0.7% | -1.5% |
| RFS2 (EISA) | 0.0% | -9.2% | -6.7% | -1.6% | -2.5% | -5.7% |

Note that this method used for estimation of county level refinery emissions is not directly comparable with the method used for nationwide impacts in the NPRM and FRM analyses, for which we used the GREET-based upstream impacts spreadsheet model to calculate the absolute change in tons for each stage of the upstream inventory.

#### 3.3.2.1.7 Calculation of Gasoline Transport, Storage and Distribution emissions: (vapor)

With the displacement of some of the gasoline pool to E10 and E85 as predicted in this analysis there would be changes in the quantity of vapor losses during the transport and distribution of gasoline and gasoline-ethanol blends. The analysis of these impacts was separated into two segments: refinery to bulk terminal (RBT) and bulk terminal to pump (BTP). The reference cases analyzed would include some amount of E0 in the BTP segment, but the ethanol volumes considered as policy options in this rule are all beyond the volume that would require E10 blends for all gasoline-fueled engines (onroad and nonroad). Thus the transport of

E0 gasoline would only occur between refineries and blending terminals in the policy cases, i.e., the RBT segment. The BTP segment would include both E10 and E85.

E0 – Refinery to Bulk Terminal (RBT)
E0 – Bulk Terminal to Pump (BTP, used for reference cases only)
E10 – Bulk Terminal to Pump (BTP)
E85 – Bulk Terminal to Pump (BTP)

For each of the above fuel type and transport stage combinations, nationwide VOC impacts (ton deltas) (and benzene and ethanol vapor) were calculated using EPA's upstream impacts spreadsheet model for each control scenario (RFS2 control vs RFS1 mandate and RFS2 control vs AEO). For air quality modeling the three BTP values were combined into a total BTP impact for each scenario. These impact values were renormalized to be ton deltas relative to the RFS1 mandate reference case, which was treated as corresponding to the NEI. Then all the SCCs in the NEI related to gasoline transport, storage, and distribution (TS&D) were categorized as either RBT or BTP, and the NEI VOC emissions were summed for each category. The nationwide VOC percent change for the AEO case relative to the RFS1 mandate reference case for RBT was calculated as the AEO case RBT delta tons (versus RFS1) divided by the NEI RBT tons. Similarly, the nationwide VOC percent change for the AEO case for BTP was calculated as the AEO case BTP delta tons (versus RFS1) divided by the NEI BTP tons. The same calculations were done for the RFS2 control case to get RBT and BTP percent changes in VOC from the RFS1 mandate case.[749]

The county level air quality inventories for the AEO and RFS2 control cases were then calculated by applying these percent changes in VOC to the corresponding sets of SCCs (point and non-point sources) for every county. The same adjustment factors were applied to benzene, which is reasonable for the VOC decrease in the refinery to bulk terminal segment. But in the terminal to pump segment benzene would be expected to decrease while VOC increases, since the VOC increaase is due to addition of ethanol to the fuel, rather than any increase in gasoline itself.

### 3.3.2.2 Differences in Downstream Impacts between Inventories

#### 3.3.2.2.1 On-Road Gasoline

In the proposal we provided two different analyses based on two different assumptions regarding the effects of E10 and E85 versus E0 on exhaust emissions from cars and trucks. Those were referred to as "less sensitive" and "more sensitive" cases. Based on analysis of recent emissions test data conducted since publication of the NPRM, we are modeling a single case. As detailed above in Section 3.2, the case modeled for the final rule is a hybrid approach, applying “more sensitive” impacts for E10 and pre-Tier 2 light duty vehicles, and applying the “less sensitive” E10 effects for Tier 2 light duty cars and trucks (meaning no impact for NOx or exhaust NMHC on the majority of light duty vehicles on the road in 2022). We have also updated our estimates of evaporative permeation impacts of E10 based on recent studies. Finally, for the final rule inventories we are only claiming emission effects with use of E85 in flex-fueled vehicles relative to E0 for two pollutants: ethanol and acetaldehyde, for which data suggests the effects are more certain. For the “more sensitive case” presented in the NPRM, and used in the air quality modeling, we had estimated changes to additional pollutants (including significant PM reductions) based on some very limited data. Until such time as additional data is collected to enhance this analysis it is premature to use such assumptions.

For the air quality inventory, EPA executed a preliminary version of MOVES dated 9/9/2008 using default database MOVESDB20080828 plus several modifications to the code and to the database. The MOVES runs produced emission factors at the state-month level for all onroad gasoline vehicles except motorcycles. Onroad gasoline inventories were generated by multiplying MOVES emission factors by VMT developed for the Office of Air Quality Planning and Standards's 2002 Version 3 Modeling Platform[750] and used in the recently published Locomotive-Marine Rule.[751] The MOBILE6 Model was M6203ChcOxFixNMIM, a special version that includes cold-start VOC and the cold-start controls of the Mobile Source Air Toxics Rule that go into effect in 2011. The NONROAD Model version was NR05d-Bond-Final, which is the same as the publically released version NONROAD2008. Both MOBILE6 and NONROAD were run using NMIM (version NMIM20071009) with NMIM County Database NCD20080724. NMIM supplied emissions from the NONROAD Model and from onroad sources not produced from MOVES. Onroad emissions generated at the state-month level from MOVES were distributed to the county-month level using the results from MOBILE6 as run by NMIM. For both NMIM and MOVES, temperatures and humidity were those of the air quality modeling base year 2005, and fuels for each case were those developed for this rule. Details of how MOVES and NMIM were configured and run are documented in a memo contained in the docket.[752]

Final rule inventories were updated using the 9/28/09 version of MOVES and database, which reflects fuel effects that are consistent with the final MOVES2010 version (baseline emission rates were still under development at this stage, so while the 9/28/09 version is updated from previous versions, results are not the same as final MOVES). Differences between the air quality modeling inventories and the NPRM and FRM inventories are due to differences in MOVES code and database versions, run granularity (national-annual vs. state-2-month vs. state-12-month), and running of the “more sensitive” case for the air quality modeling. One specific change from the NPRM version to the air quality and FRM versions was an update of reformulated gasoline properties to reflect the lower benzene levels called for by the MSAT rule, as described above in Section 3.1.1.1.

#### 3.3.2.2.2 Off-Road Gasoline

For the NPRM, emissions from nonroad gasoline equipment were developed by running the National Mobile Inventory Model (NMIM) for January and July. We limited the runs to these months to speed the analysis while also capturing the temperature extremes that can affect emissions. The NMIM County Database (NCD) used by NMIM to produce those inventories was updated as part of the 2005 National Emission Inventory (NEI) process. The NCD also included the 2005 and 2022 fuels described in Section 3.1.1.2 of the DRIA. The version of the NONROAD Model used included the effects of the 2008 Final Rule: Control of Emissions of Air Pollution from New Nonroad Spark-Ignition Engines, Equipment, and Vessels.[753] It is also capable of modeling the effects of gasoline blends containing 10 percent or less of ethanol. That version of NONROAD was later released as NONROAD2008.

For air quality modeling and the final rule analysis, NMIM was also used, but all twelve months were run.

For the NPRM, emissions from onroad and nonroad diesel equipment were also developed by running NMIM, using the same NCD and version of the NONROAD Model described above. The version of MOBILE was MOBILE6.2. Diesel fuels are less fully characterized than gasoline, since the only property used by MOBILE and NONROAD is fuel sulfur.

For the NPRM, toxic emissions for off-road reference cases were taken directly from NMIM. Inventories for the control case were developed by applying ratios of the aggregate MOVES toxic exhaust, evaporative and refueling emissions for on-road gasoline for control versus reference case, to reference case toxic emissions for off-road from NMIM.

For the air quality modeling and FRM analysis of nonroad gasoline engine emissions we used the same version of NMIM. Most toxic emissions for off-road equipment were taken directly from NMIM. The one exception was ethanol, which is not estimated by NMIM, so ethanol emissions were based on VOC speciation from light-duty gasoline vehicles. Ethanol inventories for the control case were developed by applying ratios of the aggregate MOVES ethanol exhaust, evaporative and refueling emissions for on-road gasoline for control versus reference cases, to the reference case ethanol emissions for off-road equipment.

#### 3.3.2.2.3 On-Road Diesel

For the NPRM the proposed increase in biodiesel to 0.81 billion gallons by 2022 was modeled assuming that the emission effects of biodiesel are linear with biodiesel concentration as demonstrated by Sze, et al,[754] and that impacts can be analyzed assuming all biodiesel is blended as B20. We applied the B20 effects discussed in Section 3.1.1.2.4 to baseline heavy-duty emissions generated by NMIM, as MOVES heavy-duty diesel estimates were not available in time for the NPRM analysis.

For the air quality and FRM analysis diesel emission inventories were generated using the same method as the NPRM.

#### 3.3.2.2.4 Portable Fuel Containers

The NPRM and air quality analysis used the same projected inventories for VOC, benzene, and ethanol vapor as the FRM analysis described above in Section 3.1.1.4.4.

## 3.4 Air Quality Impacts

This section presents the methodology and results of our air quality modeling to determine the projected impact of the renewable fuel volumes required by this rule on ambient concentrations of criteria and air toxic pollutants. The air quality modeling results presented here reflect the impact of increased renewable fuels use required by RFS2 compared with two different reference cases that include the use of renewable fuels: a 2022 baseline projection based on the RFS1-mandated volume of 7.1 billion gallons of renewable fuels, and a 2022 baseline projection based on the AEO 2007 volume of 13.6 billion gallons of renewable fuels. Thus, the results represent the impact of an incremental increase in ethanol and other renewable fuels. We note that the air quality modeling results presented in this final rule do not constitute the "anti-backsliding" analysis required by Clean Air Act section 211(v). EPA will be analyzing air quality impacts of increased renewable fuel use through that study and will promulgate appropriate mitigation measures under section 211(v), separate from this final action. Following the discussion of modeling results in Section 3.4, Sections 3.5 and 3.6 describe the health and environmental effects associated with the criteria and air toxic pollutants that are impacted by the required renewable fuel volumes. In addition, Section 5.4 describes the methodology for calculating monetized benefits due to reductions in adverse health effects associated with $PM_{2.5}$ and ozone.

### 3.4.1 Air Quality Modeling Methodology

Air quality models use mathematical and numerical techniques to simulate the physical and chemical processes that affect air pollutants as they disperse and react in the atmosphere. Based on inputs of meteorological data and source information, these models are designed to characterize primary pollutants that are emitted directly into the atmosphere and secondary pollutants that are formed as a result of complex chemical reactions within the atmosphere. Photochemical air quality models have become widely recognized and routinely utilized tools for regulatory analysis by assessing the effectiveness of control strategies. These models are applied at multiple spatial scales - local, regional, national, and global. This section provides detailed information on the photochemical model used for our air quality analysis (the Community Multi-scale Air Quality (CMAQ) model), atmospheric reactions and the role of chemical mechanisms in modeling, and model uncertainties and limitations. Further discussion of the modeling methodology is included in the Air Quality Modeling Technical Support Document (AQM TSD) found in the docket for this rule. Results of the air quality modeling are presented in Section 3.4.2.

#### 3.4.1.1 Modeling Methodology

A national-scale air quality modeling analysis was performed to estimate future year annual $PM_{2.5}$ concentrations, 24-hour $PM_{2.5}$ concentrations, 8-hour ozone concentrations, air toxics concentrations, and nitrogen and sulfur deposition levels for future years. The 2005-based CMAQ modeling platform was used as the basis for the air quality modeling of the two future reference cases and the RFS2 future control scenario for this final rule. This platform represents a structured system of connected modeling-related tools and data that provide a consistent and transparent basis for assessing the air quality response to projected changes in emissions. The base year of data used to construct this platform includes emissions and meteorology for 2005. The platform was developed by the U.S. EPA's Office of Air Quality Planning and Standards in collaboration with the Office of Research and Development and is intended to support a variety of regulatory and research model applications and analyses.

The CMAQ modeling system is a non-proprietary, publicly available, peer-reviewed, state-of-the-science, three-dimensional, grid-based Eulerian air quality grid model designed to estimate the formation and fate of oxidant precursors, primary and secondary PM concentrations, acid deposition, and air toxics, over regional and urban spatial scales for given input sets of meteorological conditions and emissions.[755,756,757] The CMAQ model version 4.7 was most recently peer-reviewed in February of 2009 for the U.S. EPA.[GGGGGGGG] The CMAQ model is a well-known and well-respected tool and has been used in numerous national and international applications.[758,759,760] This 2005 multi-pollutant modeling platform used the latest publicly-released CMAQ version 4.7[HHHHHHHH] with a minor internal change made by the U.S. EPA CMAQ model developers intended to speed model runtimes when only a small subset of toxics species are of interest.

CMAQ includes many science modules that simulate the emission, production, decay, deposition and transport of organic and inorganic gas-phase and particle-phase pollutants in the atmosphere. We used the most recent CMAQ version (v4.7) which was officially released by EPA's Office of Research and Development (ORD) in December 2008, and reflects updates to earlier versions in a number of areas to improve the underlying science. These include (1) enhanced secondary organic aerosol (SOA) mechanism to include chemistry of isoprene, sesquiterpene, and aged in-cloud biogenic SOA in addition to terpene; (2) improved vertical convective mixing; (3) improved heterogeneous reaction involving nitrate formation; and (4) an updated gas-phase chemistry mechanism, Carbon Bond 05 (CB05), with extensions to model explicit concentrations of air toxic species as well as chlorine and mercury. This mechanism, CB05-toxics, also computes concentrations of species that are involved in aqueous chemistry and that are precursors to aerosols. Section 3.4.1.2.2 of this RIA discusses the chemical mechanism, SOA formation and details about the improvements made to the SOA mechanism within this recent release of CMAQ.

#### 3.4.1.1.1 Model Domain and Configuration

The CMAQ modeling domain encompasses all of the lower 48 States and portions of Canada and Mexico. The modeling domain is made up of a large continental U.S. 36 kilometer (km) grid and two 12 km grids (an Eastern US and a Western US domain), as shown in Figure 3.4-1. The modeling domain contains 14 vertical layers with the top of the modeling domain at about 16,200 meters, or 100 millibars (mb).

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[GGGGGGGG] Report on the peer-review is still being finalized. Draft available upon request from Director S.T.Rao, Atmospheric Modeling and Analysis Division; rao.st@epa.gov; 919-541-4541. Allen, D., Burns, D., Chock, D., Kumar, N., Lamb, B., Moran, M. (February 2009 Draft Version). Report on the Peer Review of the Atmospheric Modeling and Analysis Division, NERL/ORD/EPA. U.S. EPA, Research Triangle Park, NC.

[HHHHHHHH] CMAQ version 4.7 was released on December, 2008. It is available from the Community Modeling and Analysis System (CMAS) as well as previous peer-review reports at: http://www.cmascenter.org.

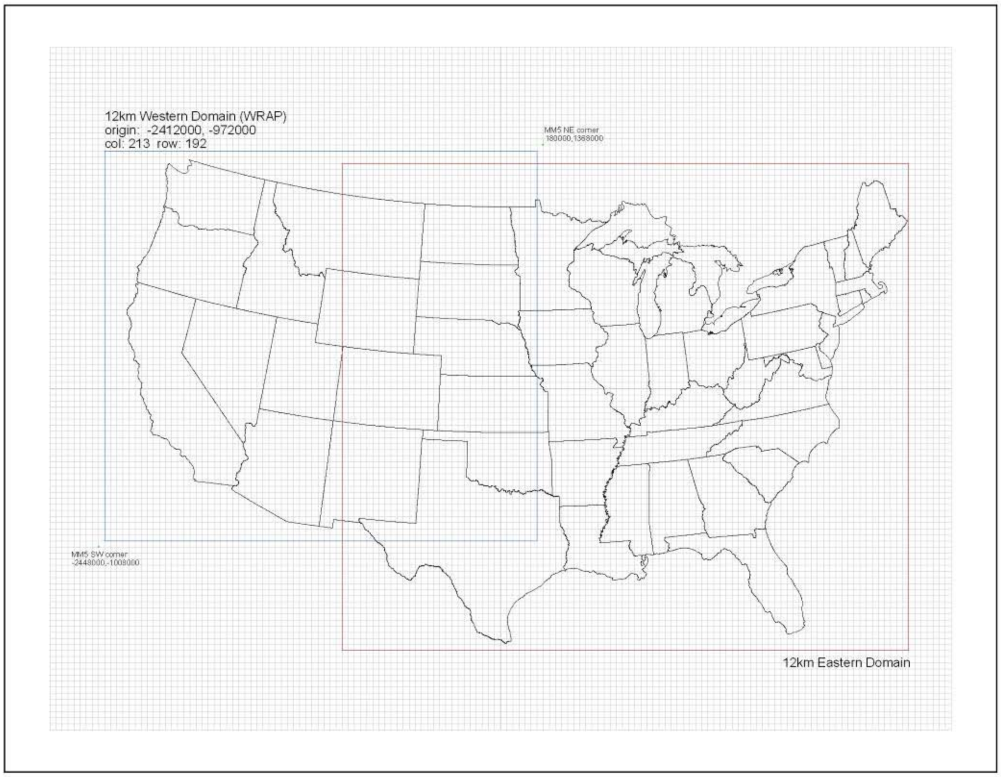

**Figure 3.4-1. Map of the CMAQ Modeling Domain**

### 3.4.1.1.2 Model Inputs

The key inputs to the CMAQ model include emissions from anthropogenic and biogenic sources, meteorological data, and initial and boundary conditions. The CMAQ meteorological input files were derived from simulations of the Pennsylvania State University/National Center for Atmospheric Research Mesoscale Model[761] for the entire year of 2005 over model domains that are slightly larger than those shown in Figure 3.4-1. This model, commonly referred to as MM5, is a limited-area, nonhydrostatic, terrain-following system that solves for the full set of physical and thermodynamic equations which govern atmospheric motions.[762] The meteorology for the national 36 km grid and the two 12 km grids were developed by EPA and are described in more detail within the AQM TSD. The meteorological outputs from MM5 were processed to create model-ready inputs for CMAQ using the Meteorology-Chemistry Interface Processor (MCIP) version 3.4, for example: horizontal wind components (i.e., speed and direction), temperature, moisture, vertical diffusion rates, and rainfall rates for each grid cell in each vertical layer.[763]

The lateral boundary and initial species concentrations are provided by a three-dimensional global atmospheric chemistry model, the GEOS-CHEM model.[764] The global GEOS-CHEM model simulates atmospheric chemical and physical processes driven by assimilated meteorological observations from the NASA's Goddard Earth Observing System (GEOS). This model was run for 2005 with a grid resolution of 2 degree x 2.5 degree (latitude-longitude) and 30 vertical layers. The predictions were used to provide one-way dynamic boundary conditions at three-hour intervals and an initial concentration field for the 36 km CMAQ simulations. The future base conditions from the 36 km coarse grid modeling were used as the initial/boundary state for all subsequent 12 km finer grid modeling.

The emissions inputs used for the 2005 base year and each of the future year base cases and control scenarios analyzed for this rule are summarized in Section 3.3 of this RIA.

#### 3.4.1.1.3 CMAQ Evaluation

An operational model performance evaluation for ozone, $PM_{2.5}$ and its related speciated components (e.g., sulfate, nitrate, elemental carbon, organic carbon, etc.), nitrate and sulfate deposition, and specific air toxics (formaldehyde, acetaldehyde, benzene, 1,3-butadiene, and acrolein) was conducted using 2005 state/local monitoring data in order to estimate the ability of the CMAQ modeling system to replicate base year concentrations. Model performance statistics were calculated for observed/predicted pairs of daily/monthly/seasonal/annual concentrations. Statistics were generated for the following geographic groupings: domain wide, Eastern vs. Western (divided along the 100th meridian), and each Regional Planning Organization (RPO) region.[IIIIIII] The "acceptability" of model performance was judged by comparing our results to those found in recent regional $PM_{2.5}$ model applications for other, non-EPA studies.[JJJJJJJ] Overall, the performance for the 2005 modeling platform is within the range or close to that of these other applications. The performance of the CMAQ modeling was evaluated over a 2005 base case. The model was able to reproduce historical concentrations of ozone and $PM_{2.5}$ over the land with low amounts of bias and error. Model predictions of annual formaldehyde, acetaldehyde and benzene showed relatively small bias and error percentages when compared to observations. The model yielded larger bias and error results for 1,3-butadiene and acrolein based on limited monitoring sites. A more detailed summary of the 2005 CMAQ model performance evaluation is available within the AQM TSD found in the docket of this rule.

#### 3.4.1.1.4 Model Simulation Scenarios

As part of our analysis for this rulemaking, the CMAQ modeling system was used to calculate daily and annual $PM_{2.5}$ concentrations, 8-hour ozone concentrations, annual and seasonal air toxics concentrations, and nitrogen and sulfur deposition total levels for each of the following emissions scenarios:

- 2005 base year

- 2022 reference case projection (RFS1 Mandate; 6.7 Bgal of ethanol, 0.38 Bgal of biodiesel. See also Table 3.3.1)

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[IIIIIII] Regional Planning Organization regions include: Mid-Atlantic/Northeast Visibility Union (MANE-VU), Midwest Regional Planning Organization – Lake Michigan Air Directors Consortium (MWRPO-LADCO), Visibility Improvement State and Tribal Association of the Southeast (VISTAS), Central States Regional Air Partnership (CENRAP), and Western Regional Air Partnership (WRAP).

[JJJJJJJ] These other modeling studies represent a wide range of modeling analyses which cover various models, model configurations, domains, years and/or episodes, chemical mechanisms, and aerosol modules.

- 2022 reference case projection (AEO 2007; 13.18 Bgal of ethanol, 0.38 Bgal of biodiesel. See also Table 3.3.1)

- 2022 control case projection (RFS2 control,; 34.14 Bgal of ethanol, 0.81 Bgal of biodiesel, 0.38 Bgal of renewable diesel. See also Table 3.3.1)

It should be noted that the emission inventories used in the air quality and benefits modeling were somewhat enhanced compared to what was described in the proposal, but due to the timing of the analysis did not include some of the later enhancements and corrections of the final emission inventories presented in this FRM. The emissions modeling TSD, found in the docket for this rule (EPA-HQ-OAR-2005-0161), contains a detailed discussion of the emissions inputs used in our air quality modeling. Section 3.3 of this RIA describes the changes in the inputs and resulting emission inventories between the preliminary assumptions used for the air quality modeling and the final regulatory scenario. These refinements, along with other inventory issues, have implications for modeling results. These implications are discussed in Sections 3.4.1.3 and 3.4.2.

We use the predictions from the model in a relative sense by combining the 2005 base-year predictions with predictions from each future-year scenario and applying these modeled ratios to ambient air quality observations to estimate daily and annual $PM_{2.5}$ concentrations, and 8-hour ozone concentrations for each of the 2022 scenarios. The ambient air quality observations are average conditions, on a site-by-site basis, for a period centered around the model base year (i.e., 2003-2007).

The projected daily and annual $PM_{2.5}$ design values were calculated using the Speciated Modeled Attainment Test (SMAT) approach. The SMAT uses a Federal Reference Method (FRM) mass construction methodology that results in reduced nitrates (relative to the amount measured by routine speciation networks), higher mass associated with sulfates (reflecting water included in FRM measurements), and a measure of organic carbonaceous mass that is derived from the difference between measured $PM_{2.5}$ and its non-carbon components. This characterization of $PM_{2.5}$ mass also reflects crustal material and other minor constituents. The resulting characterization provides a complete mass balance. It does not have any unknown mass that is sometimes presented as the difference between measured $PM_{2.5}$ mass and the characterized chemical components derived from routine speciation measurements. However, the assumption that all mass difference is organic carbon has not been validated in many areas of the U.S. The SMAT methodology uses the following $PM_{2.5}$ species components: sulfates, nitrates, ammonium, organic carbon mass, elemental carbon, crustal, water, and blank mass (a fixed value of 0.5 $\mu g/m^3$). More complete details of the SMAT procedures can be found in the report "Procedures for Estimating Future $PM_{2.5}$ Values for the CAIR Final Rule by Application of the (Revised) Speciated Modeled Attainment Test (SMAT)".[765] For this latest analysis, several datasets and techniques were updated. These changes are fully described within the technical support document for the Small SI Engine Rule modeling AQM TSD.[766] The projected 8-hour ozone design values were calculated using the approach identified in EPA's guidance on air quality modeling attainment demonstrations.[767]

Additionally, we conducted an analysis to compare the annual and seasonal, absolute and percent differences between the 2022 control case and the two 2022 reference cases for nitrate and sulfate deposition, ethanol, and five air toxics of interest (formaldehyde, acetaldehyde, benzene, 1,3-butadiene, and acrolein). These data were not compared in a relative sense due to the limited observational data available.

### 3.4.1.2 Chemical Mechanisms in Modeling

The RFS2 rule presents inventories for $NO_X$, VOC, CO, $PM_{2.5}$, $SO_2$, $NH_3$, ethanol and five air toxics: benzene, 1,3-butadiene, formaldehyde, acetaldehyde, and acrolein. Ethanol and the five air toxics are explicit model species in the CMAQv4.7 model with carbon bond 5 (CB05) mechanisms.[768] Emissions of all the pollutants included in the rule inventories, except ethanol, were generated using the Motor Vehicle Emissions Simulator (MOVES) hydrocarbon (HC) emissions and toxic-to-HC ratios calculated using MOBILE 6 (see Section 3.1.1.4.1 of the draft RIA).[769] Ethanol emissions for air quality modeling were based on speciation of VOC using different ethanol profiles (E0, E10, and E85). In addition to direct emissions, photochemical processes mechanisms are responsible for formation of some of these compounds in the atmosphere from precursor emissions. For formaldehyde and acetaldehyde, many photochemical processes are involved. CMAQ therefore also requires inventories for a large number of other air toxics and precursor pollutants. Inventories for toxic pollutants not estimated using MOVES and MOBILE6 ratios were developed by running the National Mobile Inventory Model (NMIM). Emissions of other precursor pollutants were estimated by application of speciation profiles to VOC.

In the CB05 mechanism, the chemistry of thousands of different VOCs in the atmosphere are represented by a much smaller number of model species which characterize the general behavior of a subset of chemical bond types; this condensation is necessary to allow the use of complex photochemistry in a fully 3-D air quality model.[770]

Complete combustion of ethanol in fuel produces carbon dioxide ($CO_2$) and water ($H_2O$). Incomplete combustion results in the production of other air pollutants, such as acetaldehyde and other aldehydes, and the release of unburned ethanol. Ethanol is also present in evaporative emissions. In the atmosphere, ethanol from unburned fuel and evaporative emissions can undergo photodegradation to form aldehydes (acetaldehyde and formaldehyde) and peroxyacetyl nitrate (PAN), and also plays a role in ground-level ozone formation. Mechanisms for these reactions are included in CMAQ. Additionally, other aromatic hydrocarbons (AHC) and hydrocarbons are considered because any increase in acetyl peroxy radicals due to ethanol increases might be counterbalanced by a decrease in radicals resulting from decreases in AHC and other hydrocarbons.

CMAQ includes 63 inorganic reactions to account for the cycling of all relevant oxidized nitrogen species and cycling of radicals, including the termination of $NO_2$ and formation of nitric acid ($HNO_3$) without PAN formation.[KKKKKKKK]

$NO_2 + \cdot OH + M \rightarrow HNO_3 + M$ $\quad k = 1.19 \times 10^{-11}\ cm^3 molecule^{-1} s^{-1}$ [771]

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[KKKKKKKK] All rate coefficients in this RIA are listed at 298 K and, if applicable, 1 bar of air.

The CB05 mechanism also includes more than 90 organic reactions that include alternate pathways for the formation of acetyl peroxy radical, such as by reaction of methylglyoxal, which is also formed from reactions of AHC. Alternate reactions of acetyl peroxy radical, such as oxidation of NO to form $NO_2$, which again leads to ozone formation, are also included. Atmospheric reactions and chemical mechanisms involving several key formation pathways are discussed in more detail in the following sections.

### 3.4.1.2.1 Acetaldehyde

Acetaldehyde is the main photodegradation product of ethanol, as well as other precursor hydrocarbons. Acetaldehyde is also a product of fuel combustion. In the atmosphere, acetaldehyde can react with the OH radical and $O_2$ to form the acetyl peroxy radical [$CH_3C(O)OO\cdot$].[LLLLLLLL] This radical species can then further react with nitric oxide (NO), to produce formaldehyde (HCHO), or with nitrogen dioxide ($NO_2$), to produce PAN [$CH_3C(O)OONO_2$]. An overview of these reactions and the corresponding reaction rates are provided below.[MMMMMMMM]

$\mathbf{CH_3CHO} + \cdot OH \rightarrow CH_3C\cdot O + H_2O$ $k = 1.5 \times 10^{-11}\ cm^3molecule^{-1}s^{-1}$ [772]

$CH_3C\cdot O + O_2 + M \rightarrow \mathbf{CH_3C(O)OO\cdot} + M$

$\mathbf{CH_3C(O)OO\cdot} + \boldsymbol{NO} \rightarrow CH_3C(O)O\cdot + \boldsymbol{NO_2}$ $k = 2.0 \times 10^{-11}\ cm^3molecule^{-1}s^{-1}$ [773]

$CH_3C(O)O\cdot \rightarrow \cdot CH_3 + CO_2$

$\cdot CH_3 + O_2 + M \rightarrow CH_3OO\cdot + M$

$CH_3OO\cdot + NO \rightarrow CH_3O\cdot + NO_2$

$CH_3O\cdot + O_2 \rightarrow \mathbf{HCHO} + HO_2$

$\mathbf{CH_3C(O)OO\cdot} + NO_2 + M \rightarrow \mathbf{CH_3C(O)OONO_2} + M$ $k = 1.0 \times 10^{-11}\ cm^3molecule^{-1}s^{-1}$ [774]

Acetaldehyde can also photolyze (hν), which predominantly produces $\cdot CH_3$ and HCO:

$\mathbf{CH_3CHO} + h\nu \rightarrow \cdot CH_3 + HCO$ $\lambda = 240\text{-}380\ nm$ [775]

As mentioned above, $\cdot CH_3$ is oxidized in the atmosphere to produce formaldehyde (HCHO). Formaldehyde is also a product of hydrocarbon combustion. In the atmosphere, formaldehyde undergoes photolysis and reaction with the OH radical, $NO_3$ radical, and ozone,

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[LLLLLLLL] Acetaldehyde is not the only source of acetyl peroxy radicals in the atmosphere. For example, dicarbonyl compounds (methylglyoxal, biacetyl, and others) also form acetyl radicals, which can further react to form peroxyacetyl nitrate (PAN).

[MMMMMMMM] All rate coefficients in this RIA are listed at 298 K and, if applicable, 1 bar of air.

and the resulting lifetimes are ~4 hours, 1.2 days, 83 days, and >4.5 years, respectively.[NNNNNNNN] Formaldehyde is removed mainly by photolysis whereas the higher aldehydes, those with two or more carbons such as acetaldehyde, react predominantly with OH radicals. The photolysis of formaldehyde is a source of additional radicals, and as shown above, these radicals can react with $NO_2$ to form PAN in the atmosphere.

**HCHO** + hν → H + HCO $\lambda = 240\text{-}360$ nm [776]

CB05 mechanisms for acetaldehyde formation warrant a detailed discussion given the increase in vehicle and engine exhaust emissions for this pollutant and ethanol, which can form acetaldehyde in the air. Acetaldehyde is represented explicitly in the CB05 chemical mechanism[777,778] by the ALD2 model species, which can be both formed from other VOCs and can decay via reactions with oxidants and radicals. The reaction rates for acetaldehyde, as well as for the inorganic reactions that produce and cycle radicals, and the representative reactions of other VOCs have all been updated to be consistent with recommendations in the literature.[779] The decay reactions of acetaldehyde are fewer in number and can be characterized well because they are explicit representations. Acetaldehyde can photolyze in the presence of sunlight or react with molecular oxygen ($O^3(P)$), hydroxyl radical (OH), or nitrate radicals. Of these reactions, both photolysis and reaction with OH are the most important reactions determining loss of acetaldehyde. The reaction rates are based on expert recommendations,[780] and the photolysis rate is from IUPAC recommendations.

In CMAQ v4.7, the acetaldehyde that is formed from photochemical reactions is tracked separately from that which is due to direct emission and transport of direct emissions. In CB05, there are 25 different reactions that form acetaldehyde in molar yields ranging from 0.02 (ozone reacting with lumped products from isoprene oxidation) to 2.0 (cross reaction of acylperoxy radicals, CXO3). The specific parent VOCs that contribute the most to acetaldehyde concentrations vary spatially and temporally depending on characteristics of the ambient air, but alkenes in particular are found to play a large role. The IOLE model species, which represents internal carbon-carbon double bonds, has high emissions and relatively high yields of acetaldehyde. The OLE model species, representing terminal carbon double bonds, also plays a role because it has high emissions although lower acetaldehyde yields. Production from peroxyproprional nitrate and other peroxyacylnitrates (PANX) and aldehydes with 3 or more carbon atoms also play an important role. Thus, the amount of acetaldehyde (and formaldehyde as well) formed in the ambient air as well as emitted in the exhaust (the latter being accounted for in emission inventories) is affected by changes in these precursor compounds due to the addition of ethanol to fuels (e.g., decreases in alkenes would cause some decrease of acetaldehyde, and to a larger extent, formaldehyde).

The reaction of ethanol ($CH_3CH_2OH$) with OH is slower than some other important reactions but can be an important source of acetaldehyde if the emissions are large. Based on kinetic data for molecular reactions, the only important chemical loss process for ethanol (and other alcohols) is reaction with the hydroxyl radical (·OH).[781] This reaction produces

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[NNNNNNNN] Lifetime calculated using the following: for photolysis, with overhead sun (at noontime during the summer); for OH radical reactions, a 12-hour daytime average of $2.0 \times 10^6$ molecule $cm^{-3}$; for $NO_3$ radical reactions, a 12-hour nighttime average of $5 \times 10^8$ molecule $cm^{-3}$; and for ozone, a 24-hour average of $7 \times 10^{11}$ molecule $cm^{-3}$.

acetaldehyde ($CH_3CHO$) with a 90% yield.[782] The lifetime of ethanol in the atmosphere can be calculated from the rate coefficient, k, and due to reaction with the OH radical, occurs on the order of a day in polluted urban areas or several days in unpolluted areas.[OOOOOOOO]

$\mathbf{CH_3CH_2OH} + \cdot OH \rightarrow CH_3C\cdot HOH + H_2O \qquad k = 3.2 \times 10^{-12}\ cm^3 molecule^{-1}s^{-1}$ [783]

$CH_3C\cdot HOH + O_2 \rightarrow \mathbf{CH_3CHO} + HO_2$

In CB05, reaction of one molecule of ethanol yields 0.90 molecules of acetaldehyde. It assumes the majority of the reaction occurs through H-atom abstraction of the more weakly-bonded methylene group, which reacts with oxygen to form acetaldehyde and hydroperoxy radical (HO2), and the remainder of the reaction occurs at the –CH3 and -OH groups, creating formaldehyde (HCHO), oxidizing NO to NO2 (represented by model species XO2) and creating glycoaldehyde, which is represented as ALDX:

CH3CHOH + OH → HO2 + 0.90 CH3CHO + 0.05 ALDX + 0.10 HCHO + 0.10 XO2

### 3.4.1.2.2 Secondary Organic Aerosols (SOA)

Secondary organic aerosol (SOA) chemistry research described below has led to implementation of new pathways for secondary organic aerosol (SOA) in CMAQ 4.7, based on recommendations of Edney et al. and the recent work of Carlton et al.[784, 785] In previous versions of the CMAQ model, all SOA was treated as semi-volatile, whereas in CMAQ v4.7, non-volatile SOA are simulated as well, including SOA originating from aromatic oxidation under low-$NO_x$ conditions.

#### 3.4.1.2.2.1 SOA Research

SOA results when products of atmospheric transformation or photooxidation of a volatile organic compound (VOC) form or partition to the particle phase. Current research suggests SOA contributes significantly to ambient organic aerosol (OA) concentrations, and in Southeast and Midwest States may make up more than 50% (although the contribution varies from area to area) of the organic fraction of $PM_{2.5}$ during the summer (but less in the winter).[786,787] A wide range of laboratory studies conducted over the past twenty years show that anthropogenic aromatic hydrocarbons and long-chained alkanes, along with biogenic isoprene, monoterpenes, and sesquiterpenes, contribute to SOA formation.[788,789,790,791,792] Anthropogenic SOA is a small portion of all SOA; most is biogenic and varies with season. Based on these laboratory results, SOA chemical mechanisms have been developed and integrated into air quality models such as the CMAQ model and have been used to predict OA concentrations.[793]

Over the past 10 years, ambient OA concentrations have been routinely measured in the U.S. and some of these data have been used to determine, by employing source/receptor methods, the contributions of the major OA sources, including biomass burning and vehicular gasoline and diesel exhaust. Since mobile sources are a significant source of VOC emissions, currently accounting for approximately 50% of anthropogenic VOC,[794] mobile sources are also

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[OOOOOOOO] All rate coefficients in this RIA are listed at 298 K and, if applicable, 1 bar of air.

an important source of SOA.

Toluene is an important contributor to anthropogenic SOA. Other aromatic compounds contribute as well, but the extent of their contribution has not yet been quantified. Mobile sources are the most significant contributor to ambient toluene concentrations as shown by analyses done for the 2002 National Air Toxics Assessment (NATA)[795] and the Mobile Source Air Toxics (MSAT) Rule.[796] 2002 NATA indicates that onroad and nonroad mobile sources accounted for 70% (2.24 µg/m$^3$) of the total average nationwide ambient concentration of toluene (3.24 µg/m$^3$), when the contribution of the estimated "background" is apportioned among source sectors.

The amount of toluene in gasoline influences the amount of toluene emitted in vehicle exhaust and evaporative emissions, although, like benzene, some toluene is formed in the combustion process. In turn, levels of toluene and other aromatics in gasoline are potentially influenced by the amount of ethanol blended into the fuel. Due to the high octane quality of ethanol, it greatly reduces the need for and levels of other high-octane components such as aromatics including toluene (which is the major aromatic compound in gasoline). Since toluene contributes to SOA and the toluene level of gasoline is decreasing, it is important to assess the effect of these reductions on ambient PM.

It is unlikely that ethanol would directly form SOA or affect SOA formation indirectly through changes in the radical populations from increasing ethanol exhausts. Nevertheless, scientists at the U.S. EPA's Office of Research and Development's National Exposure Research Laboratory recently directed experiments to investigate ethanol's SOA forming potential.[797] The experiments were conducted under conditions where peroxy radical reactions would predominate (irradiations performed in the absence of NOx and OH produced from the photolysis of hydrogen peroxide). This was the most likely scenario under which SOA formation could occur, since a highly oxygenated C4 organic would be potentially made. As expected, no SOA was produced. From these experiments, the upper limit for the aerosol yield would have been less than 0.01% based on scanning mobility particle sizer (SMPS) data. Given the expected negative result based on these initial smog chamber experiments, these data were not published.

In general, a review of the literature shows limited data on SOA concentrations, largely due to the lack of analytical methods for identifying and determining the concentrations of the highly polar organic compounds that make up SOA. The most widely applied method of estimating total ambient SOA concentrations is the EC tracer method using ambient data which estimates of the OC/EC ratio in primary source emissions.[798,799] SOA concentrations have also been estimated using OM (organic mass) to OC (organic carbon) ratios, which can indicate that SOA formation has occurred, or by subtracting the source/receptor-based total primary organic aerosol (POA) from the measured OC concentration.[800] Such methods, however, may not be quantitatively accurate and provide no information on the contribution of individual biogenic and anthropogenic SOA sources, which is critical information needed to assess the impact of specific sources and the associated health risk. These methods assume that OM containing additional mass from oxidation of OC comes about largely (or solely) from SOA formation. In particular, the contributions of anthropogenic SOA sources, including those of aromatic precursors, are required to determine exposures and risks associated with replacing fossil fuels with biofuels.

Upon release into the atmosphere, numerous VOC compounds can react with free radicals in the atmosphere to form SOA. While this has been investigated in the laboratory, there is relatively little information available on the specific chemical composition of SOA compounds themselves from specific VOC precursors. This absence of compositional data from the precursors has largely prevented the identification of aromatically-derived SOA in ambient samples which, in turn, has prevented observation-based measurements of the aromatic and other SOA contributions to ambient PM levels.

As a first step in determining the ambient SOA concentrations, EPA has developed a tracer-based method to estimate such concentrations.[801,802] The method is based on using mass fractions of SOA tracer compounds, measured in smog chamber-generated SOA samples, to convert ambient concentrations of SOA tracer compounds to ambient SOA concentrations. This method consists of irradiating the SOA precursor of interest in a smog chamber in the presence of $NO_x$, collecting the SOA produced on filters, and then analyzing the samples for highly polar compounds using advanced analytical chemistry methods. Employing this method, candidate tracers have been identified for several VOC compounds which are emitted in significant quantities and known to produce SOA in the atmosphere. Some of these SOA-forming compounds include toluene, a variety of monoterpenes, isoprene, and β-caryophyllene, the latter three of which are emitted by vegetation and are more significant sources of SOA than toluene. Smog chamber work can also be used to investigate SOA chemical formation mechanisms.[803,804,805,806]

Although these concentrations are only estimates, due to the assumption that the mass fractions of the smog chamber SOA samples using these tracers are equal to those in the ambient atmosphere, there are presently no other means available for estimating the SOA concentrations originating from individual SOA precursors. Among the tracer compounds observed in ambient $PM_{2.5}$ samples are two tracer compounds that have been identified in smog chamber aromatic SOA samples.[807] To date, these aromatic tracer compounds have been identified, in the laboratory, for toluene and *m*-xylene SOA. Additional work is underway by the EPA to determine whether these tracers are also formed by benzene and other alkylbenzenes (including *o*-xylene, *p*-xylene, 1,2,4-trimethylbenzene, and ethylbenzene).

One caveat regarding this work is that a large number of VOCs emitted into the atmosphere, which have the potential to form SOA, have not yet been studied in this way. It is possible that these unstudied compounds produce SOA species which are being used as tracers for other VOCs. This means that the present work could overestimate the amount of SOA formed in the atmosphere by the VOCs studied to date. This approach may also estimate entire hydrocarbon classes (e.g., all methylsubstituted-monoaromatics or all monoterpenes) and not individual precursor hydrocarbons. Thus the tracers could be broadly representative and not indicative of individual precursors. This is still unknown. Also, anthropogenic precursors play a role in formation of atmospheric radicals and aerosol acidity, and these factors influence SOA formation from biogenic hydrocarbons. This anthropogenic and biogenic interaction, important to EPA and others, needs further study. The issue of SOA formation from aromatic precursors is an important one to which EPA and others are paying significant attention. For benzene, smog chamber studies show that benzene forms SOA possibly through reactions with $NO_x$. Early smog chamber work suggests benzene might be relatively inert in forming SOA, although this study may not be conclusive.[808] However, more recent work shows that benzene does form SOA in smog chambers.[809,810] This new smog chamber work shows that benzene can be oxidized in the presence of $NO_x$ to form SOA with maximum mass of SOA being 8-25% of the mass of benzene. As mentioned above, work is needed to determine if a tracer compound can be found for benzene SOA which might indicate how much of ambient SOA comes from benzene.

The aromatic tracer compounds and their mass fractions have also been used to estimate monthly ambient aromatic SOA concentrations from March 2004 to February 2005 in five U.S. Midwestern cities.[811] The annual tracer-based SOA concentration estimates were 0.15, 0.18, 0.13, 0.15, and 0.19 μg carbon/$m^3$ for Bondville, IL, East St. Louis, IL, Northbrook, IL, Cincinnati, OH and Detroit, MI, respectively, with the highest concentrations occurring in the summer. On average, the aromatic SOA concentrations made up 17 % of the total SOA concentration. Thus, this work suggests that we are finding ambient PM levels on an annual basis of about 0.15 μg/$m^3$ associated with present toluene levels in the ambient air in these Midwest cities. Based on preliminary analysis of recent laboratory experiments, it appears the toluene tracer could also be formed during photooxidation of some of the xylenes.[812]

Over the past decade a variety of modeling studies have been conducted to predict ambient SOA levels, with most studies focusing on the contributions of biogenic monoterpenes and anthropogenic aromatic hydrocarbons. More recently, modelers have begun to include the contribution of the isoprene SOA to ambient OC concentrations.[813] In general, the studies have been limited to comparing the sum of the POA and SOA concentrations with ambient OC concentrations. The general consensus in the atmospheric chemistry community appears to be that monoterpene contributions, which are clearly significant, and the somewhat smaller aromatic contributions, are insufficient to account for observed ambient SOA levels.[814] Part of this gap has been filled recently by SOA predictions for isoprene. Furthermore, the identification in ambient SOA of a tracer compound for the sesquiterpene β-caryophyllene,[815] coupled with the high sesquiterpene SOA yields measured in the laboratory,[816] suggests this class of hydrocarbons should be included in SOA chemical mechanisms. In addition, recent data on SOA formation from aromatic hydrocarbons suggest their contributions, while much smaller than biogenic hydrocarbons, could be larger than previously thought.[817,818]

#### 3.4.1.2.3 Ozone

As mentioned above, the addition of ethanol to fuels has been shown to contribute to PAN formation and this is one way for it to contribute therefore to ground-level ozone formation. PAN is a reservoir and carrier of $NO_x$ and is the product of acetyl radicals reacting with $NO_2$ in the atmosphere. One source of PAN is the photooxidation of acetaldehyde (Section 3.4.1.2.1), but any hydrocarbon having a methyl group has the potential for forming acetyl radicals and therefore PAN.[PPPPPPPP] PAN can undergo thermal decomposition with a lifetime of approximately 1 hour at 298K or 148 days at 250K.[QQQQQQQQ]

$\mathbf{CH_3C(O)OONO_2} + M \rightarrow CH_3C(O)OO\cdot + \mathbf{NO_2} + M \qquad k = 3.3 \times 10^{-4}\ s^{-1}$ [819]

The reaction above shows how $NO_2$ is released in the thermal decomposition of PAN. $NO_2$ can also be formed in photodegradation reactions where NO is converted to $NO_2$ (see OH radical reaction of acetaldehyde in Section 3.4.1.2.1). In both cases, $NO_2$ further photolyzes to produce ozone ($O_3$).

$\mathbf{NO_2} + h\nu \rightarrow NO + O(^3P) \qquad \lambda = 300\text{-}800\ nm$ [820]

$O(^3P) + O_2 + M \rightarrow \mathbf{O_3} + M$

The temperature sensitivity of PAN allows it to be stable enough at low temperatures to be transported long distances before decomposing to release $NO_2$. $NO_2$ can then participate in ozone formation in regions remote from the original $NO_x$ source.[821] A discussion of CB05 mechanisms for ozone formation can be found in Yarwood et al. (2005).[822]

### 3.4.1.3 Modeling Uncertainties and Limitations

All the results presented below must be interpreted with the understanding that there are considerable uncertainties in inventories, atmospheric processes in CMAQ, and other aspects of the modeling process. While it is beyond the scope of this Regulatory Impact Analysis to include a comprehensive discussion of all limitations and uncertainties associated with air quality modeling, the key ones which could significantly impact analyses for this rule are addressed.

#### 3.4.1.3.1 Emission Inventory Limitations

A key limitation of the analysis is that it employed interim emission inventories, which were enhanced compared to what was described in the proposal, but did not include some of the later enhancements and corrections of the final emission inventories presented in this FRM (Section 3.3). Most significantly, our modeling of the air quality impacts of the renewable fuel volumes required by RFS2 relied upon interim inventories that assumed that ethanol will make up 34 of the 36 billion gallon renewable fuel mandate, that approximately 20 billion gallons of this ethanol will be in the form of E85, and that the use of E85 results in fewer emissions of direct $PM_{2.5}$ from vehicles. The emission impacts and air quality results would be different if, instead of E85, more non-ethanol biofuels are used or mid-level ethanol blends are approved.

In fact, as explained in Chapter 1 of the RIA, our more recent analyses indicate that ethanol and E85 volumes are likely to be significantly lower than what we assumed in the

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[PPPPPPPP] Many aromatic hydrocarbons, particularly those present in high percentages in gasoline (toluene, m-, o-, p-xylene, and 1,3,5-, 1,2,4-trimethylbenzene), form methylglyoxal and biacetyl, which are also strong generators of acetyl radicals (Smith, D.F., T.E. Kleindienst, C.D. McIver (1999) Primary product distribution from the reaction of OH with m-, p-xylene and 1,2,4- and 1,3,5-Trimethylbenzene. J. Atmos. Chem., 34: 339- 364.).

[QQQQQQQQ] All rate coefficients in this RIA are listed at 298 K and, if applicable, 1 bar of air.

interim inventories. Furthermore, the final emission inventories do not include vehicle-related PM reductions associated with E85 use, as discussed in Section 3.1 and 3.3 above. There are additional, important limitations and uncertainties associated with the interim inventories that must be kept in mind when considering the results:

- Error in $PM_{2.5}$ emissions from locomotive engines

  After the air quality modeling was completed, we discovered an error in the way that $PM_{2.5}$ emissions from locomotive engines were allocated to counties in the inventory. Locomotive emissions between the two reference cases and the control case vary due to differences in activity for this sector due to transported volumes of ethanol. To account for these differences, adjustments were to be applied to a common base inventory developed for a 2022 projection of the 2005 air quality modeling platform (http://www.epa.gov/ttn/chief/emch/index.html). The result should have been inventories which reflected county emissions given the RFS1, AEO 2007 and RFS2 fuel volumes. However, in processing the data, errors were introduced which led to inconsistencies in the common base inventory used to develop the PM inventories for the three modeling cases. These errors were random, resulting in PM emission changes that were too high in some counties and too low in other counties. This error had very little impact on national-level $PM_{2.5}$ emissions. The error in locomotive $PM_{2.5}$ inventory impacts for the RFS2 control case versus the RFS1 mandate reference case was 111 tons, out of a total $PM_{2.5}$ inventory impact of about 18,000 tons. The error in the impact of the RFS2 control case versus the AEO 2007 reference case was 1377 tons, out of a total $PM_{2.5}$ inventory impact of about 16,000 tons. It is important to note that the total nationwide $PM_{2.5}$ inventory is projected to be over 3.3 million tons in 2022. However, an analysis of the error indicated local impacts in both cases were quite large, and in a number of locations, dominated $PM_{2.5}$ impacts. These impacts are summarized in a memorandum to the docket.[RRRRRRRR] As a result of the error, we do not present the modeling results for specific localized $PM_{2.5}$ impacts. However, we have concluded that $PM_{2.5}$ modeling results are still informative for national-level benefits assessment, as described in Section 5.4 of the RIA.

- Sensitivity of light-duty vehicle exhaust emissions to ethanol blends

  As discussed above in Sections 3.1 and 3.3, the interim emission inventories used for the air quality modeling analysis are the "more sensitive" case described in the proposal. As a result, the interim inventories used for air quality modeling assume that vehicles operating on E10 have higher NOx emissions and lower VOC, CO and PM exhaust emissions compared to the FRM inventories.

- Cellulosic plant emissions

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[RRRRRRRR] Memorandum from Rich Cook to Docket ID No. EPA-HQ-OAR-2005-0161, "Impact of an Error in the Locomotive Particulate Matter (PM2.5) Inventory on RFS2 Modeling Results."

The interim emission inventories used in air quality modeling generally assumed higher emissions from cellulosic plants than the FRM inventories, which used revised estimates based on updates to the fraction of biomass burned at these plants. However, as noted in Section 3.1 and 3.3, the shift of some cellulosic volume from ethanol to diesel results in higher PM emissions from cellulosic plants in the final rule inventories than used in the air quality modeling inventories.

- Ethanol volume

  As mentioned above, the interim emission inventories used in our air quality modeling reflect the use of ethanol in about 34 of the mandated 36 billion gallons and do not include any cellulosic diesel. As shown in Table VI.A-1 of the preamble, the FRM inventories assume 22 billion gallons of ethanol in the primary case and 6.5 billion gallons of cellulosic diesel. The inventories used for air quality modeling assume ethanol volumes are more consistent with the FRM's high-ethanol case inventory, which reflects the use of 33 billion gallons of ethanol and no cellulosic diesel.

- Renewable fuel transport emissions

  As discussed in Section 3.3, the estimates of renewable fuel transport volumes and distances differ between the air quality modeling and final rule inventories.

There are also some important uncertainties associated with the emissions inventories, apart from the differences between the interim inventories and the FRM inventories. For example, E85 exhaust and evaporative emissions data are limited, as are data on E10 exhaust and evaporative emissions for nonroad spark ignition engines. There is also considerable uncertainty in how increased use of ethanol will impact other fuel properties which can affect emission inventories and air quality. There are also limited data on activity and emission rates for key upstream sources (especially future technology corn ethanol plants and cellulosic ethanol and diesel plants). There are uncertainties in the surrogates used to allocate emissions spatially and temporally; this is particularly significant in projecting the location of new ethanol plants, especially future cellulosic biofuel plants and the location of these emissions. These plants can have large impacts on local emissions. While most increased production of corn ethanol can reasonably be assumed to occur at existing or planned facilities, there is no way to know with certainty where cellulosic biofuel production will occur. Future cellulosic biofuel plant siting was based on the types of feedstocks that would be most economical, and we assumed refineries would be located in close proximity to feedstocks, as discussed in Section 1.8 of the RIA. While corn ethanol plants were treated as point sources, cellulosic biofuel plants were modeled as county-wide area sources, as described in Section 1.8. Finally, there are numerous assumptions about land use changes that impact inventories for upstream sources and consequently can impact air quality modeling results.

###### 3.4.1.3.2 Uncertainties in Hydrocarbon Speciation Profiles

Another source of uncertainty involves the hydrocarbon speciation profiles, which are used in the air quality modeling emission pre-processor, SMOKE, to break total hydrocarbons down into individual constituent compounds. Given the complexity of the atmospheric chemistry, the hydrocarbon speciation has an important influence on the air quality modeling results. For example, we found that adjusting the speciation profile for gasoline headspace emissions changed the ambient concentration of acetaldehyde. SMOKE uses gasoline headspace profiles for E0 and E10 from EPA's SPECIATE database to speciate emissions from gasoline storage, gasoline distribution, and gas cans. These are key sources of upstream emissions affected by increased use of E10. The EPA profiles initially used in the reference case scenarios for gasoline headspace emissions (i.e., emissions from gas cans and tanker truck distribution – profiles 8736 and 8737 for E10 and E0) in EPA's SPECIATE4.2 database show much greater differences in alkene (olefin) compounds than one would expect between E0 and E10. Alkenes react in the atmosphere to form secondary acetaldehyde, and can also form ozone. E0 has 13% of the VOC (volatile organic compounds) as alkenes while the E10 profile has only 4% alkenes. By contrast, the profiles for exhaust from Tier 2 vehicles (8756 and 8757 for E0 and E10 respectively) show similar levels of alkenes for E0 and E10 (about 20%).[823] The evaporative emissions profiles (profiles 8753 and 8754 in EPA's SPECIATE4.2 database[824]) show lower olefin contents of 3% and 6% respectively.

One expects the headspace from E10 blends to have similar olefin content to that from E0 blends. Available data indicate that ethanol forms an azeotrope with various hydrocarbon compounds such as olefins.[825,826] That azeotrope for olefins would result in the partial vapor pressure of the olefins in the E10 blends being about the same or somewhat higher than in an E0 blends. The difference between the E0 and E10 profile is likely because the limited fuel samples taken for headspace analysis were taken in different locations and time periods.
Recent measurements of speciated gasoline headspace vapors were collected by EPA's Office of Research and Development (ORD) to compare differences between an E0 fuel and a splash-blended E10.[827] The addition of 10% ethanol to the base E0 fuel only slightly decreased the olefin content from 7.6% to 6.3% of total VOC observed in the headspace vapors. While there is some uncertainty in representativeness of the splash-blended fuel, a follow-up analysis of speciated headspace vapors from in-use E10 gasolines showed significant variation in olefin composition from one fuel to another, illustrating the need for speciation profiles collected under controlled conditions.[828]

Because the E0 and E10 headspace profiles initially used in the reference case scenarios have an uncharacteristic difference in relative alkene levels, EPA reran the control case using an adjusted E0 gasoline headspace profile.[ssssssss] However, due to time constraints, EPA did not rerun the two reference cases with the adjusted E0 profile, resulting in an inconsistency between the control case and the reference cases. Implications of this inconsistency are discussed in Section 3.4.2. EPA believes that it is important to correct the gasoline headspace profile, although we recognize that using an adjusted profile introduces inconsistencies between the reference and control cases. It should be noted that this is but one example of potential weaknesses in the emission speciation data. Profiles for a number of key sources are based on data with significant limitations.

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[ssssssss] Use of the adjusted profile in the control case rerun is discussed in the emissions modeling TSD, found in the docket for this rule (EPA-HQ-OAR-2005-0161).

#### 3.4.1.3.3 Uncertainties Associated with Chemical Mechanisms

Another key source of uncertainty is the photochemical mechanisms in CMAQ 4.7. Pollutants such as ozone, PM, acetaldehyde, formaldehyde, acrolein, and 1,3-butadiene can be formed secondarily through atmospheric chemical processes. Since secondarily formed pollutants can result from many different reaction pathways, there are uncertainties associated with each pathway. Simplifications of chemistry must be made in order to handle reactions of thousands of chemicals in the atmosphere. Mechanisms for formation of ozone, PM, acetaldehyde and peroxyacetyl nitrate (PAN) are particularly relevant for this rule, and are discussed in Section 3.4.1.2.

For PM, there are a number of uncertainties associated with SOA formation that should be addressed explicitly. As mentioned in Section 3.4.1.2.2, a large number of VOCs emitted into the atmosphere, which have the potential to form SOA, have not yet been studied in detail. In addition, the amount of ambient SOA that comes from benzene is uncertain. Simplifications to the SOA treatment in CMAQ have also been made in order to preserve computational efficiency. These simplifications are described in release notes for CMAQ 4.7 on the Community Modeling and Analysis System (CMAS) website.[829]

### 3.4.2 Air Quality Modeling Results

As described above, we performed a series of air quality modeling simulations for the continental U.S in order to assess the impacts of the renewable fuel volumes required by RFS2. The results presented here are based on inventory projections for RFS2 compared against the AEO 2007 and RFS1 mandate reference cases, both of which include some usage of ethanol fuels. These results are important for understanding the potential differences between RFS2 volumes of ethanol and AEO 2007 or RFS1 mandate reference cases; however, these results do not constitute the “anti-backsliding” analysis required by Clean Air Act section 211(v). EPA will be analyzing air quality impacts of increased renewable fuel use through that study and will promulgate appropriate mitigation measures under section 211(v), separate from this final action. Notably, the anti-backsliding exercise will be able to include inventory improvements based on additional results from the EPAct test program which we could not include in this analysis due to time restraints.[830] The following results are based on the interim inventories detailed in Section 3.3 and subject to the uncertainties and limitation detailed in Section 3.4.1.3.

#### 3.4.2.1 Current and Projected Ambient Levels of Pollutants

Although the purpose of this final rule is to implement the renewable fuel requirements established by the Energy Independence and Security Act (EISA) of 2007, the renewable fuel volumes required by this rule would also impact emissions of criteria and air toxic pollutants and their resultant ambient concentrations. The fuels changes detailed in Section 3.1 of the RIA will influence emissions of VOCs, PM, $NO_X$, $SO_X$, CO and air toxics. Air quality modeling performed for this final rule illustrates the changes in ambient concentrations of $PM_{2.5}$ and ozone as well as changes in ambient concentrations of ethanol and the following air toxics: acetaldehyde, acrolein, benzene, 1,3-butadiene, and formaldehyde. These changes are expected to occur with emissions changes from the renewable fuel volumes required by RFS2. The air quality modeling results also include changes in deposition of nitrogen and sulfur which are expected to occur with emissions changes from the renewable fuel volumes required by RFS2.

This section describes current ambient levels of ozone, PM, air toxics, and nitrogen and sulfur deposition and presents the projected ambient levels resulting from the increased use of renewable fuels. Note that the projected results for PM are impacted by the error in the $PM_{2.5}$ locomotive inventory (Section 3.4.1.3) and therefore we do not present the modeling results for specific localized $PM_{2.5}$ impacts.

#### 3.4.2.1.1 Particulate Matter ($PM_{2.5}$ and $PM_{10}$)

As described in Section 3.5, PM causes adverse health effects, and the EPA has set national ambient air quality standards (NAAQS) to protect against those health effects. In this section we present information on current and model-projected future PM levels.

##### 3.4.2.1.1.1 Current Levels of PM

Figures 3.4-2 and 3.4-3 show a snapshot of annual and 24-hour $PM_{2.5}$ concentrations in 2007. There are two U.S. National Ambient Air Quality Standards (NAAQS) for $PM_{2.5}$: an annual standard (15 $\mu g/m^3$) and a 24-hour standard (35 $\mu g/m^3$). In 2007, the highest annual average $PM_{2.5}$ concentrations were in California, Arizona, Alabama, and Pennsylvania and the highest 24-hour $PM_{2.5}$ concentrations were in California, Idaho, and Utah.

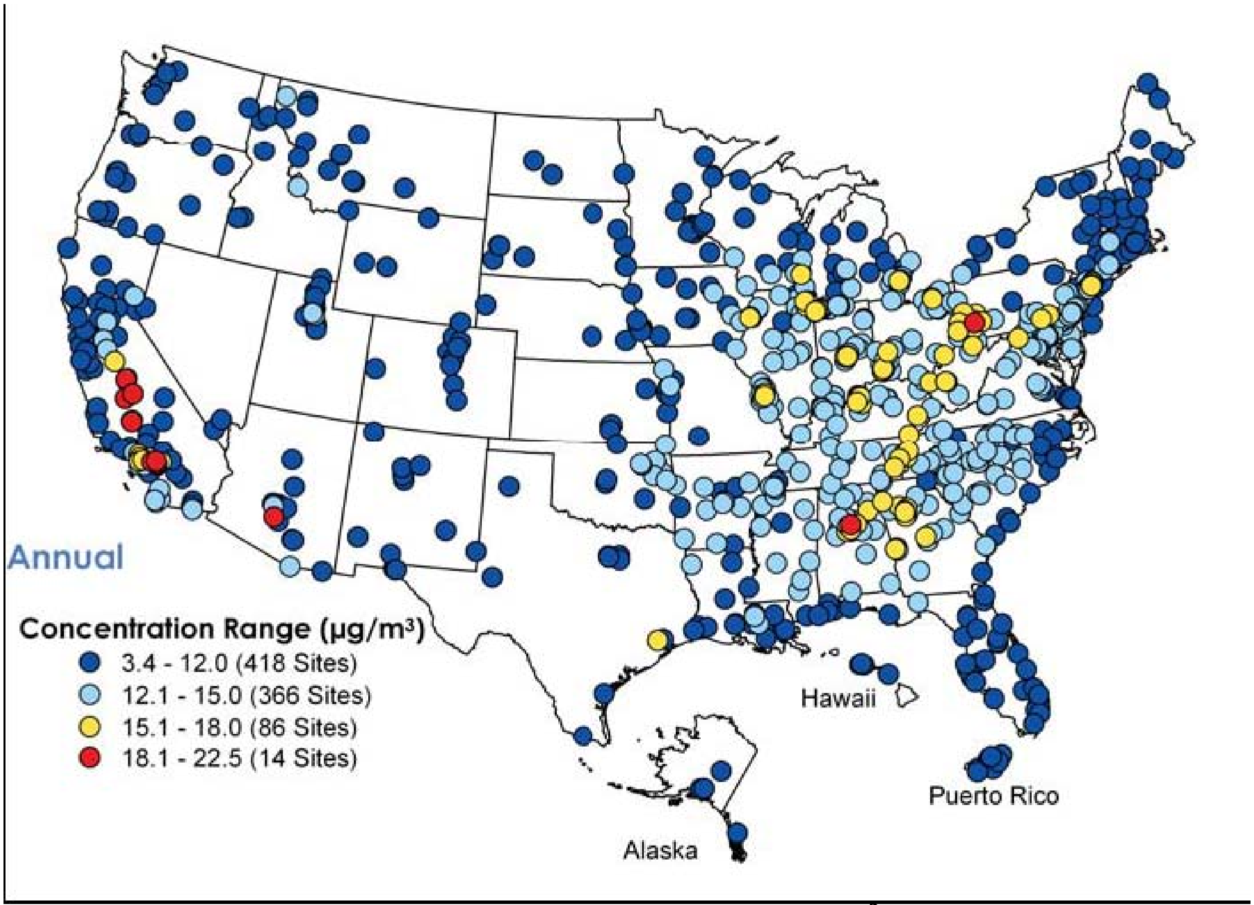

**Figure 3.4-2. Annual Average $PM_{2.5}$ Concentrations in µg/m$^3$ for 2007 (from 2008 Air Trends Report)**

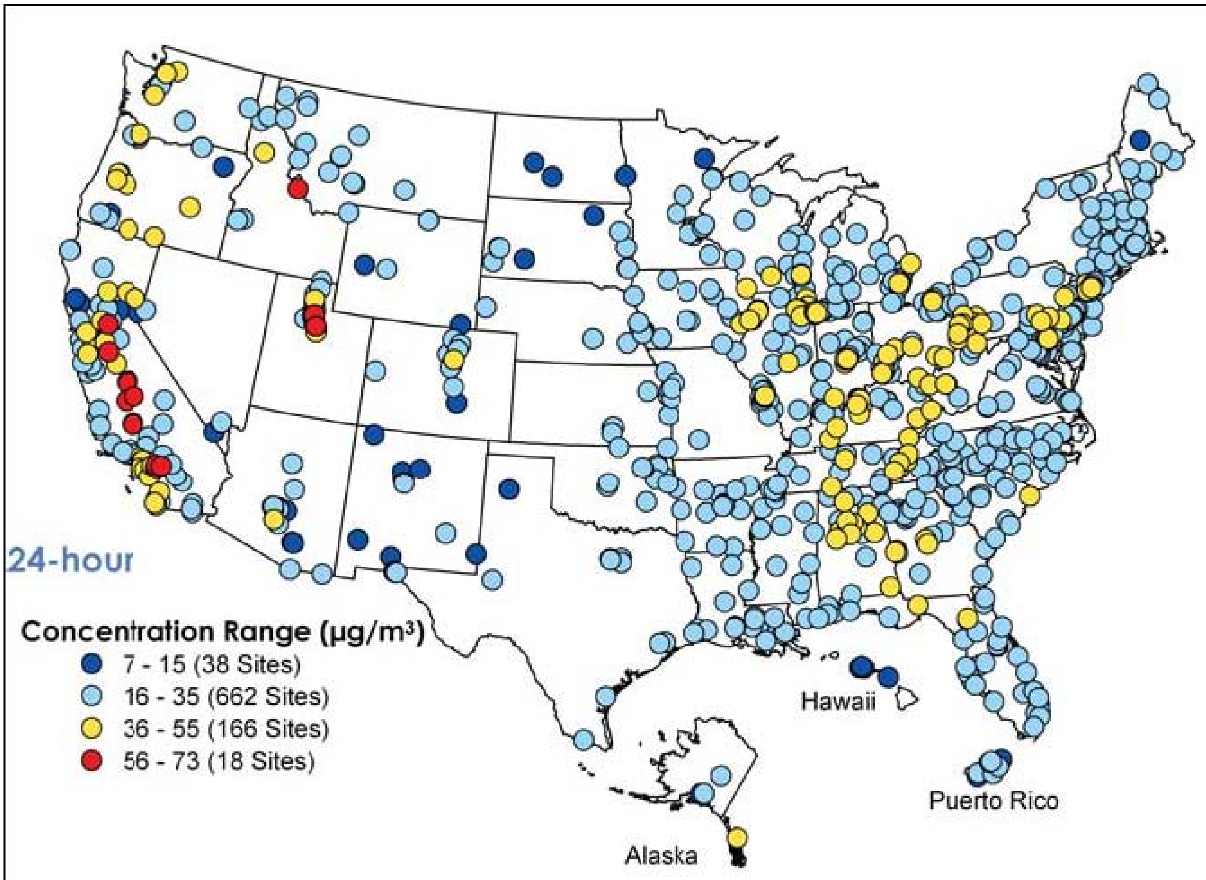

**Figure 3.4-3. 24-hour (98th percentile 24- hour concentrations) $PM_{2.5}$ Concentrations in µg/m$^3$ for 2007 (from 2008 Air Trends Report)**

The most recent revisions to the PM standards were in 1997 and 2006. In 2005, the U.S. EPA designated nonattainment areas for the 1997 $PM_{2.5}$ NAAQS (70 FR 19844, April 14, 2005).[TTTTTTTT] As of January 6, 2010, approximately 88 million people live in the 39 areas that are designated as nonattainment for the 1997 $PM_{2.5}$ National Ambient Air Quality Standard (NAAQS). These $PM_{2.5}$ nonattainment areas are comprised of 208 full or partial counties. Nonattainment areas for the 1997 $PM_{2.5}$ NAAQS are pictured in Figure 3.4-4. On October 8, 2009, the EPA issued final nonattainment area designations for the 2006 24-hour $PM_{2.5}$ NAAQS (74 FR 58688, November 13, 2009). These designations include 31 areas composed of 120 full or partial counties with a population of over 70 million. Nonattainment areas for the 2006 $PM_{2.5}$ NAAQS are pictured in Figure 3.4-5. In total, there are 54 $PM_{2.5}$ nonattainment areas composed of 245 counties with a population of 101 million people.

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[TTTTTTTT] A nonattainment area is defined in the Clean Air Act (CAA) as an area that is violating an ambient standard or is contributing to a nearby area that is violating the standard.

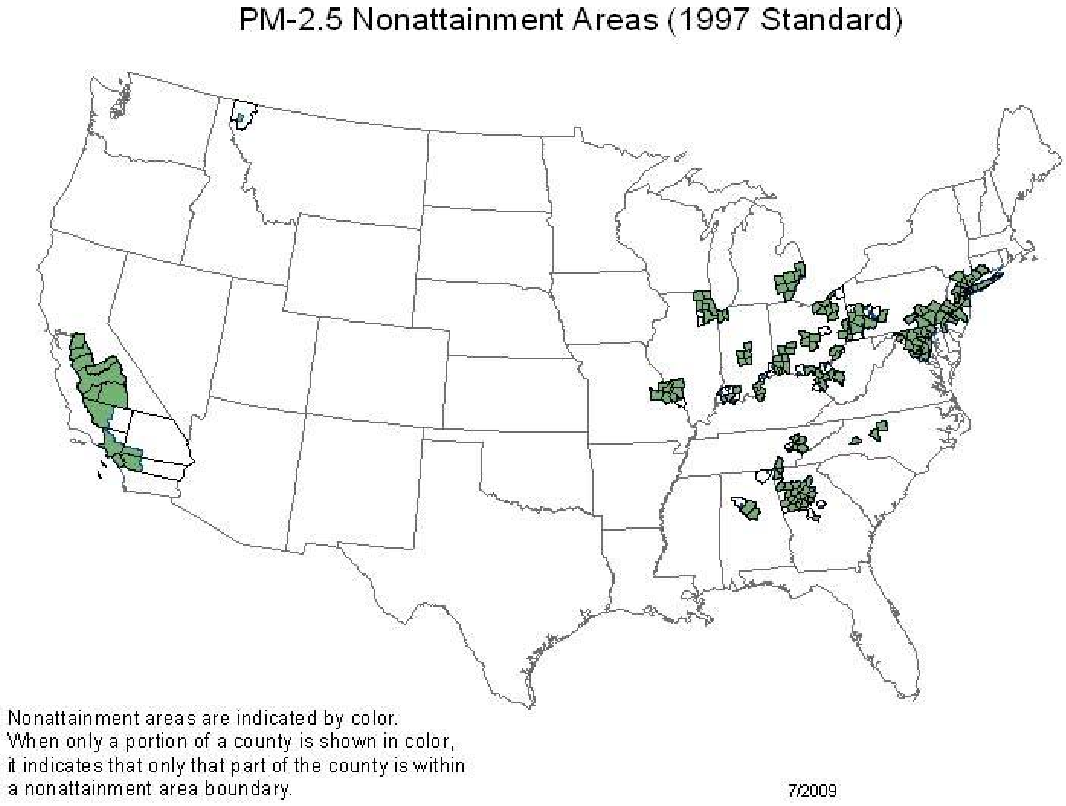

Figure 3.4-4. 1997 $PM_{2.5}$ Nonattainment Areas

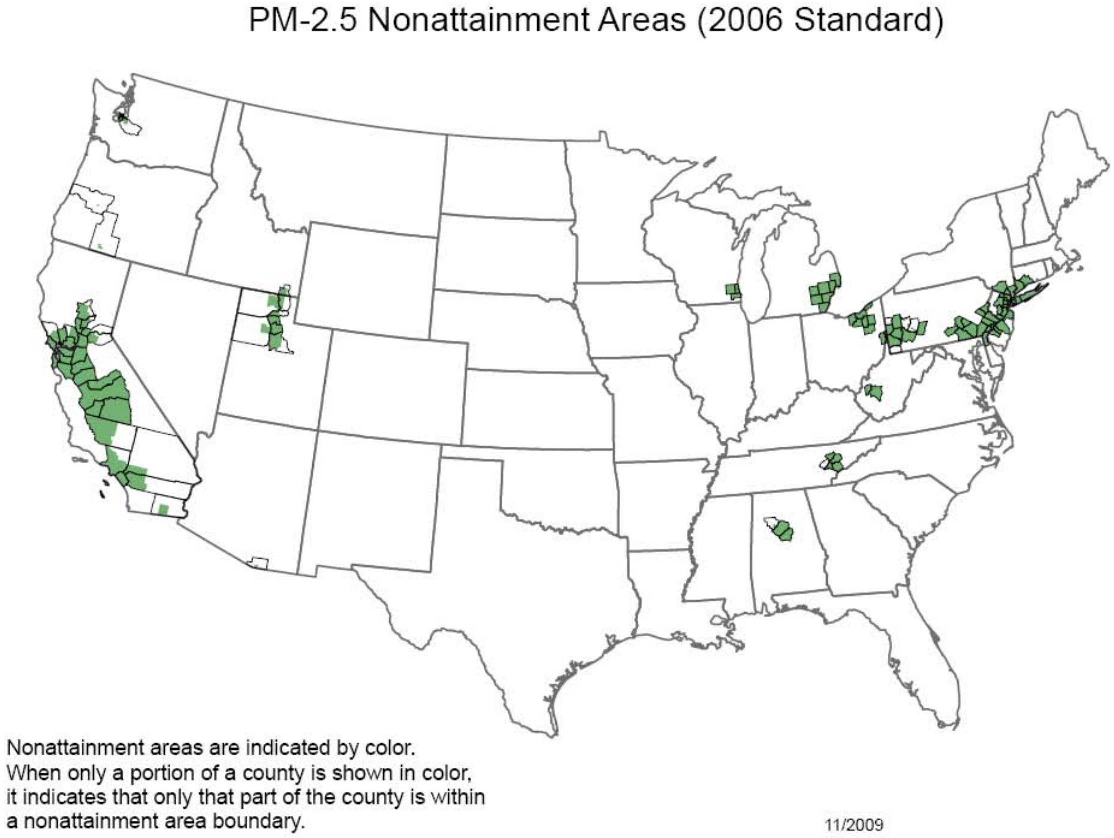

**Figure 3.4-5. 2006 $PM_{2.5}$ Nonattainment Areas**

As of January 6, 2010, approximately 26 million people live in the 47 areas that are designated as nonattainment for the $PM_{10}$ NAAQS. There are 40 full or partial counties that make up the $PM_{10}$ nonattainment areas. Nonattainment areas for the $PM_{10}$ NAAQS are pictured in Figure 3.4-6.

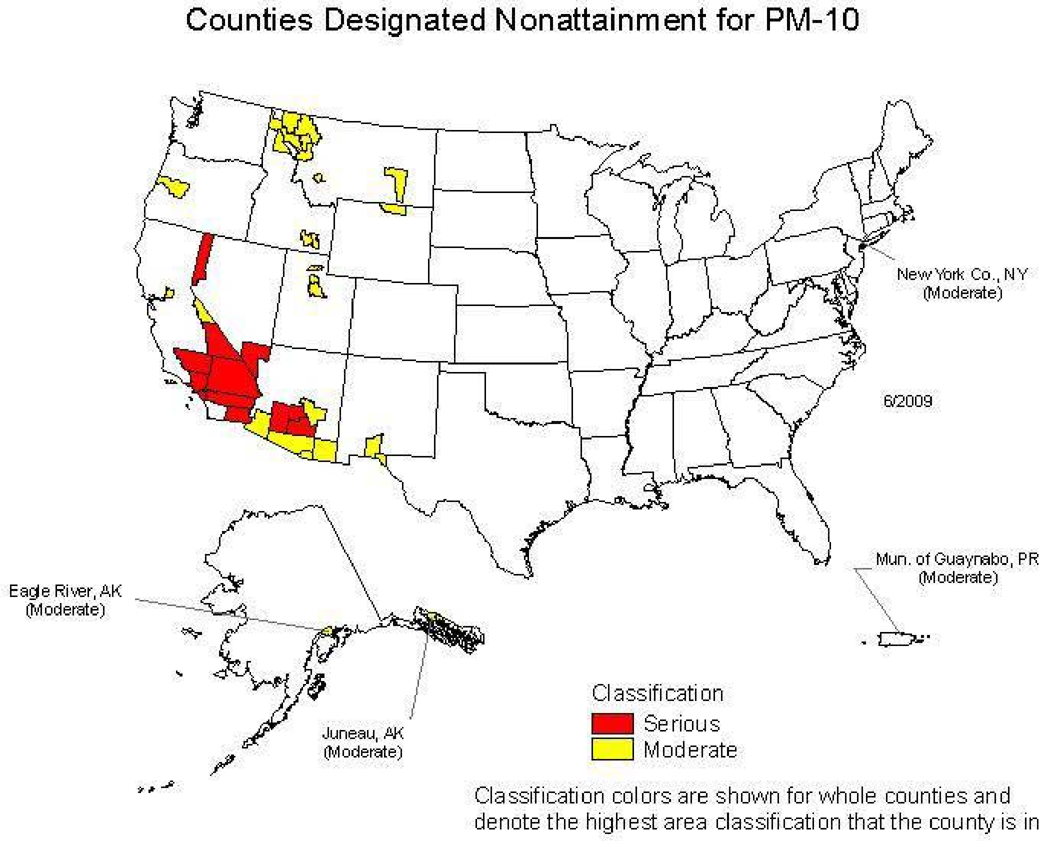

**Figure 3.4-6. $PM_{10}$ Nonattainment Areas**

### 3.4.2.1.1.2 Projected Levels of $PM_{2.5}$

Generally, our modeling indicates that the required renewable fuel volumes will reduce $PM_{2.5}$ concentrations in some areas of the country and increase $PM_{2.5}$ concentrations in other areas. In the following sections we describe projected $PM_{2.5}$ levels in the future, with and without the required renewable fuel volumes. Information on the air quality modeling methodology is contained in Section 3.4.1. Additional detail can be found in the air quality modeling technical support document (AQM TSD) in the docket for this rule.

#### 3.4.2.1.1.2.1 Projected $PM_{2.5}$ Levels without RFS2 Volumes

EPA has already adopted many mobile source emission control programs that are expected to reduce ambient PM levels. These control programs include the New Marine

Compression-Ignition Engines at or Above 30 Liters per Cylinder rule,[UUUUUUUU] the Marine Spark-Ignition and Small Spark-Ignition Engine rule (73 FR 59034, October 8, 2008), the Locomotive and Marine Compression-Ignition Engine Rule (73 FR 25098, May 6, 2008), the Clean Air Nonroad Diesel rule (69 FR 38957, June 29, 2004), the Heavy Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements (66 FR 5002, Jan. 18, 2001) and the Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements (65 FR 6698, Feb. 10, 2000). As a result of these programs, the number of areas that fail to meet the $PM_{2.5}$ NAAQS in the future is expected to decrease. However, even with the implementation of all current state and federal regulations, there are projected to be U.S. counties violating the $PM_{2.5}$ NAAQS well into the future.

Recent air quality modeling for the "Control of Emissions from New Marine Compression-Ignition Engines at or Above 30 Liters per Cylinder" rule projects that in 2020, at least 10 counties with a population of almost 25 million may not attain the 1997 annual $PM_{2.5}$ standard of 15 $\mu g/m^3$ and 47 counties with a population of over 53 million may not attain the 2006 24-hour $PM_{2.5}$ standard of 35 $\mu g/m^3$.[VVVVVVVV] Since the emission changes from the volumes of renewable fuel required by RFS2 will go into effect during the period when some areas are still working to attain the $PM_{2.5}$ NAAQS, the projected emission changes will impact state and local agencies in their effort to attain and maintain the $PM_{2.5}$ standard.

#### 3.4.2.1.1.2.2 Projected $PM_{2.5}$ Levels with RFS2 Volumes

This section includes a summary of the results of our modeling of $PM_{2.5}$ air quality impacts in the future due to the required renewable fuel volumes. We compare the RFS1 mandate reference case and AEO 2007 reference case scenarios to the RFS2 control scenario. When discussing the projected changes in $PM_{2.5}$ it is important to remember that there are uncertainties and limitations related to the air quality modeling (see Section 3.4.1.3), in large part due to uncertainties in projecting the future types of renewable fuels, the location of their production, and their method of use. Section 3.3 discusses the differences in the air quality modeling inventories and the final rule inventories in more detail.

Changes in ambient $PM_{2.5}$ concentrations due to required renewable fuel volumes are a result of changes to upstream and downstream emission sources, complex chemical reactions (direct emissions and secondary formation), transport and meteorology. As is detailed in Section 3.2, the required renewable fuel volumes impact upstream and tailpipe emissions of primary $PM_{2.5}$ and $PM_{2.5}$ precursors such as NOx and VOCs. Primary PM is emitted directly into the atmosphere and, on a mass basis, is largely carbonaceous in nature. Various studies have shown that mobile sources are a major source of primary PM in urban areas over many portions of the United States.[831,832,833,834,835,836,837] Primary PM that is carbonaceous is also referred to as primary organic aerosol (POA). Secondary PM is formed in the atmosphere from chemical

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[UUUUUUUU] This rule was signed on December 18, 2009 but has not yet been published in the Federal Register. The signed version of the rule is available at http://epa.gov/otaq/oceanvessels.htm).

[VVVVVVVV] US EPA (2009). Final Rule "Control of Emissions from New Marine Compression-Ignition Engines at or Above 30 Liters per Cylinder". This rule was signed on December 18, 2009 but has not yet been published in the Federal Register. The signed version of the rule is available at http://epa.gov/otaq/oceanvessels.htm).

transformations of gases. The forms of secondary PM most impacted by the renewable fuel volumes are nitrates and organics or secondary organic aerosol (SOA).

Due to the error in the PM inventory for locomotives we only present design value changes averaged over all 577 modeled counties, and do not present local impacts. The modeled counties are located across the country and have monitors that allow the calculation of a $PM_{2.5}$ design value. A large majority of the modeled counties will see relatively minor annual average $PM_{2.5}$ design value changes of between -0.05 µg/m$^3$ and +0.05 µg/m$^3$. On a population-weighted basis, the average modeled future-year annual $PM_{2.5}$ design values are projected to decrease by 0.002 µg/m$^3$ when compared with the RFS1 mandate or AEO reference case.[wwwwwwww] We also looked at changes in daily $PM_{2.5}$ design values. A majority of the modeled counties will see daily $PM_{2.5}$ design value changes of between -0.25 µg/m$^3$ and +0.25 µg/m$^3$. On a population-weighted basis, the average modeled future-year daily $PM_{2.5}$ design value is projected to decrease by 0.06 µg/m$^3$ when compared with the RFS1 mandate reference case or 0.05 µg/m$^3$ when compared with the AEO reference case.

The changes in ambient $PM_{2.5}$ described above are likely due to both increased emissions at biofuel production plants and from biofuel transport, and reductions in SOA formation and reduced emissions from gasoline refineries. In addition, decreases in ambient PM are predicted because our modeling inventory assumed large volumes of E85 use and also that E85 usage reduces PM tailpipe emissions. As mentioned previously, these direct PM emission reductions would not occur with final rule inventory assumptions.

#### 3.4.2.1.2 Ozone

As described in Section 3.5, ozone causes adverse health effects, and the EPA has set national ambient air quality standards (NAAQS) to protect against those health effects. In this section, we present information on current and model-projected future ozone levels.

##### 3.4.2.1.2.1 Current Levels of Ozone

Figure 3.4-7 shows a snapshot of ozone concentrations in 2007. The highest ozone concentrations were located in California, Connecticut, Georgia, Massachusetts, North Carolina, and Pennsylvania. Fifty-seven percent of the sites were above 0.075 ppm, the level of the 2008 standard.

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[wwwwwwww] Note that the change in annual average $PM_{2.5}$ for design values differs from the change in national population-weighted annual average $PM_{2.5}$ discussed in Sections I and VIII of the preamble and Chapter 5 of the RIA. National population-weighted annual average $PM_{2.5}$ with respect to health impacts is based on modeling data across all populated grid cells rather than just those counties with monitors. We find that there is a small increase in national population-weighted annual average $PM_{2.5}$ across all populated grid cells in the air quality modeling domain.

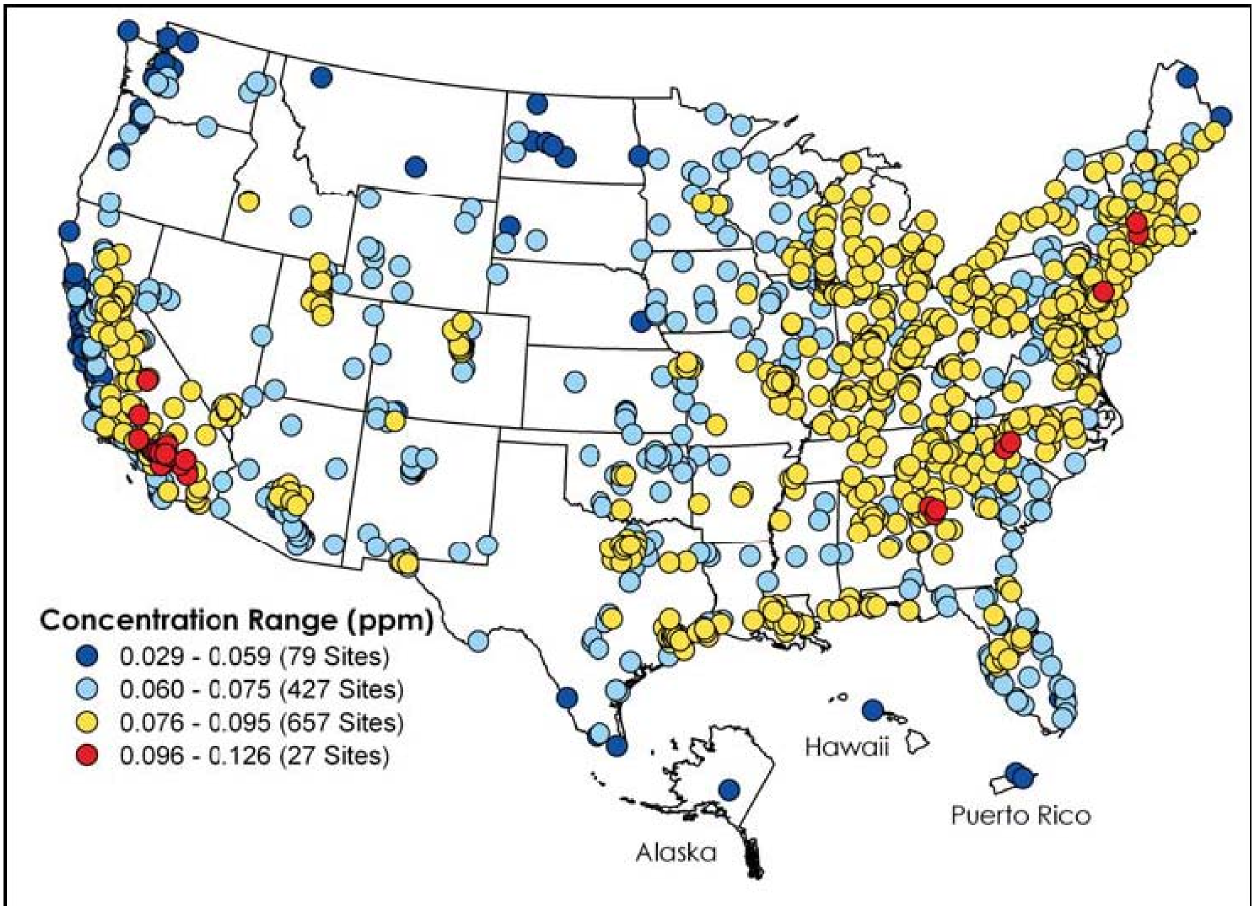

**Figure 3.4-7. Ozone Concentrations (fourth highest daily maximum 8-hour concentration) in ppm for 2007 (from 2008 Air Trends Report)**

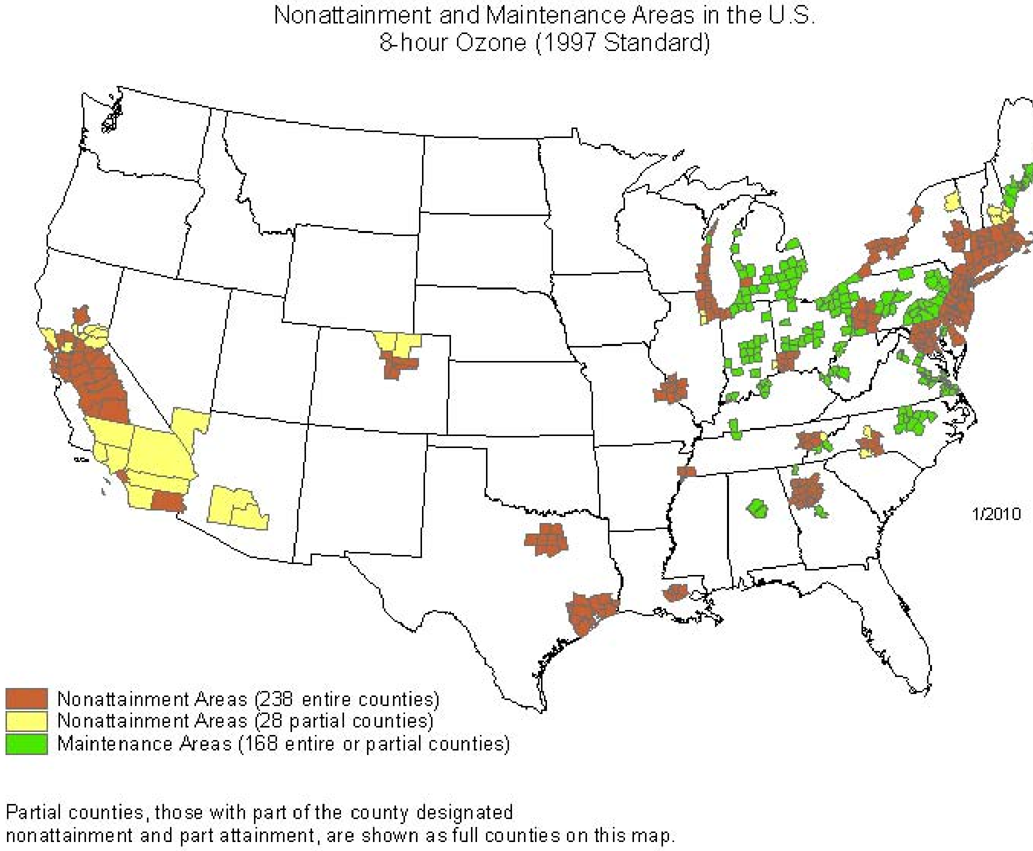

**Figure 3.4-8. 1997 Ozone Nonattainment Areas**

The primary and secondary national ambient air quality standards (NAAQS) for ozone are 8-hour standards set at 0.075 ppm. The most recent revision to these standards was in 2008; the previous 8-hour ozone standards, set in 1997, had been set at 0.08 ppm. In 2004, the U.S. EPA designated nonattainment areas for the 1997 8-hour ozone NAAQS (69 FR 23858, April 30, 2004). As of January 6, 2010, there are 51 8-hour ozone nonattainment areas for the 1997 ozone NAAQS composed of 266 full or partial counties with a total population of over 122 million. Figure 3.4-8 presents the 1997 NAAQS ozone nonattainment areas. On January 6, 2010, EPA proposed to reconsider the 2008 ozone NAAQS to ensure they are sufficiently protective of public health and the environment. EPA intends to complete the reconsideration by August 31, 2010. If, as a result of the reconsideration, EPA determines that the 2008 ozone standards are not supported by the scientific record and promulgates different ozone standards, the new 2010 ozone standards would replace the 2008 ozone standards and the requirement to designate areas for the replaced 2008 standards would no longer apply. Because of the significant uncertainty the reconsideration proposal creates regarding the continued applicability of the 2008 ozone NAAQS, EPA has extended the deadline for designating areas for the 2008 NAAQS by 1 year. If EPA promulgates new ozone standards in 2010, EPA intends to accelerate the designations process for the primary standard so that the designations would be effective in August 2011.

Table 3.4-1 provides an estimate, based on 2005-07 air quality data, of the counties with design values greater than the 2008 ozone NAAQS.

**Table 3.4-1.**
**Counties with Design Values Greater Than the 2008 Ozone NAAQS**
**Based on 2005-2007 Air Quality Data**

| | NUMBER OF COUNTIES | POPULATION[a] |
|---|---|---|
| 1997 Ozone Standard:  counties within the 51 areas currently designated as nonattainment (as of 1/6/10) | 266 | 122,343, 799 |
| 2008 Ozone Standard:  additional counties that would not meet the 2008 NAAQS[b] | 227 | 41,285,262 |
| **Total** | 493 | 163,629,061 |

Notes:
[a] Population numbers are from 2000 census data.
[b] Area designations for the 2008 ozone NAAQS have not yet been made.  Nonattainment for the 2008 Ozone NAAQS would be based on three years of air quality data from later years.  Also, the county numbers in the table include only the counties with monitors violating the 2008 Ozone NAAQS.  The numbers in this table may be an underestimate of the number of counties and populations that will eventually be included in areas with multiple counties designated nonattainment.

3.4.2.1.2.2 Projected Levels of Ozone

Achieving the required renewable fuel volumes by 2022 is projected to adversely impact ozone air quality over much of the U.S.  However, ozone air quality improvements are projected in a few highly-populated areas which currently have poor air quality.  In the following sections we describe projected ozone levels in the future resulting from the increased use of renewable fuels. Information on the air quality modeling methodology is contained in Section 3.4.1. Additional detail can be found in the air quality modeling technical support document (AQM TSD) in the docket for this rule.

3.4.2.1.2.2.1 Projected Ozone Levels without RFS2 Volumes

EPA has already adopted many emission control programs that are expected to reduce ambient ozone levels.  These control programs include the New Marine Compression-Ignition Engines at or Above 30 Liters per Cylinder rule,[xxxxxxxx] the Marine Spark-Ignition and Small Spark-Ignition Engine rule (73 FR 59034, October 8, 2008), the Locomotive and Marine Rule (73 FR 25098, May 6, 2008), the Clean Air Interstate Rule (70 FR 25162, May 12, 2005), the Clean Air Nonroad Diesel rule (69 FR 38957, June 29, 2004), and the Heavy Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements (66 FR 5002, Jan. 18, 2001).  As a result of these programs, 8-hour ozone levels are expected to improve in the future.

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[xxxxxxxx] This rule was signed on December 18, 2009 but has not yet been published in the Federal Register.  The signed version of the rule is available at http://epa.gov/otaq/oceanvessels.htm).

The baseline air quality modeling projects that in 2022, with all current controls in effect but excluding the emissions changes expected to occur as a result of the required renewable fuel volumes, at least 7 counties, with a projected population of over 22 million people, may not attain the 1997 8-hour ozone standard of 0.08 ppm and at least 25 counties, with a projected population of nearly 41 million people, may not attain the 2008 8-hour ozone standard of 75 ppb. This modeling supports the conclusion that there are a number of counties across the U.S. projected to experience ozone concentrations at or above the ozone NAAQS into the future. Since the emission changes from the required renewable fuel volumes go into effect during the period when some areas are still working to attain the ozone NAAQS, the projected emission changes will impact state and local agencies in their effort to attain and maintain the ozone standard. In the following section we discuss projected nonattainment areas and how they compare to the areas which are projected to experience either ozone reductions or ozone increases from the required renewable fuel volumes.

### 3.4.2.1.2.2.2 Projected Ozone Levels with RFS2 Volumes

This section summarizes the results of our modeling of ozone air quality impacts in the future due to required renewable fuel volumes. Specifically, we compare the RFS1 mandate and AEO 2007 reference case scenarios to the RFS2 control scenario.[YYYYYYYY] Our modeling indicates that the required renewable fuel volumes will increase ozone design value concentrations in many areas of the country and decrease ozone design value concentrations in a small number of areas. Figures 3.4-9 and 3.4-10 present the changes in 8-hour ozone design value concentration in 2022 when the RFS2 control scenario is compared to the RFS1 mandate reference case and the AEO 2007 reference case respectively.

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[YYYYYYYY] We used a different speciation profile for E10 gasoline headspace emissions in the EISA control case than was used for the RFS1 and AEO 2007 reference cases. This inconsistency is described in Section 3.4.1.3.

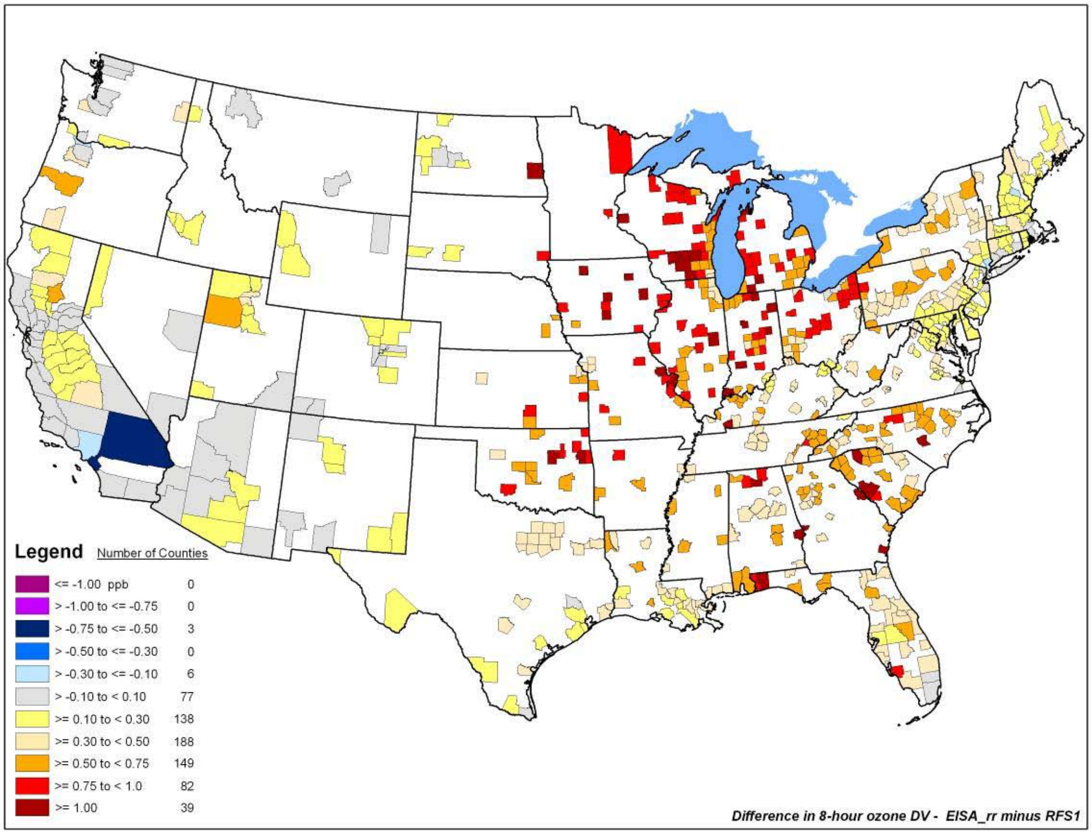

**Figure 3.4-9. Projected Change in 2022 8-hour Ozone Design Values Between the RFS2 Control Scenario and RFS1 Mandate Reference Case Scenario**

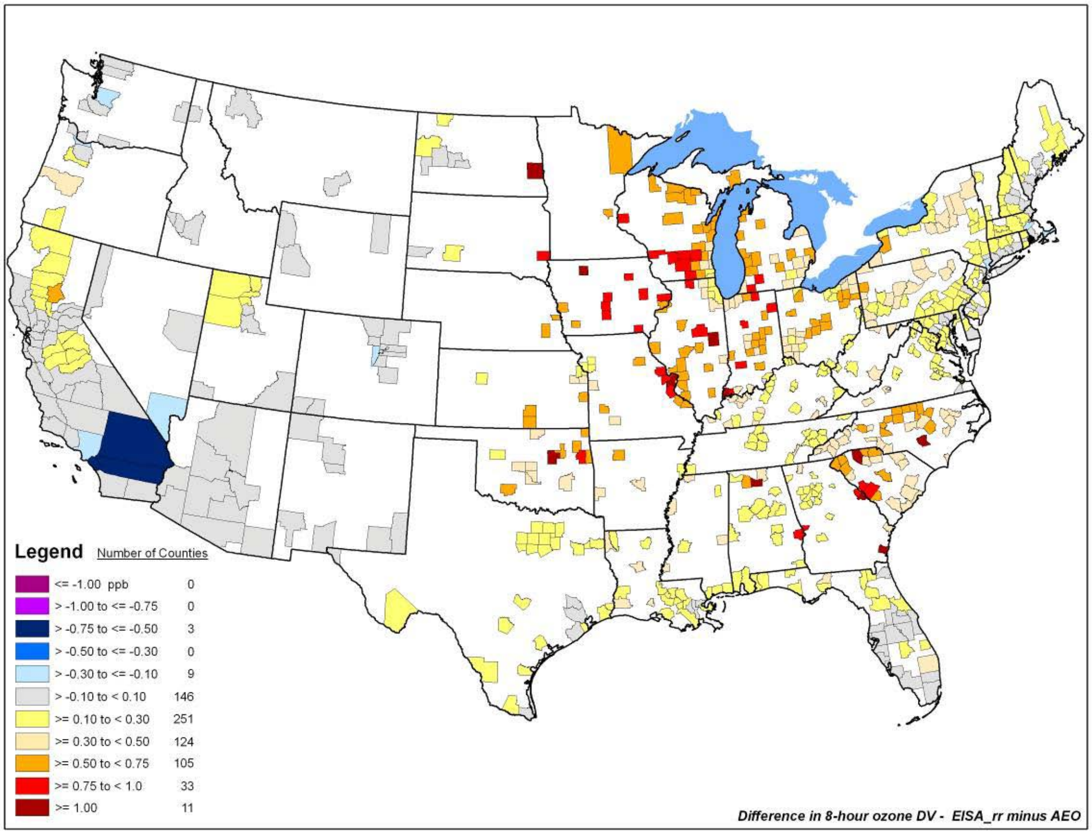

**Figure 3.4-10. Projected Change in 2022 8-hour Ozone Design Values Between the RFS2 Control Scenario and AEO 2007 Reference Case Scenario**

As can be seen in Figure 3.4-9 and 3.4-10 most counties with modeled data, especially those in the Midwest, see increases in their ozone design values. The majority of these design value increases are less than 0.5 ppb. However, there are some counties that will see 8-hour ozone design value increases above 0.5 ppb; these counties are mainly in the eastern U.S. The maximum projected increase in an 8-hour ozone design value is in Morgan County, Alabama, 1.56 ppb and 1.27 ppb when compared with the RFS1 mandate and AEO 2007 reference cases respectively. There are also some counties that are projected to see 8-hour ozone design value decreases. The counties with ozone design value decreases greater than 0.5 ppb are in Southern California. The maximum decrease projected in an 8-hour ozone design value is in Riverside, CA, 0.66 ppb and 0.60 ppb when compared with the RFS1 mandate and AEO 2007 reference cases respectively.

There are 26 counties, mainly in California, that are projected to have 8-hour ozone design values above the 2008 NAAQS in 2022 with the required renewable fuel volumes in place. Table 3.4-2 below presents the changes in design values for these counties when comparing the RFS2 control scenario with the RFS1 mandate and AEO 2007 reference case scenarios.

### Table 3.4-2.
### Change in Ozone Design Values (ppb) for Counties Projected to be Above the 2008 Ozone NAAQS in 2022

| | RFS2 control - RFS1 mandate | RFS2 control – AEO 2007 |
|---|---|---|
| San Bernardino County, California | -0.58 | -0.53 |
| Riverside County, California | -0.66 | -0.60 |
| Los Angeles County, California | -0.16 | -0.16 |
| Kern County, California | 0.02 | -0.02 |
| Tulare County, California | 0.34 | 0.07 |
| Harris County, Texas | 0.12 | 0.05 |
| Fresno County, California | 0.11 | 0.08 |
| Brazoria County, Texas | 0.18 | 0.09 |
| Suffolk County, New York | -0.09 | -0.05 |
| East Baton Rouge County, Louisiana | 0.39 | 0.27 |
| Sacramento County, California | 0.04 | 0.04 |
| Orange County, California | -0.57 | -0.52 |
| Calaveras County, California | 0.15 | 0.14 |
| Nevada County, California | 0.07 | 0.06 |
| El Dorado County, California | 0.05 | 0.04 |
| Harford County, Maryland | 0.23 | 0.03 |
| Ventura County, California | -0.01 | -0.03 |
| Fairfield County, Connecticut | -0.08 | -0.08 |
| Placer County, California | 0.05 | 0.04 |
| San Diego County, California | 0.25 | 0.19 |
| Merced County, California | -0.10 | -0.09 |
| Westchester County, New York | 0.35 | 0.23 |
| Kenosha County, Wisconsin | -0.11 | -0.11 |
| Philadelphia County, Pennsylvania | 0.19 | 0.12 |
| New Haven County, Connecticut | 0.92 | 0.68 |

Table 3.4-3 shows the average change in 2022 8-hour ozone design values for: (1) all counties with 2005 baseline design values, (2) counties with 2005 baseline design values that exceeded the 2008 ozone standard, (3) counties with 2005 baseline design values that did not exceed the 2008 standard, but were within 10% of it, (4) counties with 2022 design values that exceeded the 2008 ozone standard, and (5) counties with 2022 design values that did not exceed the standard, but were within 10% of it. Counties within 10% of the standard are intended to reflect counties that meet the standard, but will likely benefit from help in maintaining that status in the face of growth. Many of these statistics show an increase in ozone design values in 2022, more often when compared with the RFS1 case, but the magnitude of the increase varies and there are some statistics which show a decrease in 8-hour ozone design values. On a population-weighted basis, the average modeled future-year 8-hour ozone design values are projected to increase by 0.28 ppb in 2022 when compared with the RFS1 mandate reference case and increase by 0.16 ppb when compared with the AEO 2007 reference case. On a population-weighted basis

those counties that are projected to be above the 2008 ozone standard in 2022 will see decreases of 0.14 when compared with the RFS1 mandate reference and 0.15 ppb when compared with the AEO 2007 reference case scenario.

### Table 3.4-3.
### Average Change in Projected Future Year 8-hour Ozone Design Value as a Result of the Required Renewable Fuel Volumes

| AVERAGE[a] | NUMBER OF US COUNTIES | 2020 POPULATION[b] | CHANGE IN 2022 DESIGN VALUE (PPB) RFS2-RFS1 | CHANGE IN 2022 DESIGN VALUE (PPB) RFS2-AEO 2007 |
|---|---|---|---|---|
| All | 678 | 238,378,342 | 0.46 | 0.30 |
| All, population-weighted | 678 | 238,378,342 | 0.28 | 0.16 |
| Counties whose 2005 base year is violating the 2008 8-hour ozone standard | 389 | 174,967,297 | 0.44 | 0.28 |
| Counties whose 2005 base year is violating the 2008 8-hour ozone standard, population-weighted | 389 | 174,967,297 | 0.26 | 0.14 |
| Counties whose 2005 base year is within 10 percent of the 2008 8-hour ozone standard | 208 | 43,172,228 | 0.52 | 0.36 |
| Counties whose 2005 base year is within 10 percent of the 2008 8-hour ozone standard, population-weighted | 215 | 45,008,435 | 0.35 | 0.22 |
| Counties whose 2022 RFS2 control case is violating the 2008 8-hour ozone standard | 26 | 41,017,324 | 0.04 | 0.00 |
| Counties whose 2022 RFS2 control case is violating the 2008 8-hour ozone standard, population-weighted | 26 | 41,017,324 | -0.14 | -0.15 |
| Counties whose 2022 RFS2 control case is within 10% of the 2008 8-hour ozone standard | 110 | 61,618,519 | 0.34 | 0.22 |
| Counties whose 2022 RFS2 control case is within 10% of the 2008 8-hour ozone standard, population-weighted | 110 | 61,618,519 | 0.31 | 0.19 |

Notes:
[a] Averages are over counties with 2005 modeled design values
[b] Population numbers based on 2000 census data

Ground-level ozone pollution is formed by the reaction of VOCs and NOx in the atmosphere in the presence of heat and sunlight. The science of ozone formation, transport, and accumulation is complex.[838] The projected ozone increases in some areas and decreases in other areas which are seen in the air quality modeling for this final rule are likely a result of the emissions changes due to the increased volumes of renewable fuels combined with the photochemistry involved, the different background concentrations of VOCs and NOx in different areas of the country, and the different meteorological conditions in different areas of the country. When VOC levels are relatively high, relatively small amounts of NOx enable ozone to form rapidly. Under these conditions VOC reductions have little effect on ozone and while NOx reductions are highly effective in reducing ozone, NOx increases lead to increases in ozone. Such conditions are called "NOx-limited." Because the contribution of VOC emissions from biogenic (natural) sources to local ambient ozone concentrations can be significant, even some areas where man-made VOC emissions are relatively low can be NOx-limited. Rural areas are usually NOx-limited, due to the relatively large amounts of biogenic VOC emissions in such areas. The ozone increases seen in the southeastern U.S. and many of the other rural areas are likely due to the fact that those areas are NOx-limited and this final rule is projected to increase NOx and decrease VOCs. A recent review article looking at ethanol in gasoline indicates that increasing usage of E10 fuels, when compared with E0 fuels, can increase NOx emissions and thereby increase ozone concentrations (see Section 3.4.3.3).[839]

When NOx levels are relatively high and VOC levels relatively low, NOx forms inorganic nitrates (i.e., particles) but relatively little ozone. Such conditions are called "VOC-limited." Under these conditions, VOC reductions are effective in reducing ozone, but NOx reductions can actually increase local ozone under certain circumstances. In the air quality modeling done for this final rule, the ozone decreases seen in southern California and some of the other urban areas, like Cleveland and Miami, are likely due to the fact that those areas are VOC-limited areas and they are projected to see decreases in VOCs and increases in NOx due to this final rule.

As mentioned in Section 3.3, the inventories used for the air quality modeling differ from those being presented in this final rule, and as mentioned in Section 3.4.1.3, there are uncertainties and limitations related to the air quality modeling. When looking at the changes in projected ozone the most important uncertainty has to do with the fact that the modeled inventory assumes increases in NOx for vehicles using E10 fuel. These NOx increases contribute to the ozone increases in NOx-limited areas and the ozone decreases in VOC-limited areas.

#### 3.4.2.1.3 Air Toxics

##### 3.4.2.1.3.1 Current Levels of Air Toxics

The majority of Americans continue to be exposed to ambient concentrations of air toxics at levels which have the potential to cause adverse health effects.[840] The levels of air toxics to which people are exposed vary depending on where people live and work and the kinds of activities in which they engage, as discussed in detail in U.S. EPA's recent Mobile Source Air Toxics Rule.[841] In order to identify and prioritize air toxics, emission source types and locations which are of greatest potential concern, U. S. EPA conducts the National-Scale Air Toxics Assessment (NATA). The most recent NATA was conducted for calendar year 2002, and was released in June 2009.[842] NATA for 2002 includes four steps:

1) Compiling a national emissions inventory of air toxics emissions from outdoor sources

2) Estimating ambient concentrations of air toxics across the United States

3) Estimating population exposures across the United States

4) Characterizing potential public health risk due to inhalation of air toxics including both cancer and noncancer effects

Figures 3-4.11 and 3-4.12 depict estimated county-level carcinogenic risk and noncancer respiratory hazard from the assessment. The respiratory hazard is dominated by a single pollutant, acrolein.

According to NATA for 2002, mobile sources were responsible for 47 percent of outdoor toxic emissions, over 50 percent of the cancer risk, and over 80 percent of the noncancer hazard.[843,zzzzzzzz] Benzene is the largest contributor to cancer risk of all 124 pollutants quantitatively assessed in the 2002 NATA, and mobile sources were responsible for 59 percent of benzene emissions in 2002. Over the years, EPA has implemented a number of mobile source and fuel controls which have resulted in VOC reductions, which also reduced benzene and other air toxic emissions.

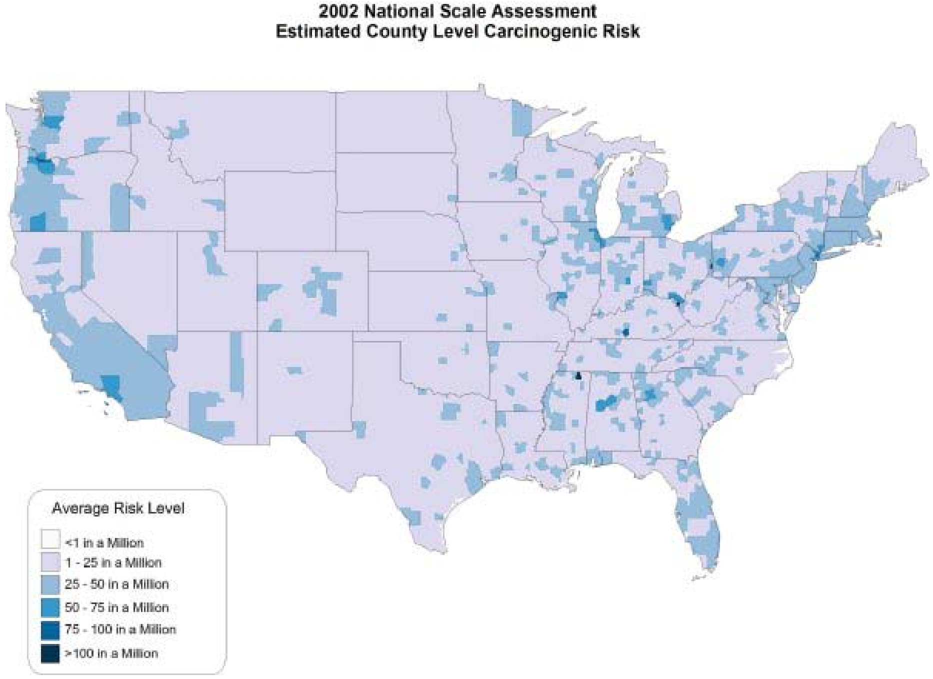

Figure 3-4.11. County Level Average Carcinogenic Risk, 2002 NATA.

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[zzzzzzzz] NATA relies on a Guassian plume model, Assessment System for Population Exposure Nationwide (ASPEN), to estimate toxic air pollutant concentrations. Projected air toxics concentrations presented in this rule were modeled with CMAQ 4.7, which has only recently been updated to include air toxics.

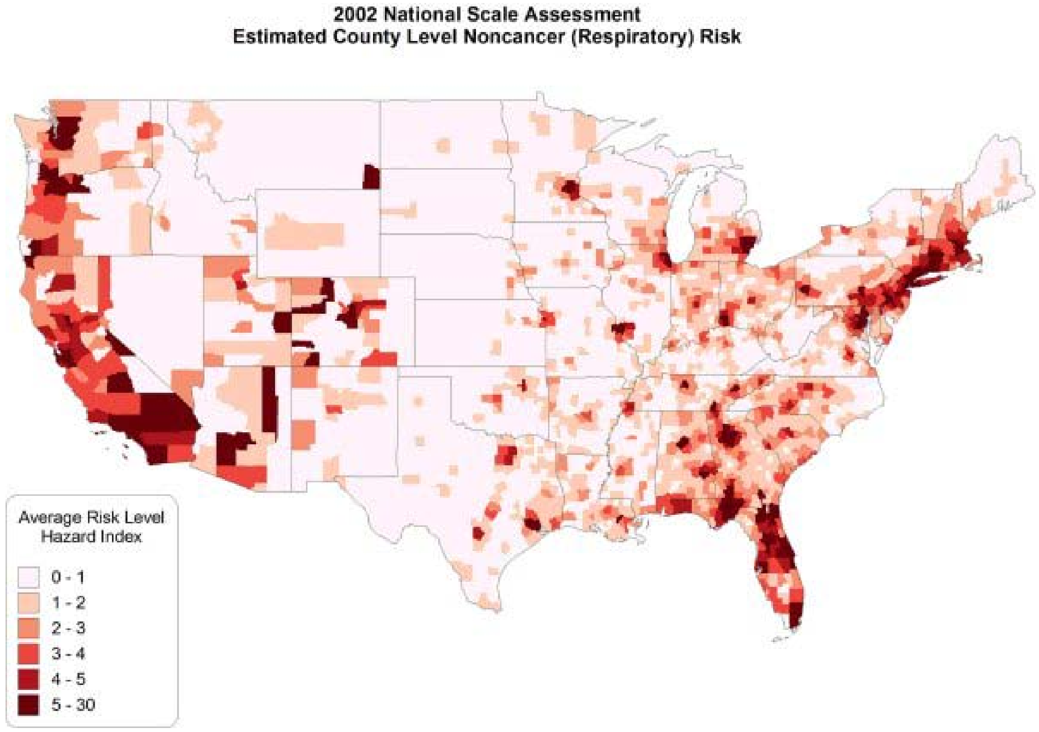

**Figure 3-4.12. County Level Average Noncancer Hazard Index, 2002 NATA.**

#### 3.4.2.1.3.2 Projected Levels of Air Toxics

In the following sections, we describe results of our modeling of air toxics levels in the future with the renewable fuel volumes required by this action. Although a large number of compounds which are considered air toxics could be impacted by increases in renewable fuel volumes, we focused on those which were identified as national and regional-scale cancer and noncancer risk drivers in the 2002 NATA[844] and were also likely to be significantly impacted by the renewable fuel volumes required by RFS2. These compounds include benzene, 1,3-butadiene, formaldehyde, acetaldehyde, and acrolein. Ethanol impacts were also included in our analyses because of health concerns (Section 3.4.5) and its role as an acetaldehyde precursor. Information on the air quality modeling methodology is contained in Section 3.4.1.1. Additional detail can be found in the air quality modeling technical support document (AQM TSD) in the docket for this rule.

It should be noted that EPA has adopted many mobile source emission control programs that are expected to reduce ambient air toxics levels. These control programs include the Heavy-duty Onboard Diagnostic Rule (74 FR 8310, February 24, 2009), Small SI and Marine SI Engine Rule (73 FR 59034, October 8, 2008), Locomotive and Commercial Marine Rule (73 FR 25098, May 6, 2008), Mobile Source Air Toxics Rule (72 FR 8428, February 26, 2007), Clean Air Nonroad Diesel Rule (69 FR 38957, June 29, 2004), Heavy Duty Engine and Vehicle Standards and Highway Diesel Fuel Sulfur Control Requirements (66 FR 5002, Jan. 18, 2001) and the Tier 2 Motor Vehicle Emissions Standards and Gasoline Sulfur Control Requirements (65 FR 6698, Feb. 10, 2000). As a result of these programs, the ambient concentration of air toxics in the future is expected to decrease. The reference case and control case scenarios include these controls.

This section summarizes the results of our modeling of ambient air toxics impacts in the future from the renewable fuel volumes required by RFS2. Specifically, we compare the RFS1 mandate and AEO 2007 reference scenarios to the RFS2 control scenario for 2022 (see Section 3.3 for more information on the scenarios).[AAAAAAAAA] Our modeling indicates that, while there are some localized impacts, the renewable fuel volumes required by RFS2 have relatively little impact on national average ambient concentrations of the modeled air toxics. An exception is increased ambient concentrations of ethanol. Because overall impacts are small, we concluded that assessing exposure to ambient concentrations and conducting a quantitative risk assessment of air toxic impacts was not warranted. However, we did develop population metrics, including the population living in areas with increases or decreases in concentrations of various magnitudes. We also estimated aggregated populations above and below reference concentrations for noncancer effects.

Our discussion of the air quality modeling for air toxics primarily focuses on impacts of the renewable fuel volumes required by RFS2 in reference to the RFS1 mandate for 2022; this comparison has a greater difference in projected ethanol volumes between the reference and the control case than a comparison using the AEO 2007 reference case. Except where specifically discussed below, air quality modeling results of the RFS2 control case in comparison with the AEO 2007 reference case are presented in Appendix 3.A of this RIA.

### Acetaldehyde

Our air quality modeling does not show substantial overall nationwide impacts on ambient concentrations of acetaldehyde as a result of the renewable fuel volumes required by this rule. Annual percent changes in ambient concentrations of acetaldehyde are less than 1% for most of the country (Figure 3.4-13). Several urban areas show decreases in ambient acetaldehyde concentrations ranging from 1 to 10%, and some rural areas associated with new ethanol plants show increases in ambient acetaldehyde concentrations ranging from 1 to 10% with RFS2. Annual absolute changes in ambient concentrations of acetaldehyde are generally less than 0.1 $\mu g/m^3$ (Figure 3.4-14). However, as discussed below, there are considerable limitations and uncertainties in our assessment of impacts of the renewable fuel volumes required by this rule on ambient concentrations of acetaldehyde.

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[AAAAAAAAA] We used a different speciation profile for E10 gasoline headspace emissions in the RFS2 control case than was used for the RFS1 and AEO reference cases. This inconsistency is described in Section 3.4.1.3.

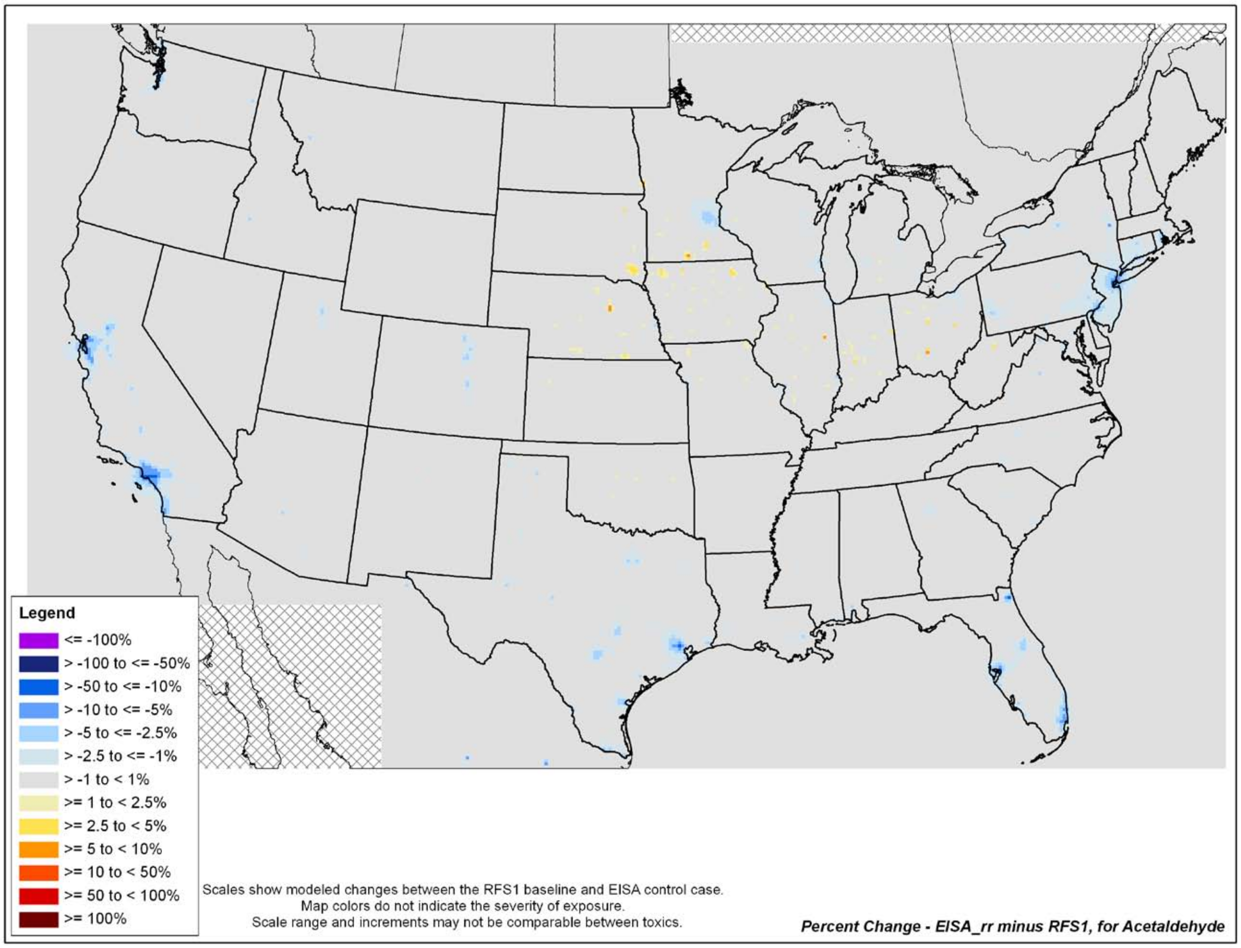
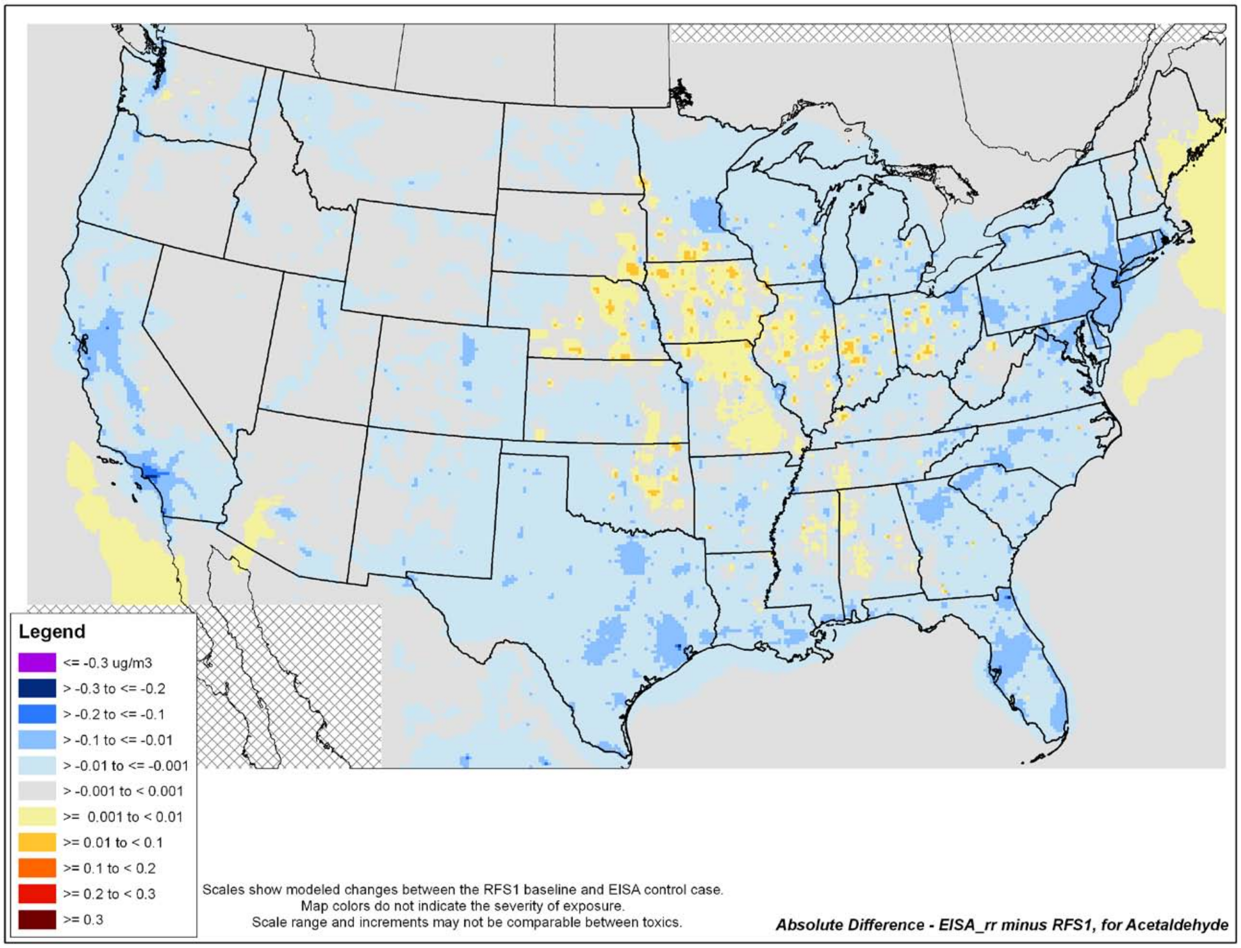


**Figure 3.4-13. Acetaldehyde Annual Percent Change in Concentration Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022**



Scales show modeled changes between the RFS1 baseline and EISA control case.
Map colors do not indicate the severity of exposure.
Scale range and increments may not be comparable between toxics.

*Absolute Difference - EISA_rr minus RFS1, for Acetaldehyde*

**Figure 3.4-14. Acetaldehyde Annual Absolute Changes in Ambient Concentrations Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022 (µg/m³)**

As noted above, the results show that the largest increases in ambient acetaldehyde concentrations with RFS2 volumes occur in areas associated with new ethanol plants. This result is due to an increase in emissions of primary acetaldehyde and precursor emissions from ethanol plants not included in the RFS1 baseline scenario. Locations for projected corn ethanol plants emissions were based on existing or planned plants, whereas cellulosic ethanol plants were projected based on available feedstocks. Details on how this was done are described in Section 1.8 of the RIA.[845] As discussed in Section 3.4.1.3, the location of these localized increases is limited by uncertainties in the placement of the new plants.

Significant increases in ambient acetaldehyde might be expected based on the significant increases in primary acetaldehyde and ethanol emissions (18% and 16% for the primary case relative to RFS1, nationally, as described in Section 3.2). However, the chemical formation of acetaldehyde is complex; most ambient acetaldehyde is formed from secondary photochemical reactions of numerous precursor compounds, and many photochemical mechanisms are responsible for this process (see Section 3.4.1.2 and 3.4.1.3). As discussed in more detail in Section 3.4.3.1, some previous U.S. monitoring studies have suggested an insignificant or small impact of increased use of ethanol in fuel on ambient acetaldehyde.[846,847,848] These studies suggest that increases in direct emissions of acetaldehyde are offset by decreases in the secondary formation of acetaldehyde. Other past studies have shown increases in ambient acetaldehyde with increased use of ethanol in fuel, although factors such as differences in vehicle fleet, lack of RVP control, exclusion of upstream impacts, and differences in the levels of other compounds in the ambient air may limit the ability of these studies to inform expected impacts on ambient air quality (Section 3.4.3.1). Given the conflicting results among past studies and the limitations of our analysis as discussed in the following paragraphs, considerable additional work is needed to address the impacts of the renewable fuel volumes required by this rule on ambient concentrations of acetaldehyde.

The comparison of the RFS1 mandate reference case with the RFS2 control case for summer and winter shows decreases in ambient acetaldehyde concentrations in urban areas (Figures 3.4-13 and 3.4-14). Decreases are less pronounced in winter when there is less secondary formation of acetaldehyde (Figures 3.4-15 and 3.4-16). A key reason for the decrease in urban areas is reductions in certain acetaldehyde precursors, primarily alkenes (olefins). These reductions are due to differences in the E0 gasoline headspace speciation profiles used for the control case and the reference cases, as discussed in Section 3.4.1.3. Headspace profiles are used to speciate hydrocarbon emissions from gasoline storage, gasoline distribution, and gas cans. The differences between cases arose when EPA noticed that the headspace profiles used in the reference case scenarios exhibited a reduction in alkene levels going from E0 to E10 that was not consistent with what one would expect as a result of increased ethanol use. In these cases, the E0 gasoline headspace profile has 13% of the VOC as alkenes and the E10 profile has an alkene content of 4%.

To address this issue, EPA adjusted the E0 headspace profile based on the assumption that the emissions have an alkene content of 4%, consistent with the percent alkene content of the E10 headspace profile because a 13% alkene content is much higher than typically seen in fuel surveys and one expects the headspace from E0 and E10 to be similar.[849] However, due to time constraints, we were not able to make this improvement for the reference cases. Thus, alkene levels associated with E0 use are lower in the control case than the reference cases, leading to a reduction in secondarily formed acetaldehyde.

To determine the potential impact of this inconsistency, EPA conducted a sensitivity analysis of the RFS1 mandate reference case for the Eastern U.S. modeling domain.[BBBBBBBBB] This sensitivity analysis was conducted for a single month, July, and compared results with the control case for the following two cases:

1) RFS1 case with no change in alkene levels between headspace profiles for E0 and E10 (i.e., adjusted E0 profile)

2) RFS1 case with higher alkene levels for E0 headspace profile

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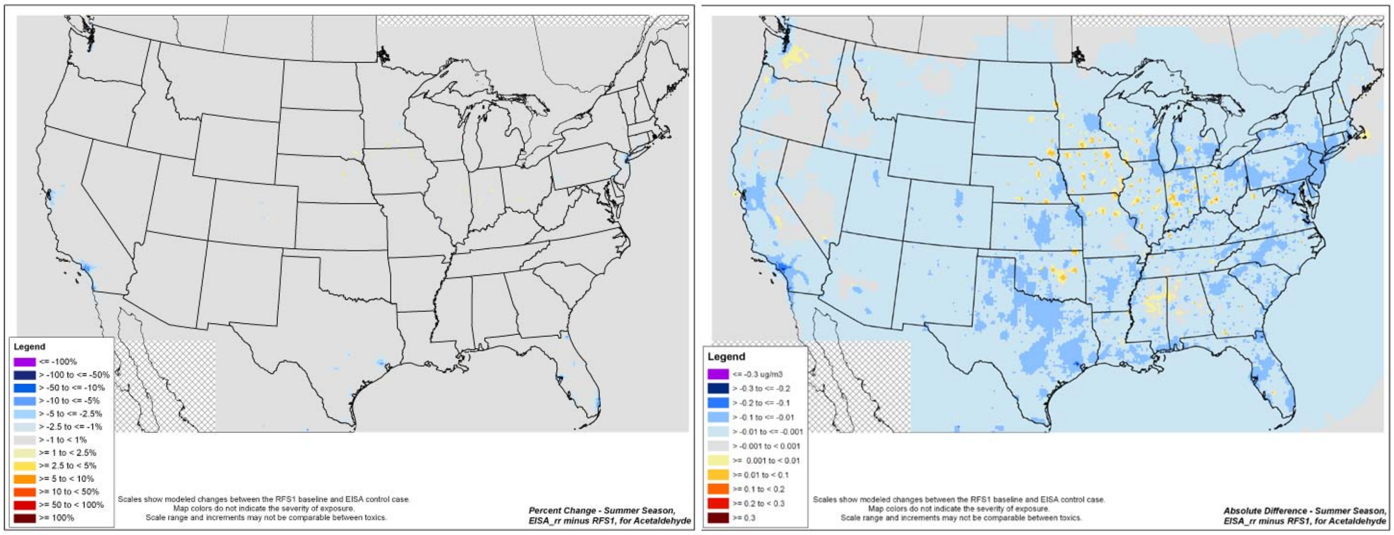
[BBBBBBBBB] Details of the sensitivity run are discussed in the AQ modeling TSD, found in the docket for this rule (EPA-HQ-OAR-2005-0161).

The results of the sensitivity analysis showed that acetaldehyde levels were significantly higher for the comparison between Case 1 and the control case than for the comparison between Case 2 and the control case. The sensitivity analysis thus confirmed that the decrease in these acetaldehyde precursors between the reference cases and the control case E0 headspace profile is driving the decrease in ambient concentrations of acetaldehyde in urban areas. Thus, while the air quality modeling results presented in this RIA suggest impacts of increased renewable fuel use on ambient acetaldehyde are not substantial and there may be decreases in urban areas, there is considerable uncertainty associated with these results. In fact, if the reference cases were rerun with revised E0 headspace profiles, some of the observed decreases could become increases. Additional research is underway to address these uncertainties, e.g., measurement of representative fuels to create better headspace speciation profiles (Section 3.4.1.3) and improvements in other speciation profiles based on additional results from the EPAct emissions test program.[CCCCCCCCC]

It should also be noted (see Section 3.3 above) that we modeled the "more sensitive" emission inventory case similar to that presented in the NPRM which assumed that use of E10 would lead to increases in $NO_x$ emissions for later model year vehicles. Increases in NOx may result in more acetyl peroxy radical forming PAN rather than acetaldehyde. Recent EPA testing results, which have been included in the FRM scenarios, do not show these increases in $NO_x$ for later model year vehicles.[850] Our air quality modeling results may therefore underestimate the impacts of the renewable fuel volumes required by RFS2 on ambient concentrations of acetaldehyde.



**a** **b**

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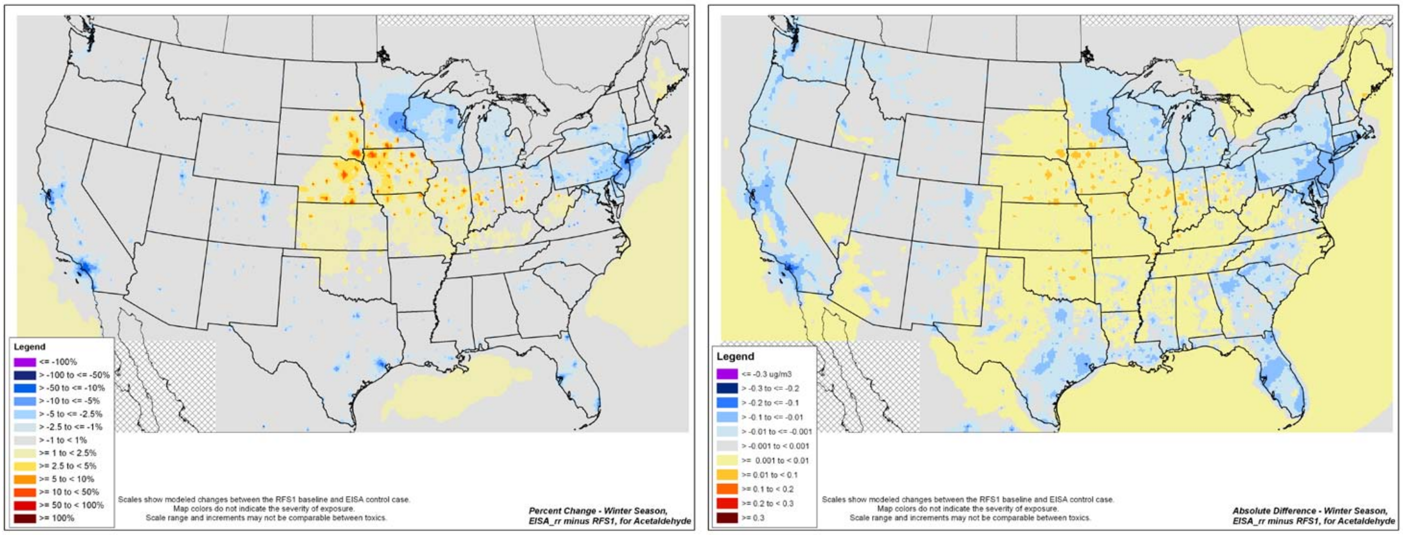
[CCCCCCCCC] EPAct Phase I, II, and III Testing: Comprehensive Gasoline Light-Duty Exhaust Fuel Effects Test Program to Cover Multiple Fuel Properties. EPA Contract: EPC-07-028EPA. Southwest Research Institute, San Antonio, TX. Phase III of the EPAct emission test program is scheduled for completion in 2010.

**Figure 3.4-15. Summer Changes in Acetaldehyde Ambient Concentrations Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022: (a) Percent Changes and (b) Absolute Changes (µg/m³)**

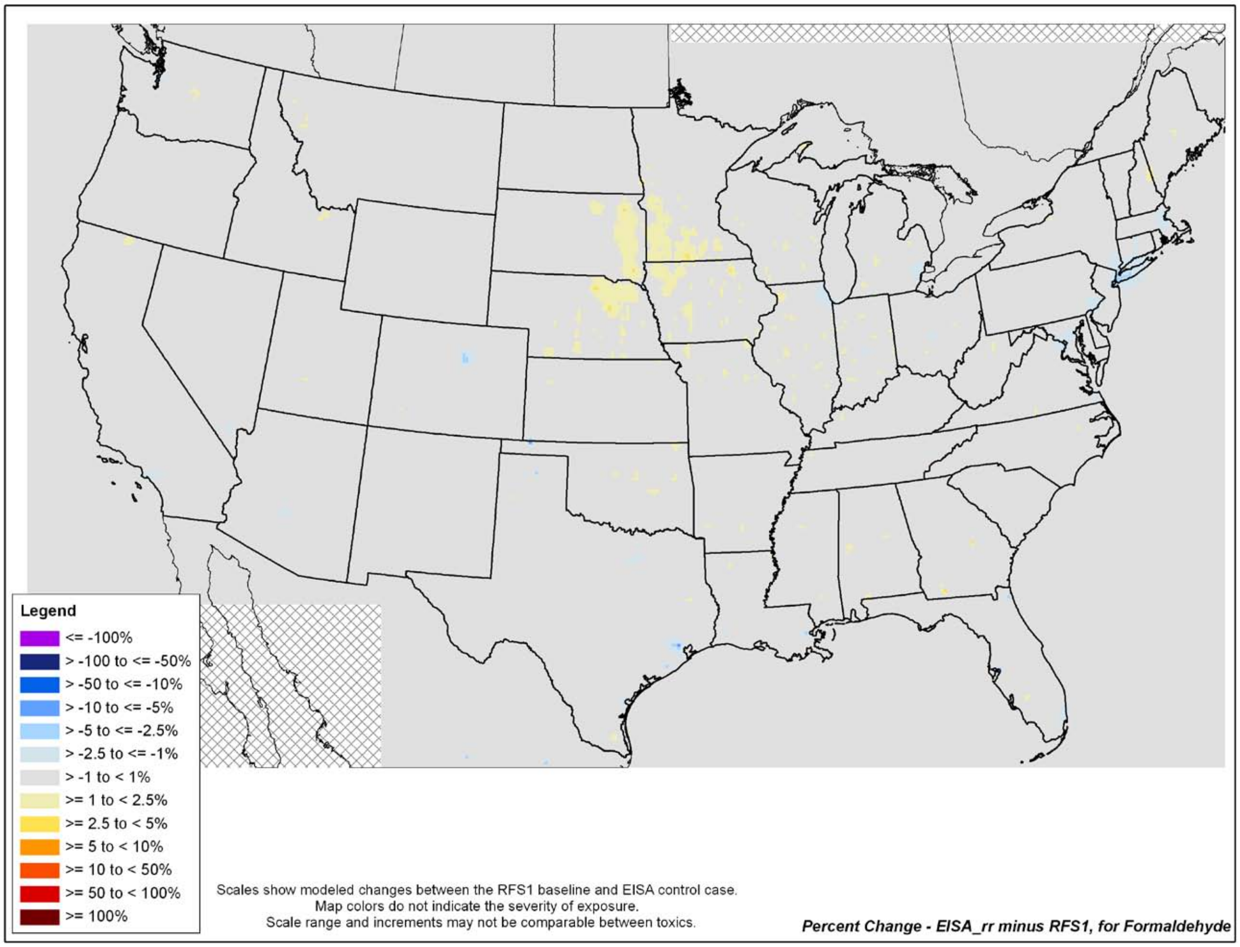


**a** **b**

**Figure 3.4-16. Winter Changes in Acetaldehyde Ambient Concentrations Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022: (a) Percent Changes and (b) Absolute Changes (µg/m³)**

### Formaldehyde

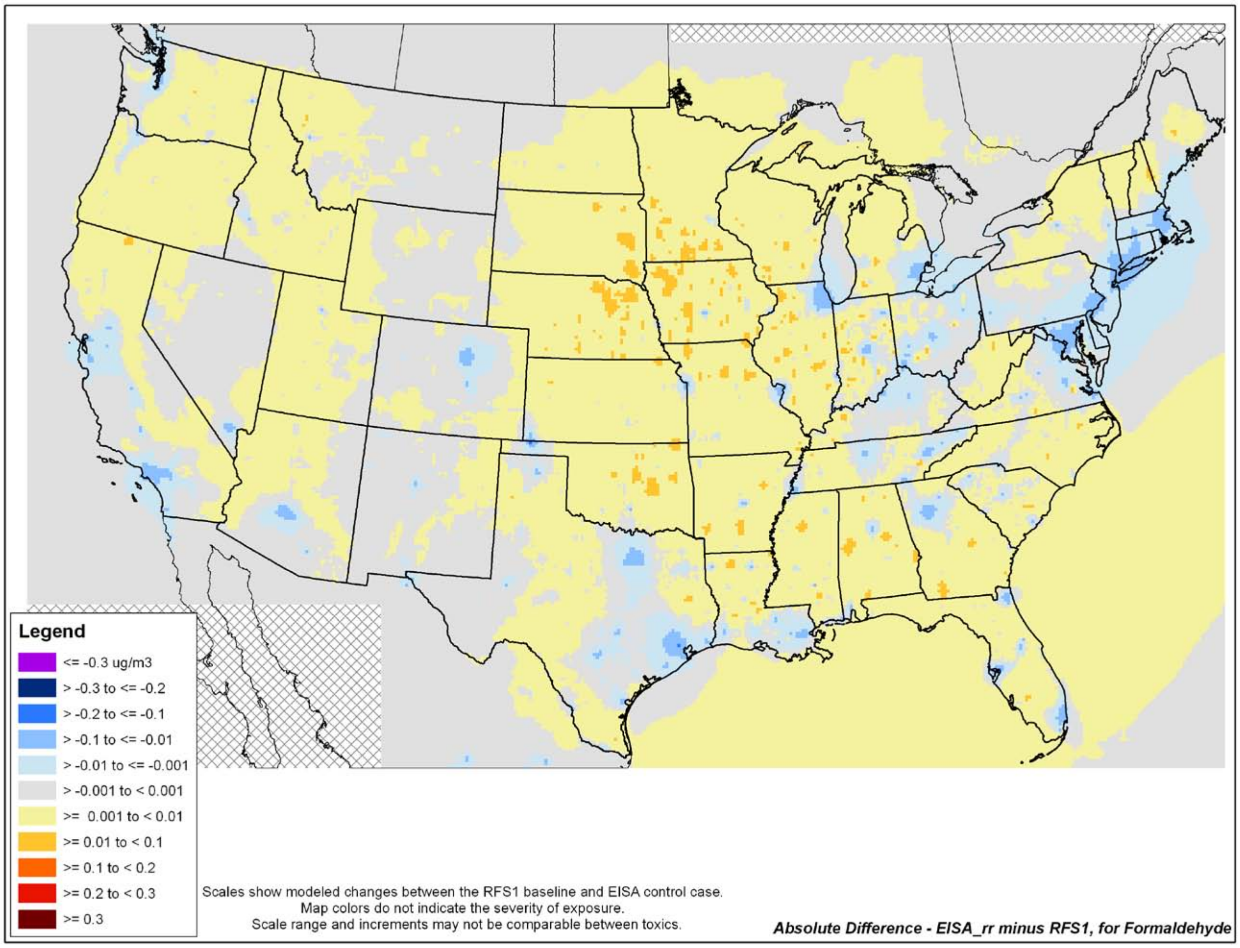
Our air quality modeling results do not show substantial impacts on ambient concentrations of formaldehyde from the renewable fuel volumes required by this rule. As shown in Figure 3.4-17, most of the U.S. experiences a 1% or less change in ambient formaldehyde concentrations. Decreases in ambient formaldehyde concentrations range between 1 and 5% in a few urban areas. Increases range between 1 and 2.5% in some rural areas associated with new ethanol plants; this result is due to increases in emissions of primary formaldehyde and formaldehyde precursors from the new ethanol plants. As discussed above, uncertainties in the placement of new ethanol plants limit the model's projected location of associated emission increases (Section 3.4.1.3). Figure 3.4-18 shows that absolute changes in ambient concentrations of formaldehyde are generally less than 0.1 µg/m³.



Scales show modeled changes between the RFS1 baseline and EISA control case.
Map colors do not indicate the severity of exposure.
Scale range and increments may not be comparable between toxics.

*Percent Change - EISA_rr minus RFS1, for Formaldehyde*

**Figure 3.4-17. Formaldehyde Annual Percent Change in Concentration Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022**



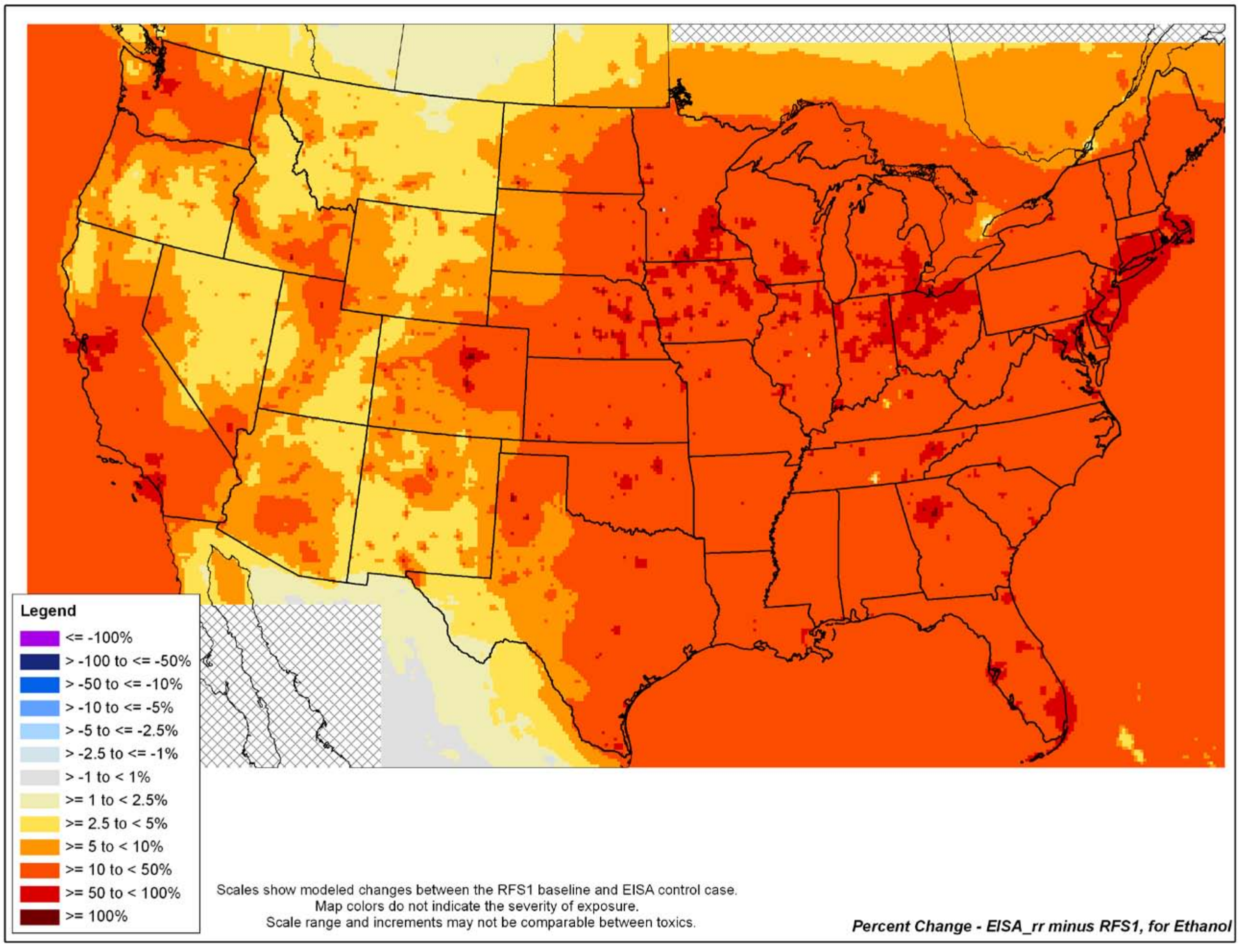
Scales show modeled changes between the RFS1 baseline and EISA control case.
Map colors do not indicate the severity of exposure.
Scale range and increments may not be comparable between toxics.

**Figure 3.4-18. Formaldehyde Annual Percent Changes in Ambient Concentrations Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022 (μg/m$^3$)**

### Ethanol

Our modeling projects that the renewable fuel volumes required by this rule will lead to significant nationwide increases in ambient ethanol concentrations. Increases ranging between 10 to 50% are seen across most of the country (Figure 3.4-19). The largest increases (more than 100%) occur in urban areas with high amounts of onroad emissions and in rural areas associated with new ethanol plants. Absolute increases in ambient ethanol concentrations are above 1.0 ppb in some urban areas (Figure 3.4-20). The location of these localized increases is limited by uncertainties in the placement of the new plants, as discussed in Section 3.4.1.3.

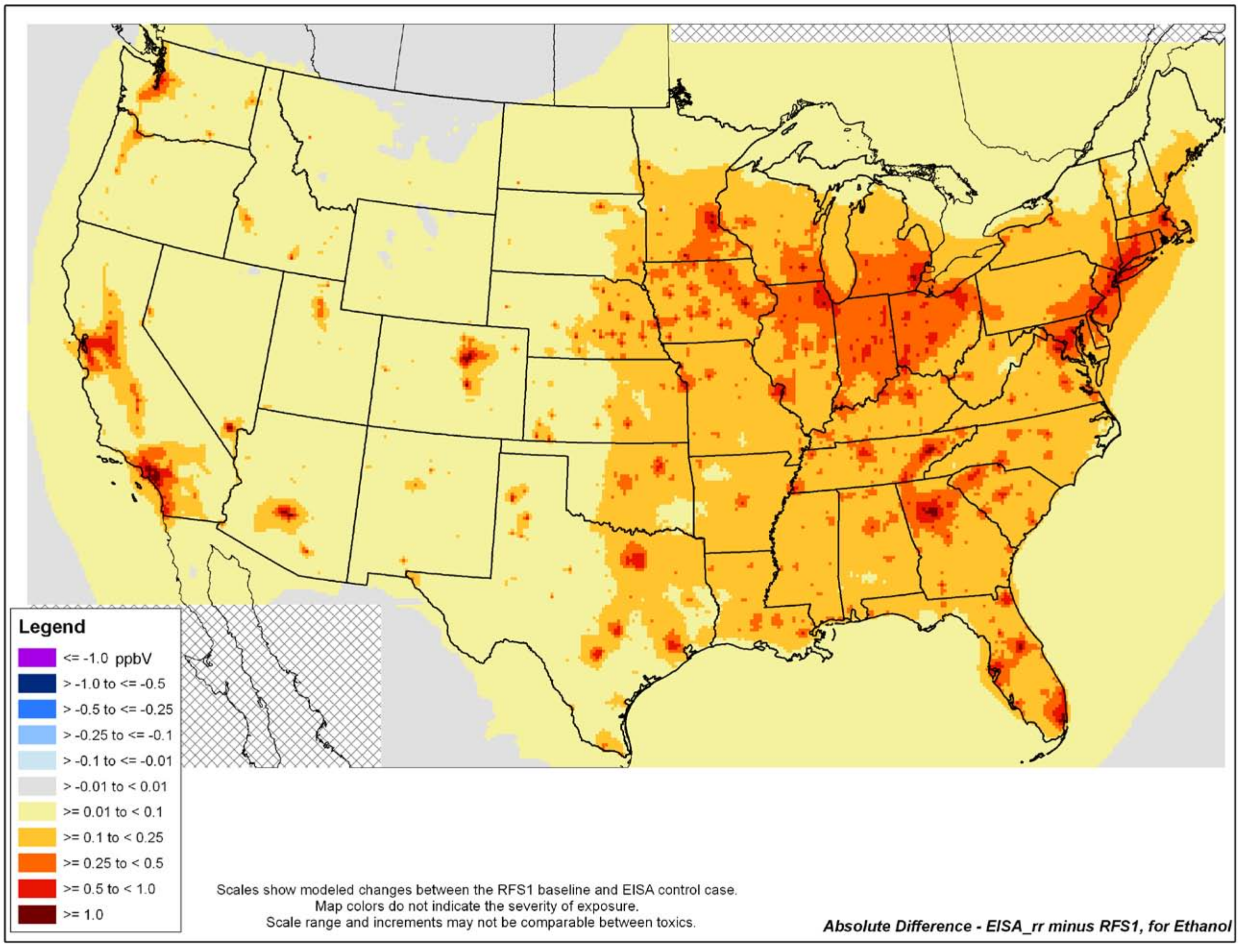
It should be noted here that these increases are overestimated because the speciated profile combination used for modeling nonroad emissions was misapplied. While sensitivity analyses suggest that the impact of this error was negligible for other pollutants, it resulted in overestimates of ethanol impacts by more than 10% across much of the modeling domain. For a detailed discussion, please refer to the emissions modeling TSD, found in the docket for this rule (EPA-HQ-OAR-2005-0161).



Scales show modeled changes between the RFS1 baseline and EISA control case.
Map colors do not indicate the severity of exposure.
Scale range and increments may not be comparable between toxics.

*Percent Change - EISA_rr minus RFS1, for Ethanol*

**Figure 3.4-19. Ethanol Annual Percent Changes Change in Concentration Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022**



Scales show modeled changes between the RFS1 baseline and EISA control case.
Map colors do not indicate the severity of exposure.
Scale range and increments may not be comparable between toxics.

*Absolute Difference - EISA_rr minus RFS1, for Ethanol*

**Figure 3.4-20. Ethanol Annual Absolute Changes in Ambient Concentrations Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022 (ppb)**

### Benzene

Our modeling projects that the renewable fuel volumes required by this rule will lead to small nationwide decreases in ambient benzene concentrations. As shown in Figure 3.4-21, decreases in ambient benzene concentrations range between 1 and 10% across most of the country and can be higher in a few urban areas. Absolute changes in ambient concentrations of benzene show reductions up to 0.2 µg/m³ (Figure 3.4-22).

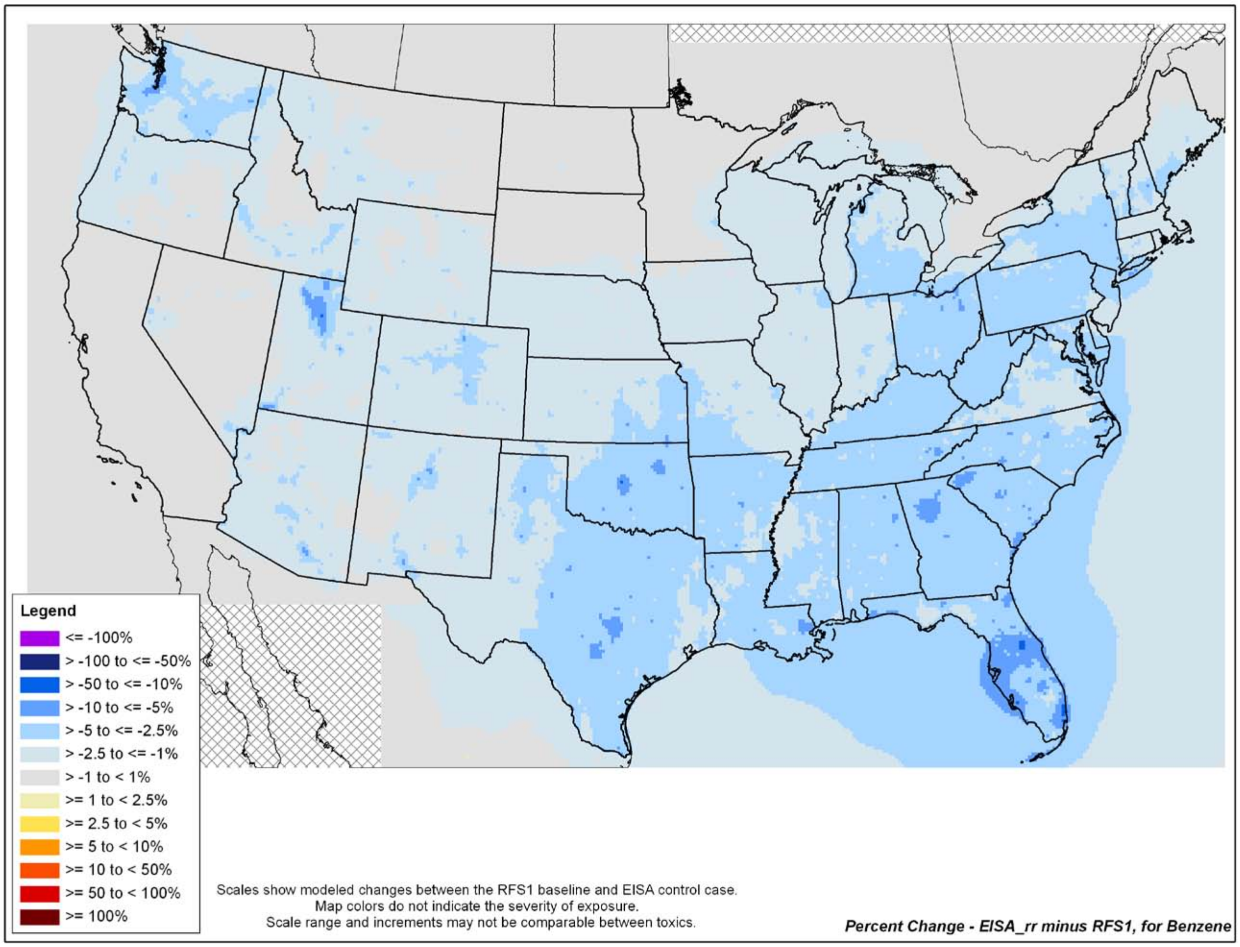
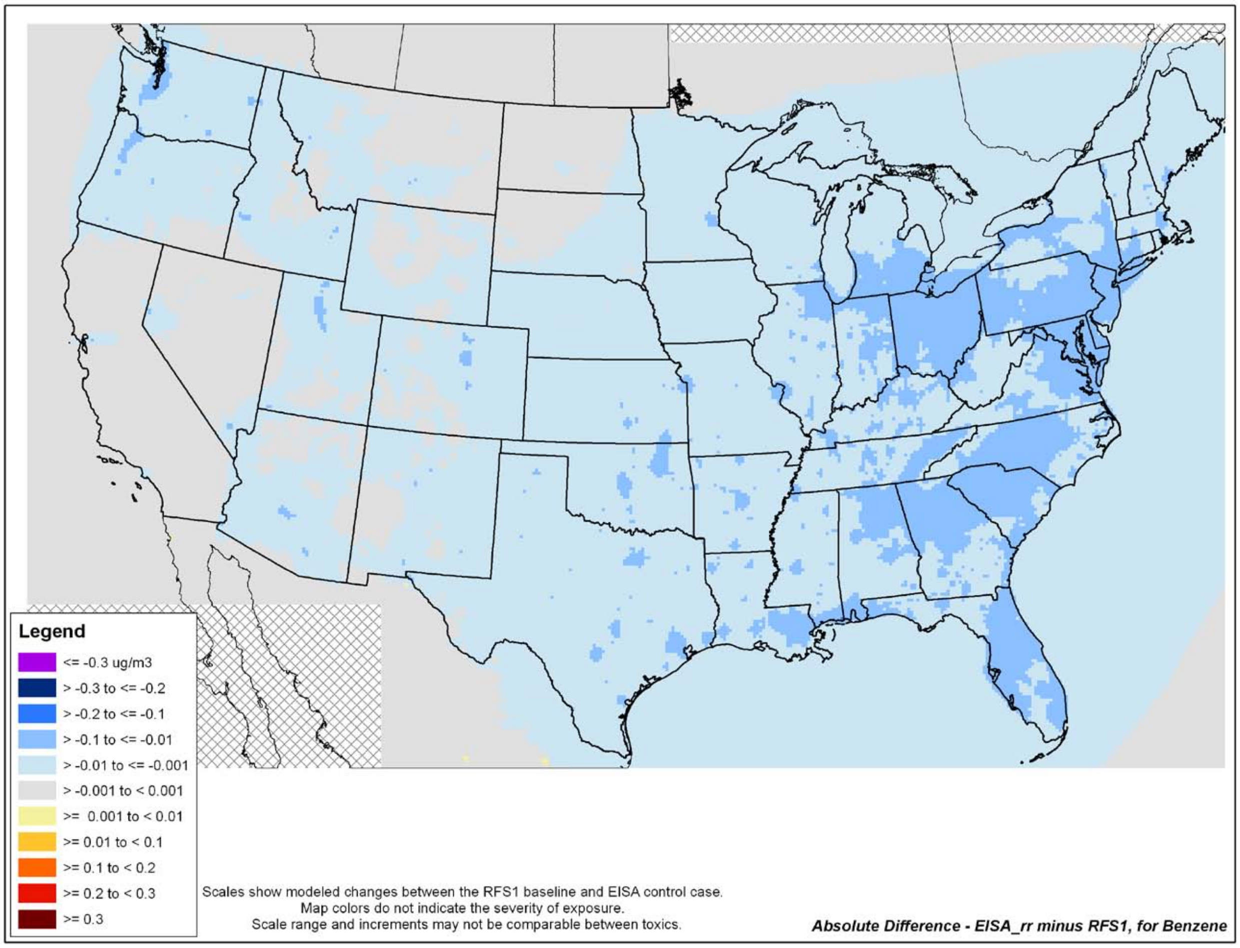


**Figure 3.4-21. Benzene Annual Percent Change in Concentration Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022**



Scales show modeled changes between the RFS1 baseline and EISA control case.
Map colors do not indicate the severity of exposure.
Scale range and increments may not be comparable between toxics.

**Figure 3.4-22. Benzene Annual Absolute Changes in Ambient Concentrations Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022 (µg/m³)**

### 1,3-Butadiene

The results of our air quality modeling show small increases and decreases in ambient concentrations of 1,3-butadiene in parts of the U.S. as a result of the renewable fuel volumes required this rule. Generally, decreases occur in some southern areas of the country and increases occur in some northern areas and areas with high altitudes (Figure 3.4-23). Percent changes in 1,3-butadiene concentrations are over 50% in several areas; but the changes in absolute concentrations of ambient 1,3-butadiene are generally less than 0.005 µg/m³ (Figure 3.4-24). Annual increases in ambient concentrations of 1,3-butadiene are driven by wintertime rather than summertime changes (Figures 3.4-25 and 3.4-26). These increases appear in rural areas with cold winters and low ambient levels but high contributions of emissions from snowmobiles, and a major reason for this modeled increase may be deficiencies in available emissions test data used to estimate snowmobile 1,3-butadiene emission inventories. These data were based on tests using only three engines, which showed significantly higher 1,3-butadiene emissions with 10% ethanol. However, they may not have been representative of real-world response of snowmobile engines to ethanol.

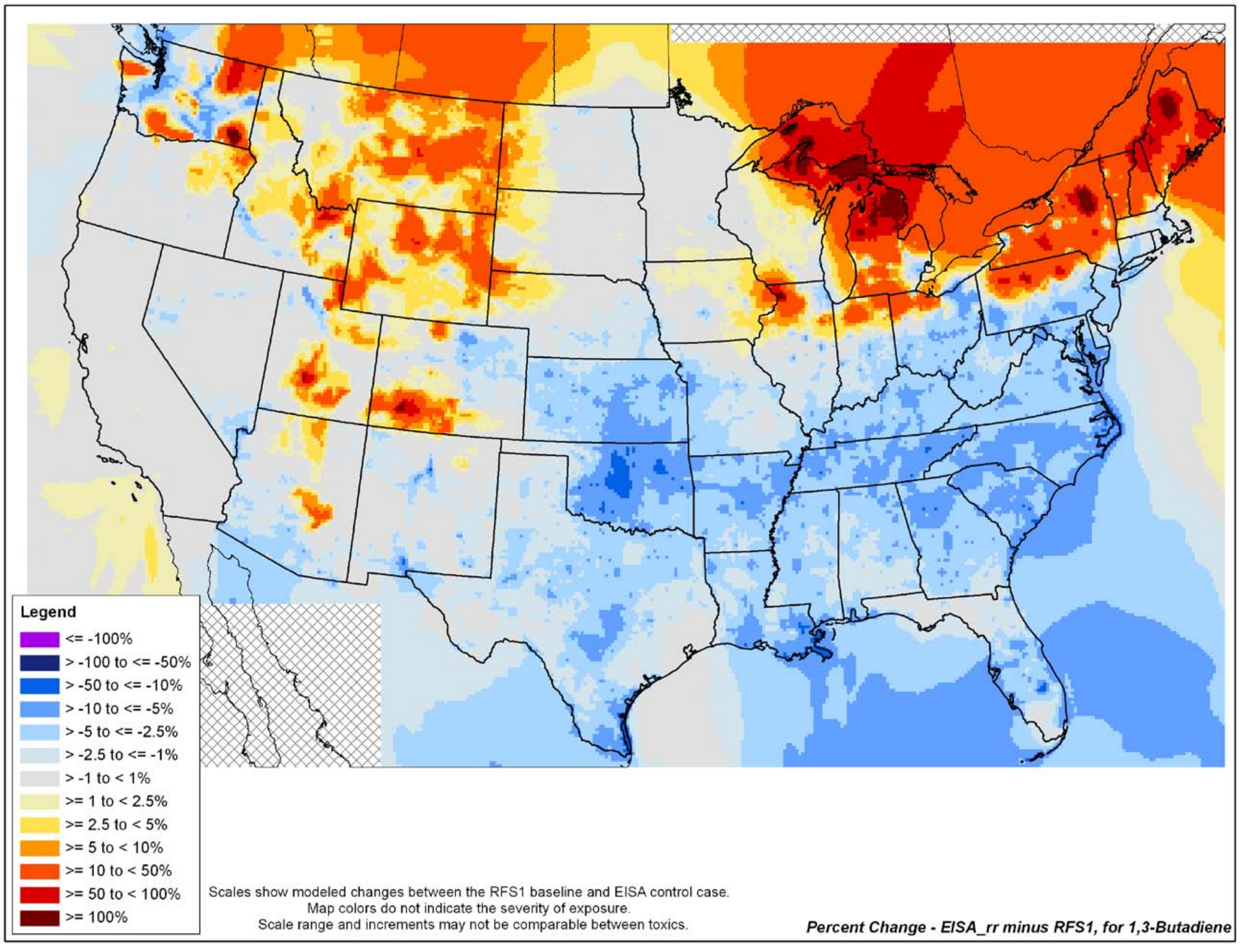


**Figure 3.4-23. 1,3-Butadiene Annual Percent Change in Concentration Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022**

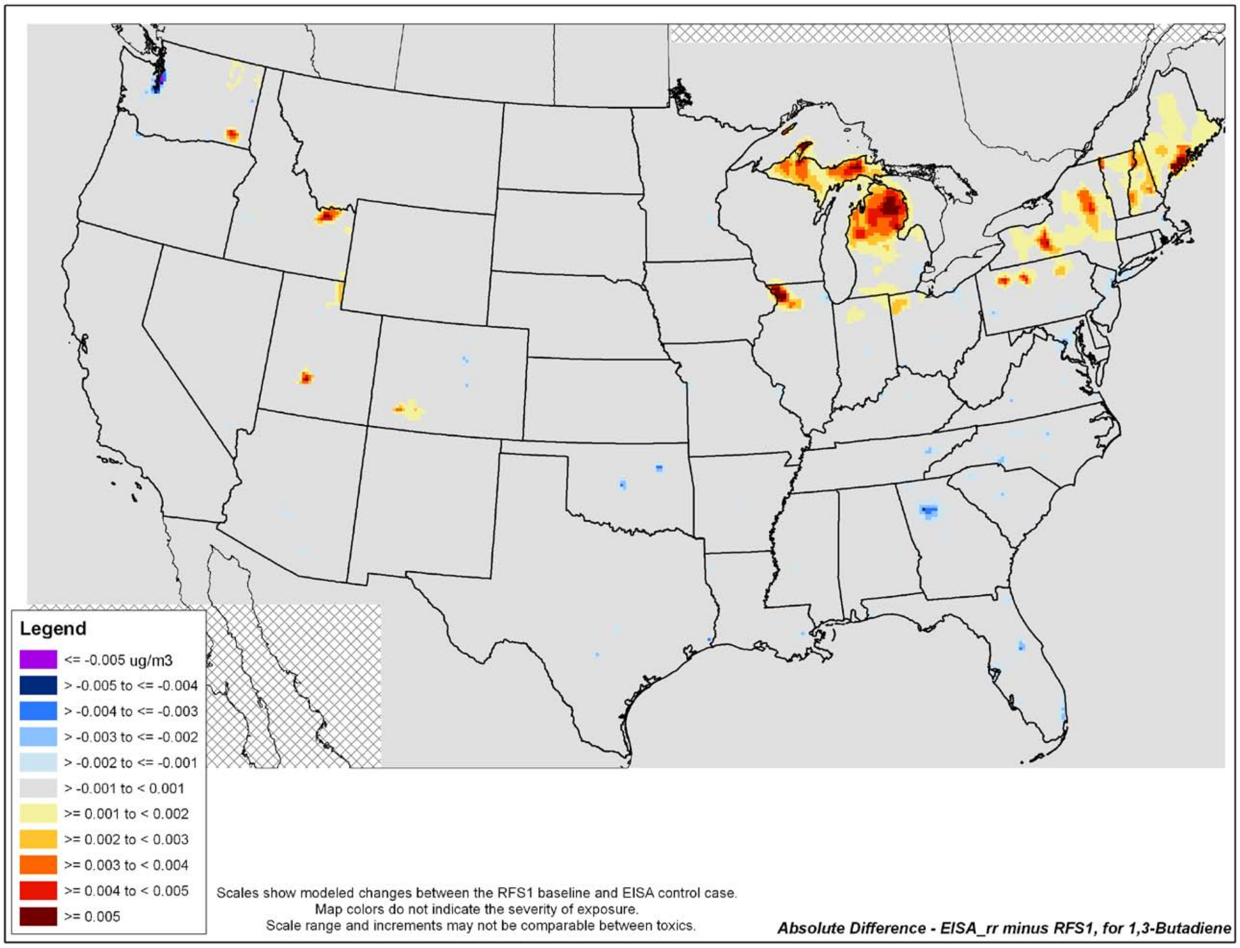
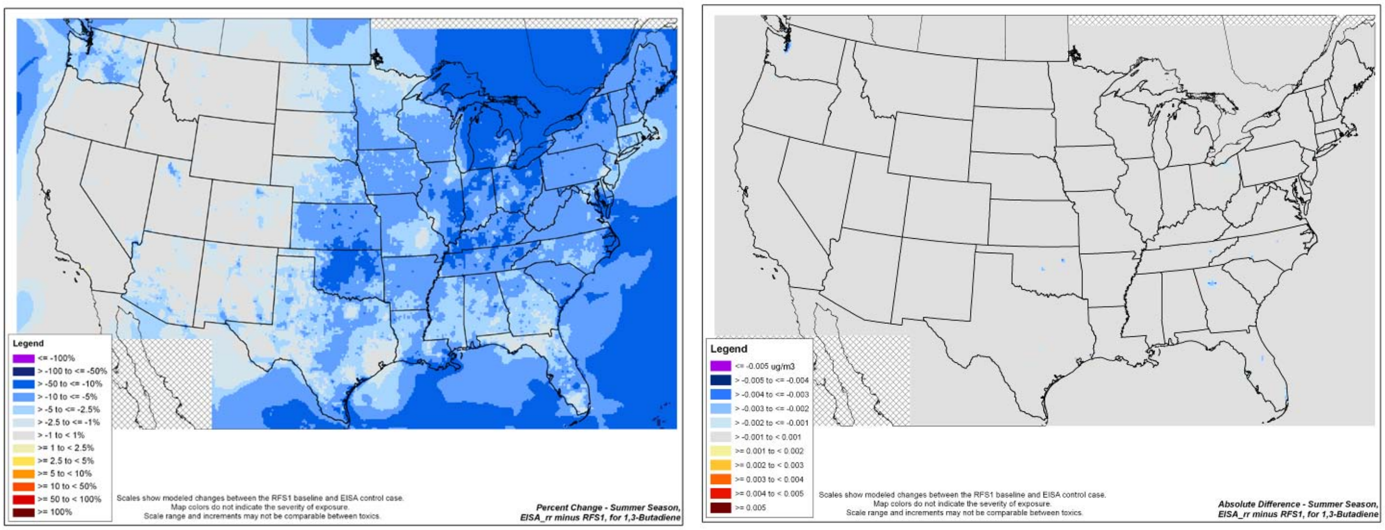
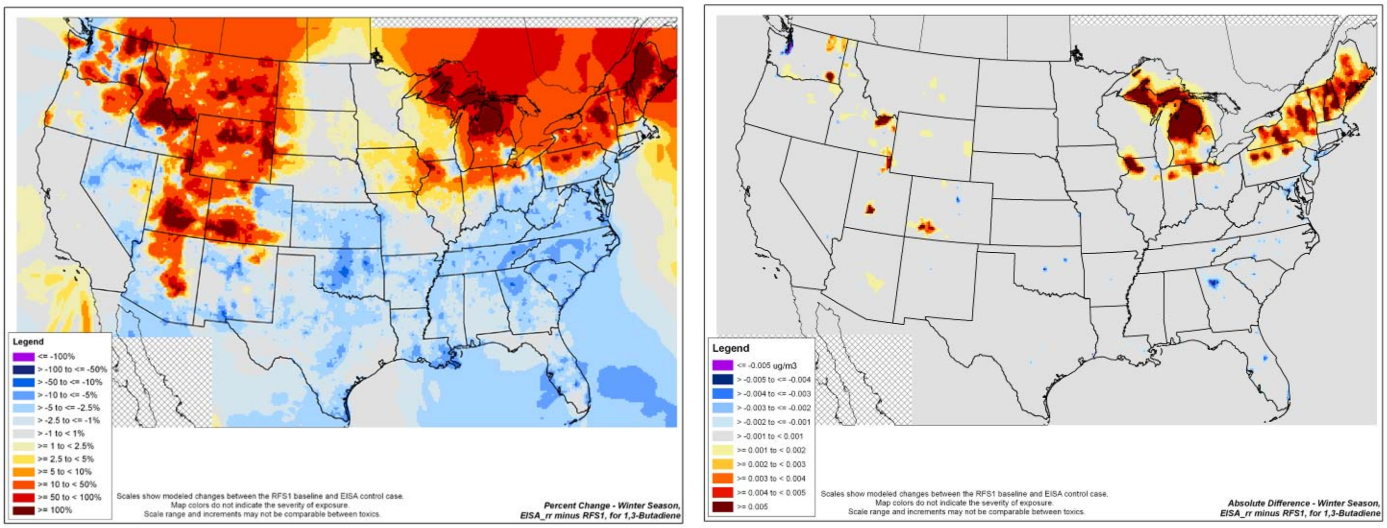


**Figure 3.4-24. 1,3-Butadiene Annual Absolute Changes in Ambient Concentrations Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022 (µg/m³)**



a b

**Figure 3.4-25. Summer Changes in 1,3-Butadiene Ambient Concentrations Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022: (a) Percent Changes and (b) Absolute Changes (µg/m³)**



a b

**Figure 3.4-26. Winter Changes in 1,3-Butadiene Ambient Concentrations Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022: (a) Percent Changes and (b) Absolute Changes (µg/m³)**

## Acrolein

Our air quality modeling shows small regional increases and decreases in ambient concentrations of acrolein as a result of the renewable fuel volumes required by this rule. As shown in Figure 3.4-27, decreases in acrolein concentrations occur in some eastern and southern parts of the U.S. and increases occur in some northern areas and areas associated with new ethanol plants. Figure 3.4-28 indicates that changes in absolute ambient concentrations of acrolein are between ± 0.001 µg/m³ with the exception of the increases associated with new ethanol plants. These increases can be up to and above 0.005 µg/m³ with percent changes above 50% and are due to increases in emissions of acrolein from the new plants. As discussed in Section 3.4.1.3, uncertainties in the placement of new ethanol plants limit the model's projected location of associated emission increases. Ambient acrolein increases in upper Michigan, Canada, the Northeast, and the Rocky Mountain region are driven by wintertime changes (Figures 3.4-29 and 3.4-30), and occur in the same areas of the country that have wintertime rather than summertime increases in ambient 1,3-butadiene. 1,3-butadiene is a precursor to acrolein, and these increases are likely associated with the same emission inventory issues in areas of high snowmobile usage seen for 1,3-butadiene, as described above.

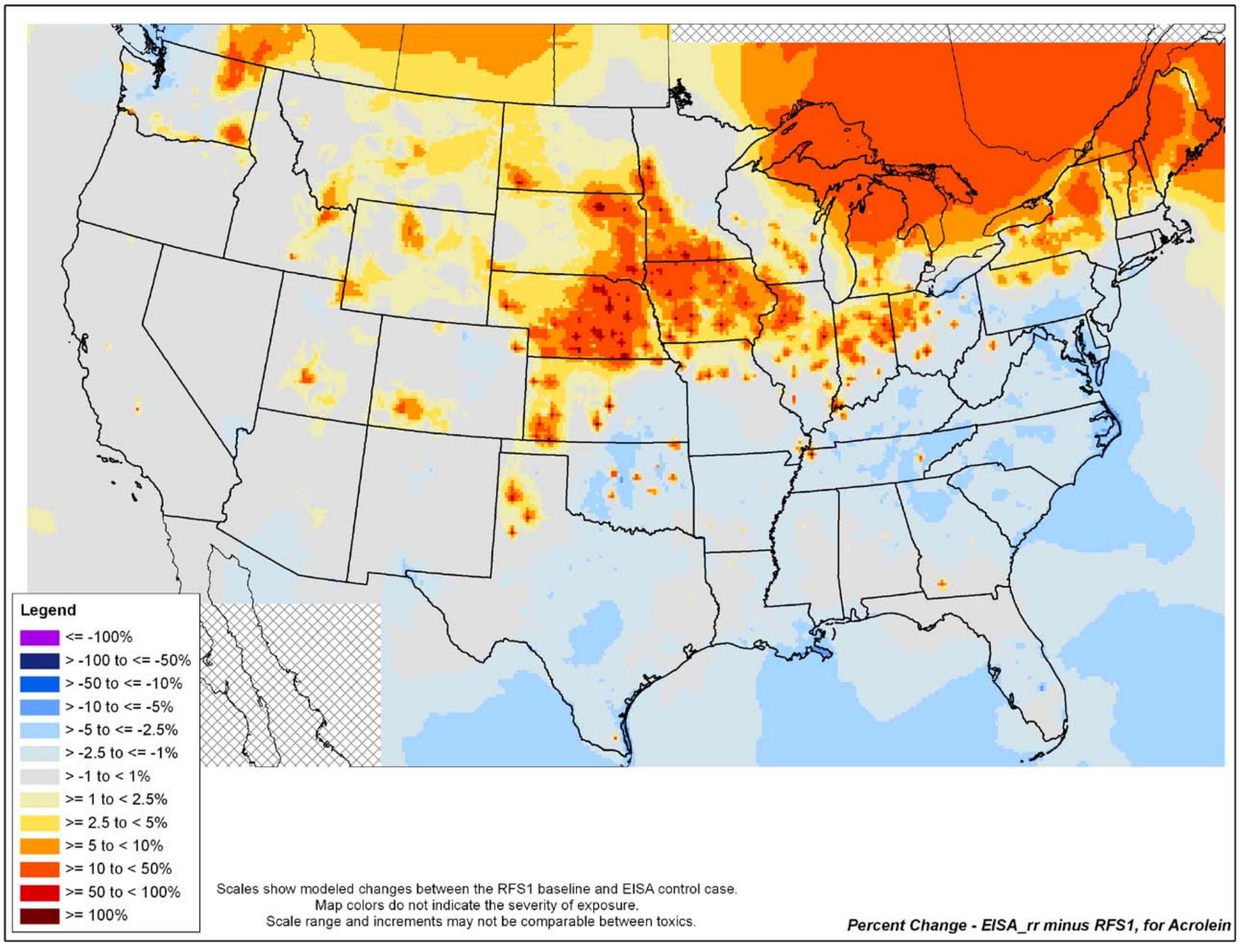


**Figure 3.4-27. Acrolein Annual Percent Changes Change in Concentration Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022**

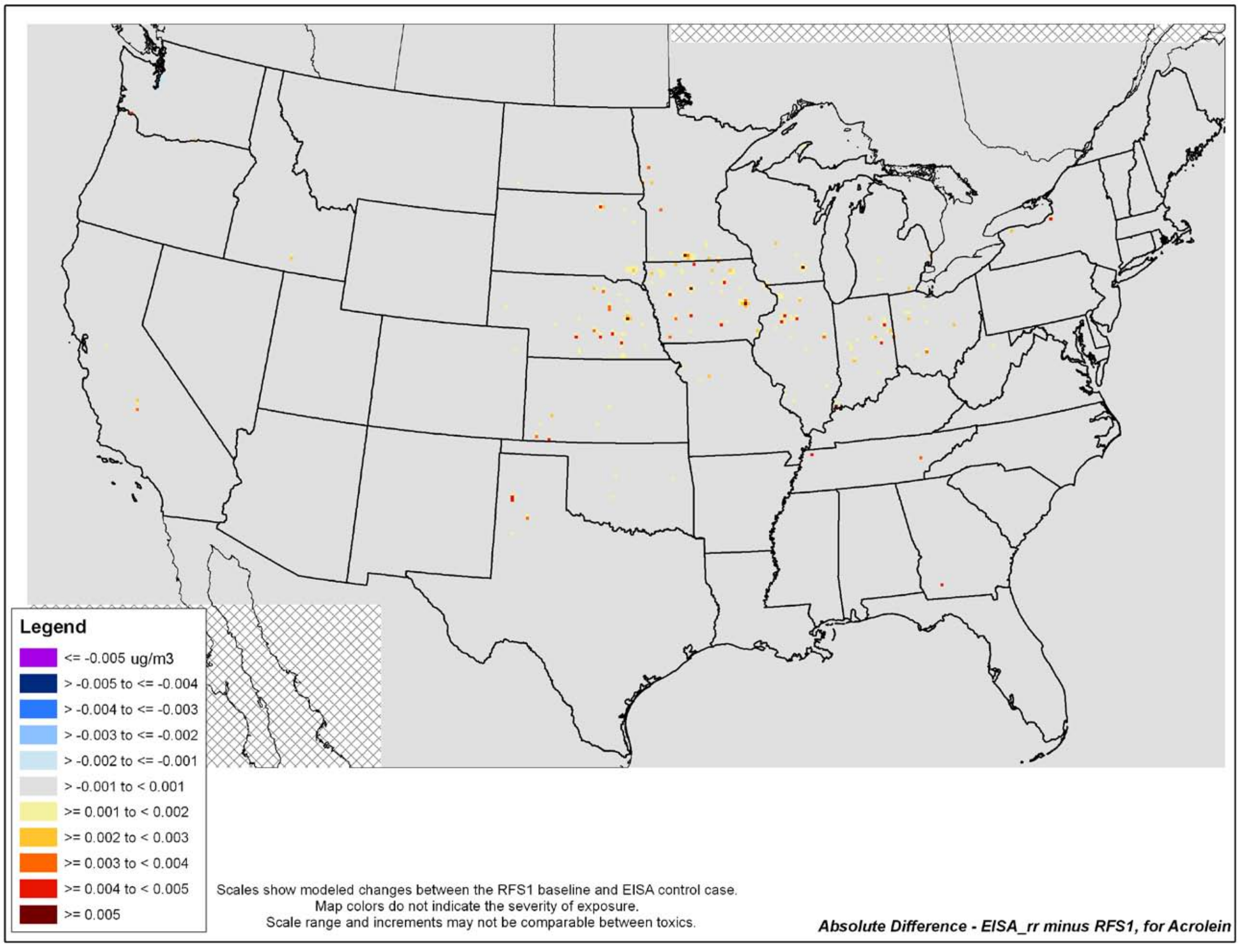
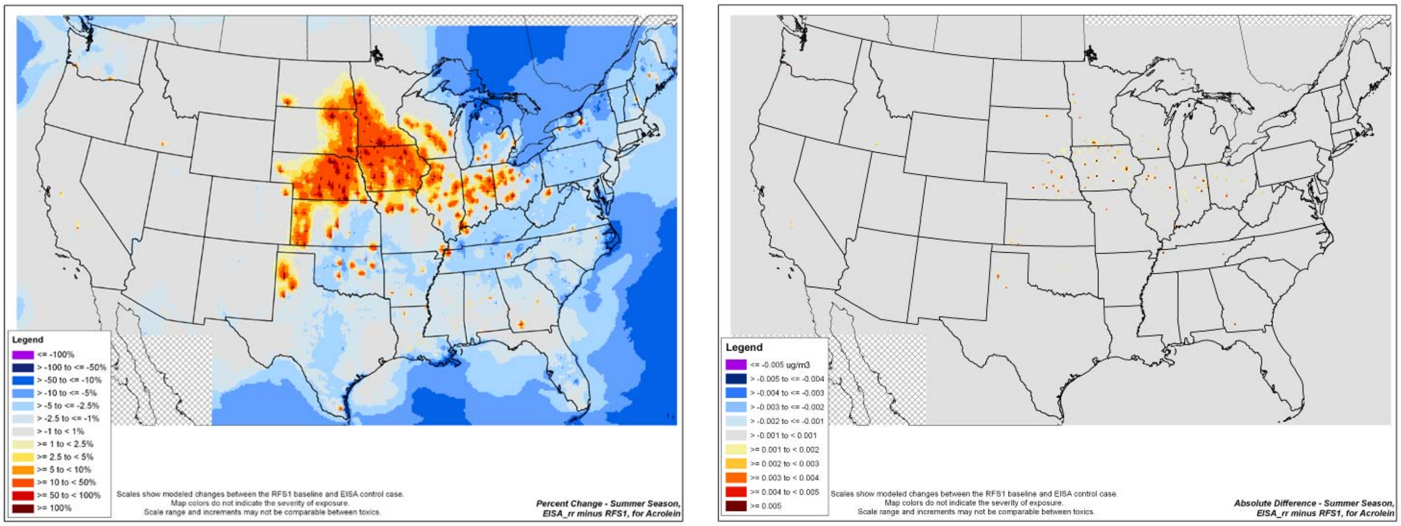


**Figure 3.4-28. Acrolein Annual Absolute Changes in Ambient Concentrations Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022 (µg/m$^3$)**



Scales show modeled changes between the RFS1 baseline and EISA control case.
Map colors do not indicate the severity of exposure.
Scale range and increments may not be comparable between toxics.

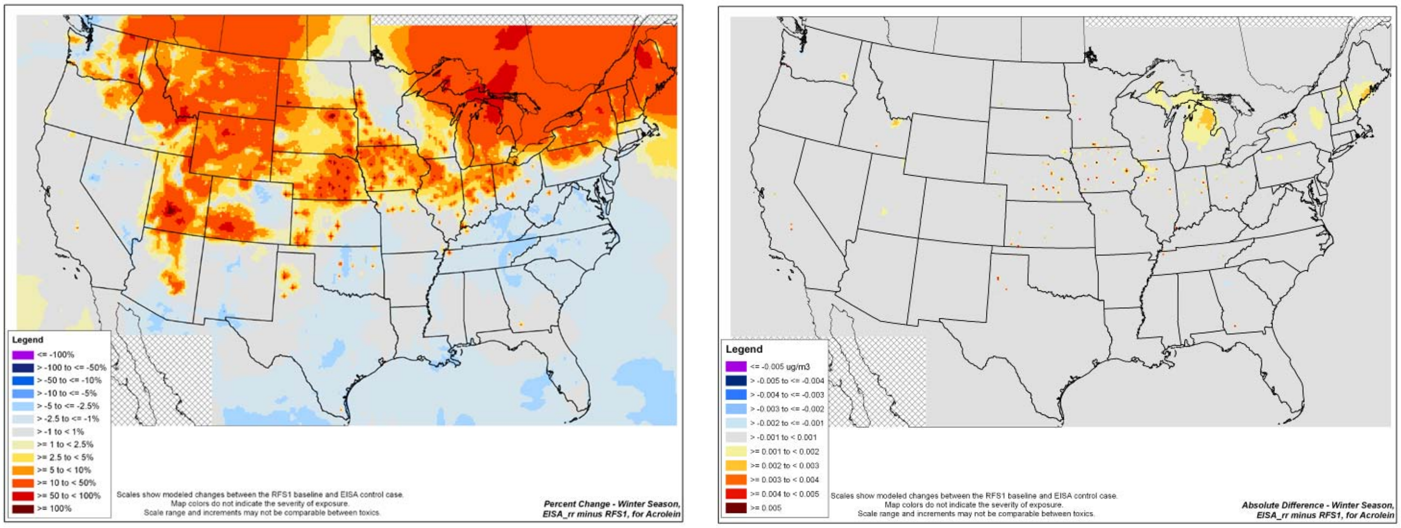
*Percent Change - Summer Season,
EISA_rr minus RFS1, for Acrolein*

Scales show modeled changes between the RFS1 baseline and EISA control case.
Map colors do not indicate the severity of exposure.
Scale range and increments may not be comparable between toxics.

*Absolute Difference - Summer Season,
EISA_rr minus RFS1, for Acrolein*

**a** **b**

**Figure 3.4-29. Summer Changes in Acrolein Ambient Concentrations Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022: (a) Percent Changes and (b) Absolute Changes (µg/m$^3$)**



Scales show modeled changes between the RFS1 baseline and EISA control case.
Map colors do not indicate the severity of exposure.
Scale range and increments may not be comparable between toxics.

*Percent Change - Winter Season,
EISA_rr minus RFS1, for Acrolein*

Scales show modeled changes between the RFS1 baseline and EISA control case.
Map colors do not indicate the severity of exposure.
Scale range and increments may not be comparable between toxics.

*Absolute Difference - Winter Season,
EISA_rr minus RFS1, for Acrolein*

**a** **b**

**Figure 3.4-30. Winter Changes in Acrolein Ambient Concentrations Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022: (a) Percent Changes and (b) Absolute Changes (µg/m$^3$)**

**Population Metrics**

To assess the impact of projected changes in air quality with increased renewable fuel use, we developed population metrics that show population experiencing increases and decreases in annual ambient concentrations across the modeled air toxics. Figure 3.4-31 below illustrates the number of people impacted by changes of various magnitudes in annual ambient concentrations with the renewable fuel volumes required by RFS2 in 2022, as compared to the RFS1 mandate reference case. For ambient concentrations of ethanol, over 98% of the population (334,730,202 people) experiences an increase greater than or equal to 10%. For the other modeled air toxics, more than 90% of the population (greater than 305,658,000 people) will experience a change in ambient concentration of ±1%. For acrolein, 9.9% of the population (33,354,866 people) will live in areas with an increase in ambient concentrations ranging from 1 to 50%; 0.13% (439,535 people) of the population experiences an increase greater than 50%. For 1,3-butadiene, 5.9% of the population (20,171,533 people) experiences a 1 to 50% increase in ambient concentrations, and 0.33% (1,135,806 people) of the population experiences an increase greater than 50%. The percentage of the population living in areas with increases in ambient concentrations of acetaldehyde and formaldehyde are as follows: 0.30% of the population (1,007,009 people) experiences acetaldehyde increases between 1 and 10%, and 0.48% of the population (1,642,944 people) experiences formaldehyde increases between 1 and 2.5%.

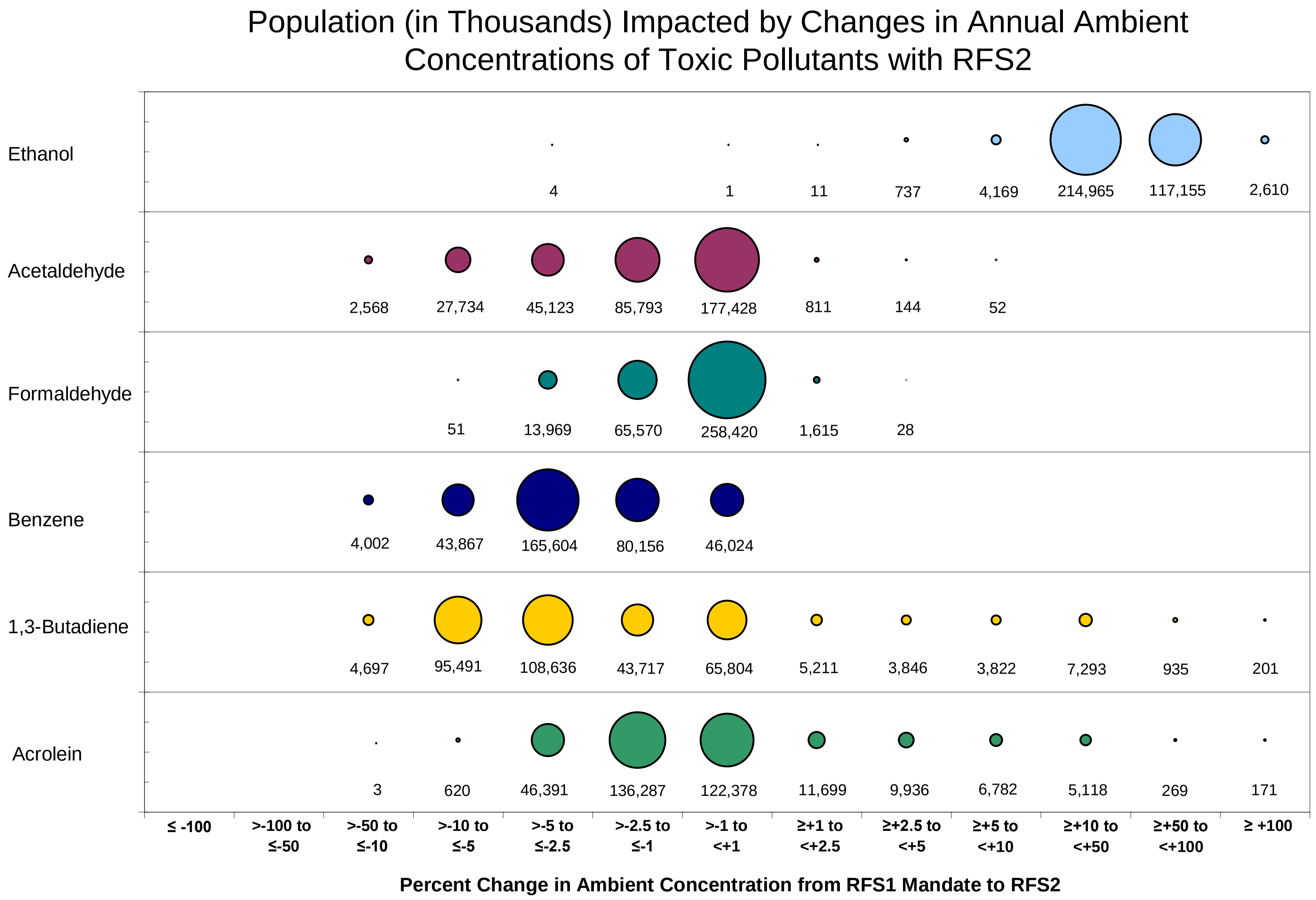


**Figure 3.4-31. Number of People Impacted by Changes in Annual Ambient Concentrations or Toxic Pollutants by Percent Change Brackets, RFS 1 Mandate Reference Case Compared to the RFS2 Control Case**

The population exposed to average ambient concentrations of air toxics above and below reference concentrations for noncancer health effects in 2022 is presented for the two reference cases in Table 3.4-4 below. Reference concentration (RfC) values presented in this table are the same as those used in the 2002 NATA.[851] At present, no RfC exists for ethanol; EPA is conducting an IRIS assessment for this air toxic. The RfC is an estimate, with uncertainty spanning perhaps an order of magnitude, of an inhalation exposure to the human population (including sensitive subgroups) that is likely to be without appreciable risks of deleterious effects during a lifetime. Exposures to levels above the RfC do not necessarily suggest a likelihood of adverse health effects, because many RfCs incorporate protective assumptions in the face of uncertainty. Exposures above the RfC can best be interpreted as indicating that a potential exists for adverse health effects. In addition, average population exposures could be lower or higher than the modeled ambient concentrations.

Table 3.4-4 shows that population-weighted nationwide annual average concentrations for the modeled air toxics are below the RfC values for both the RFS1 reference case and the AEO 2007 reference case. However, the population-weighted nationwide annual average for acrolein is very close to the RfC. Table 3.4-4 also shows the national population that is exposed to ambient concentrations above and below the RfC for the modeled air toxics. In both reference cases, over 94 million people are exposed to ambient concentrations above the RfC for acrolein but the national population is exposed to ambient concentrations below the RfC for acetaldehyde, benzene, 1,3-butadiene, and formaldehyde.

**Table 3.4-4. Populations Exposed to Ambient Concentrations of Air Toxics above and below Reference Concentrations for Noncancer Health Effects in 2022 without RFS2**

| | **CAS No.** | **Population-weighted Concentration (Nationwide Annual Average in μg/m³)** | | **RfC (μg/m³)** | **National Population above RfC (Annual Average)** | | **National Population below RfC (Annual Average)** | |
|---|---|---|---|---|---|---|---|---|
| | | RFS1 Mandate | AEO 2007 | | RFS1 Mandate | AEO 2007 | RFS1 Mandate | AEO 2007 |
| Acetaldehyde | 75070 | 1.618 | 1.613 | 9 | 0 | 0 | 339,652,451 | 339,652,451 |
| Acrolein | 107028 | 0.018 | 0.017 | 0.02 | 95,059,422 | 94,087,145 | 244,593,029 | 245,565,306 |
| Benzene | 71432 | 0.535 | 0.527 | 30 | 0 | 0 | 339,652,451 | 339,652,451 |
| 1,3-Butadiene | 106990 | 0.023 | 0.023 | 2 | 0 | 0 | 339,652,451 | 339,652,451 |
| Ethanol[a] | 64175 | 1.039 | 1.112 | - | - | - | - | - |
| Formaldehyde | 50000 | 1.558 | 1.555 | 9.8 | 0 | 0 | 339,652,451 | 339,652,451 |

Table 3.4-5 shows changes in the population exposed to average ambient concentrations of air toxics above and below reference concentrations for noncancer health effects in 2022 that are projected to occur with increased renewable fuel use as required by RFS2. Differences in population-weighted annual average concentrations between the RFS2 control case and the RFS1 mandate reference case are small, and ethanol is the only compound shown to increase with RFS2 fuel volumes. Table 3.4-5 also shows that the renewable fuel volumes required by RFS2 do not result in any increases in the number of people exposed to ambient concentrations above

the RfC values. The results indicate there may be a reduction in the number of people exposed to ambient concentrations of acrolein with RFS2 fuel volumes.

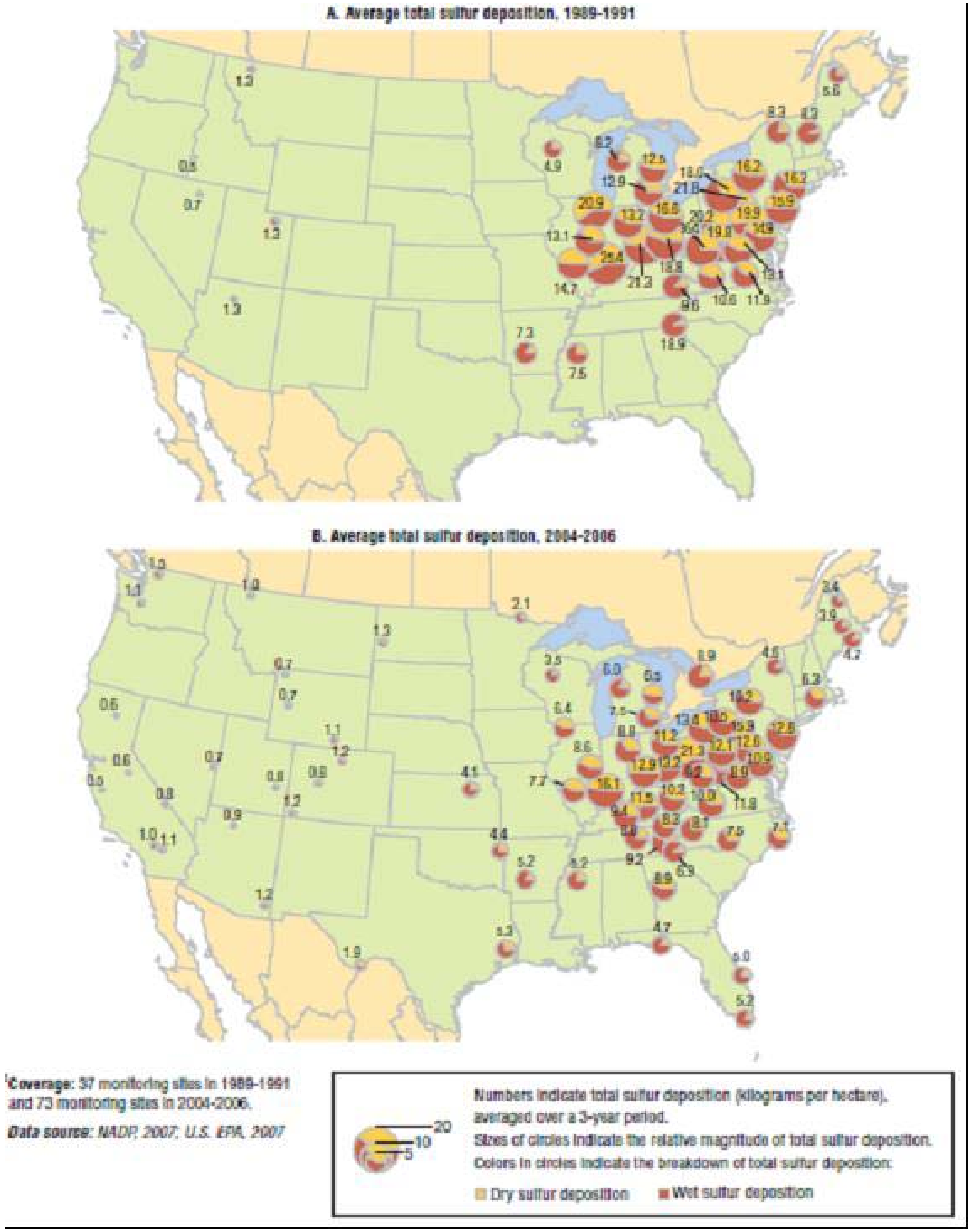
**Table 3.4-5. Populations Exposed to Ambient Concentrations of Air Toxics above and below Reference Concentrations for Noncancer Health Effects in 2022 with RFS2**

| | **CAS No.** | **Population-weighted Concentration (Annual Average in µg/m³)** | | | **National Population above RfC (Annual Average)** | | |
|---|---|---|---|---|---|---|---|
| | | RFS2 | RFS1 Mandate | Diff. | RFS2 | RFS1 Mandate | Diff. |
| Acetaldehyde | 75070 | 1.590 | 1.618 | -0.028 | 0 | 0 | 0 |
| Acrolein | 107028 | 0.017 | 0.018 | -0.001 | 92,452,143 | 95,059,422 | -2,607,279 |
| Benzene | 71432 | 0.520 | 0.535 | -0.015 | 0 | 0 | 0 |
| 1,3-Butadiene | 106990 | 0.022 | 0.023 | -0.001 | 0 | 0 | 0 |
| Ethanol | 64175 | 1.521 | 1.039 | 0.482 | - | - | - |
| Formaldehyde | 50000 | 1.549 | 1.558 | -0.009 | 0 | 0 | 0 |

### 3.4.2.2 Deposition of Nitrogen and Sulfur

#### 3.4.2.2.1 Current Levels of Nitrogen and Sulfur Deposition

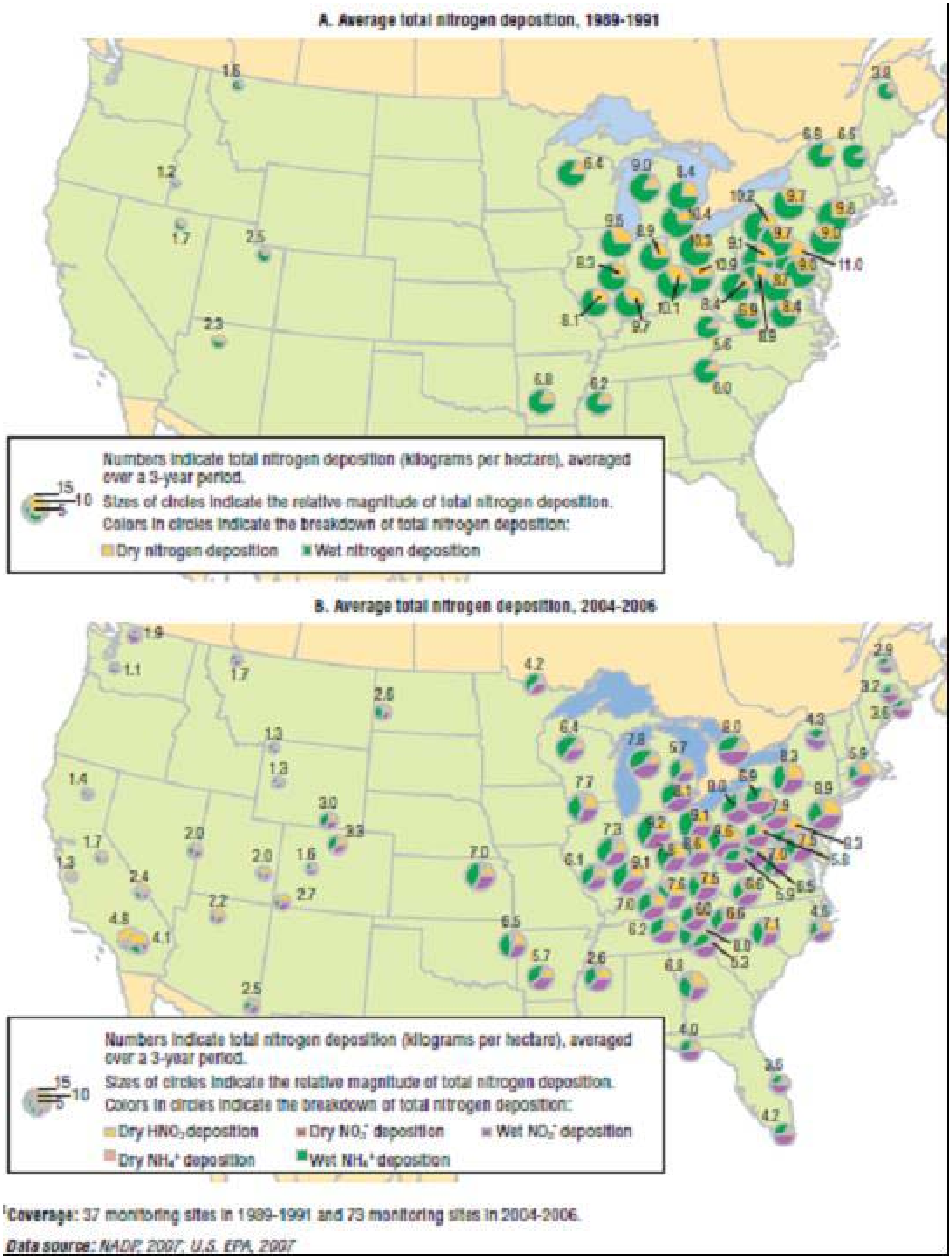
Over the past two decades, the EPA has undertaken numerous efforts to reduce nitrogen and sulfur deposition across the U.S. Analyses of long-term monitoring data for the U.S. show that deposition of both nitrogen and sulfur compounds has decreased over the last 17 years although many areas continue to be negatively impacted by deposition. Deposition of inorganic nitrogen and sulfur species routinely measured in the U.S. between 2004 and 2006 were as high as 9.6 kilograms of nitrogen per hectare per year (kg N/ha/yr) and 21.3 kilograms of sulfur per hectare per year (kg S/ha/yr). Figures 3.4-32 and 3.4-33 show that annual total deposition (the sum of wet and dry deposition) decreased between 1989-1999 and 2004-2006 due to sulfur and $NO_X$ controls on power plants, motor vehicles and fuels in the U.S. The data show that reductions were more substantial for sulfur compounds than for nitrogen compounds. These numbers are generated by the U.S. national monitoring network and they likely underestimate nitrogen deposition because neither ammonia nor organic nitrogen is measured. In the eastern U.S., where data are most abundant, total sulfur deposition decreased by about 36 % between 1990 and 2005, while total nitrogen deposition decreased by 19% over the same time frame.[852]



**Coverage:** 37 monitoring sites in 1989-1991 and 73 monitoring sites in 2004-2006.

**Data source:** *NADP, 2007; U.S. EPA, 2007*

**Figure 3.4-32. Total Sulfur Deposition in the Contiguous U.S., 1989-1991 and 2004 -2006**



[1]**Coverage:** 37 monitoring sites in 1989-1991 and 73 monitoring sites in 2004-2006.

***Data source:*** *NADP, 2007; U.S. EPA, 2007*

**Figure 3.4-33. Total Nitrogen Deposition in the Contiguous U.S., 1989-1991 and 2004-2006**

#### 3.4.2.2.2 Projected Levels of Nitrogen and Sulfur Deposition

Our air quality modeling does not show substantial overall nationwide impacts on the annual total sulfur and nitrogen deposition occurring across the U.S. as a result of increased renewable fuel volumes required by this rule. Figure 3.4-34 shows that when compared to the RFS1 mandate reference case, the RFS2 renewable fuel volumes will result in nearly the entire eastern half of the United States seeing nitrogen deposition increases ranging from 0.5% to more than 2%. The largest increases will occur in the states of Illinois, Michigan, Indiana, Wisconsin, and Missouri, with large portions of each of these states seeing nitrogen deposition increases of more than 2%. The Pacific Northwest will also experience increases in nitrogen of 0.5% to more than 2%. Figure 3.4-35 shows that when compared to the AEO 2007 reference case, the changes in nitrogen deposition as a result of the RFS2 renewable fuel volumes are more limited. The eastern half of the United States will still see nitrogen deposition increases ranging from 0.5% to more than 2%; however, the size of the area with these changes will be smaller. Increases of more than 2% will primarily occur only in Illinois, Indiana, Michigan, and Missouri. Fewer areas in the Pacific Northwest will have increases in nitrogen deposition when compared to the AEO 2007 reference case. In both the RFS1 mandate and AEO 2007 reference cases the Mountain West and Southwest will see only minimal changes in nitrogen deposition, ranging from decreases of less than 0.5% to increases of less than 0.5%. A few areas in Minnesota and western Kansas would experience reductions of nitrogen up to 2%.

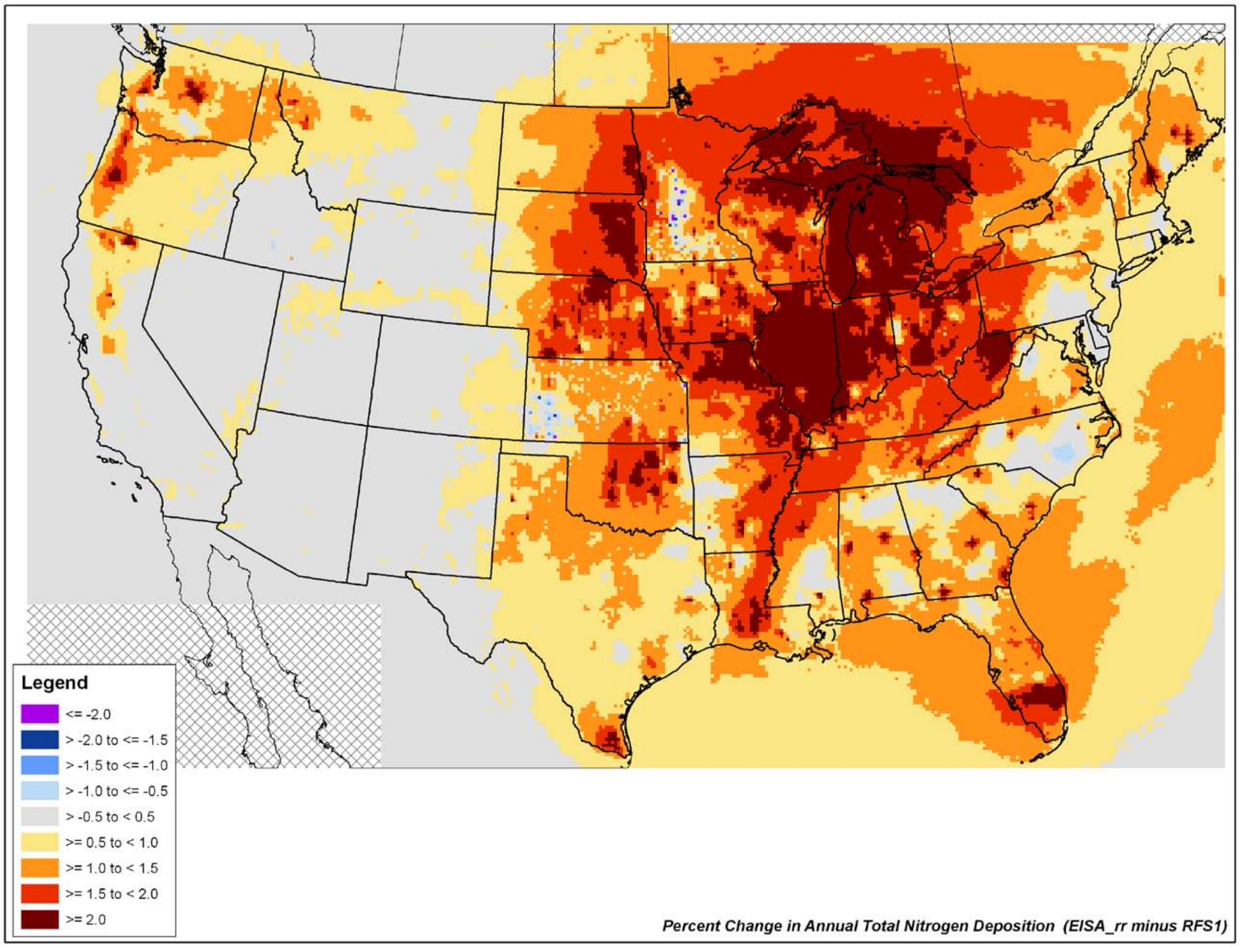


**Figure 3.4-34. Percent Change in Annual Total Sulfur over the U.S. Modeling Domain Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022**

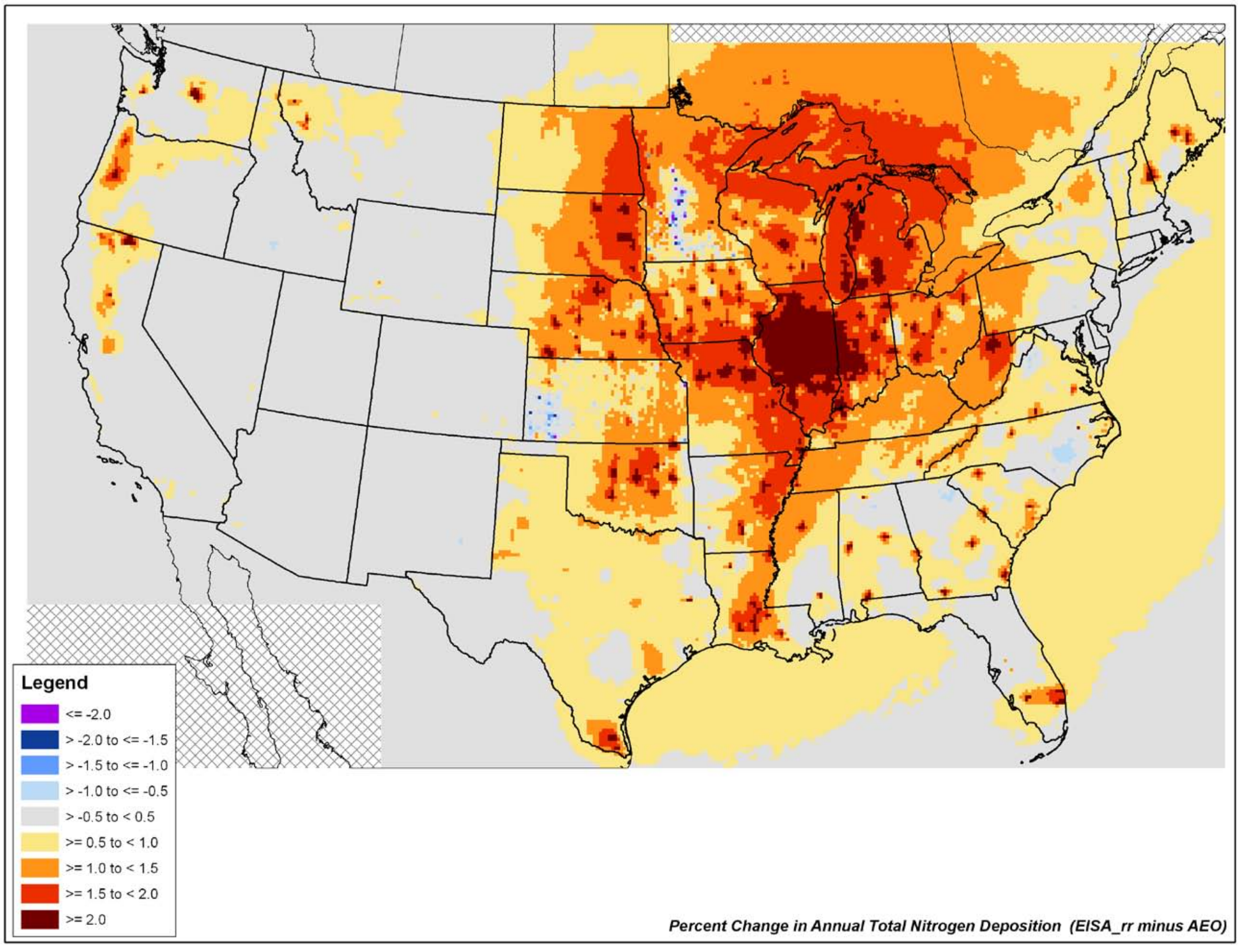


**Figure 3.4-35. Percent Change in Annual Total Nitrogen over the U.S. Modeling Domain Between the AEO Reference Case and the RFS2 Control Case in 2022**

For sulfur deposition, Figure 3.4-36 shows that when compared to the RFS1 mandate reference case, the RFS2 renewable fuel volumes will result in annual percent increases in the Midwest ranging from 1% to more than 4%. Some rural areas in the west, likely associated with new ethanol plants, will also have increases in sulfur deposition ranging from 1% to more than 4% as a result of the RFS2 renewable fuel volumes. Figure 3.4-37 shows that when compared to the AEO 2007 reference case, the changes are more limited. The Midwest will still have sulfur deposition increases ranging from 1% to more than 4%, but the size of the area with these changes will be smaller. The Pacific Northwest has minimal areas with increases in sulfur deposition when compared to the AEO 2007 reference case. When compared to both the RFS1 mandate and 2007 reference cases, areas along the Gulf Coast in Louisiana and Texas will experience decreases in sulfur deposition of 2% to more than 4%. The remainder of the country will see only minimal changes in sulfur deposition, ranging from decreases of less than 1% to increases of less than 1%.

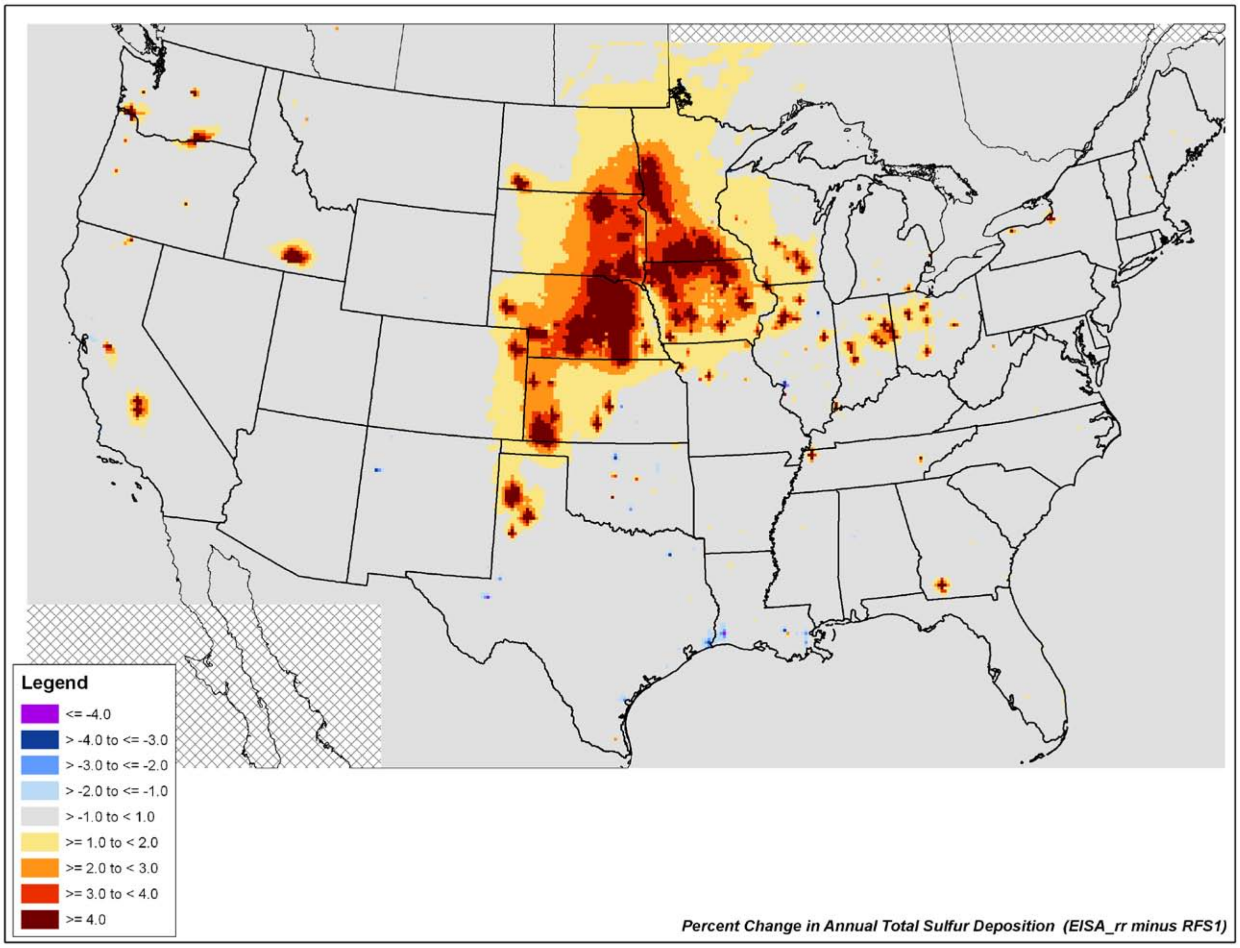


**Figure 3.4-36. Percent Change in Annual Total Sulfur over the U.S. Modeling Domain Between the RFS1 Mandate Reference Case and the RFS2 Case in 2022**

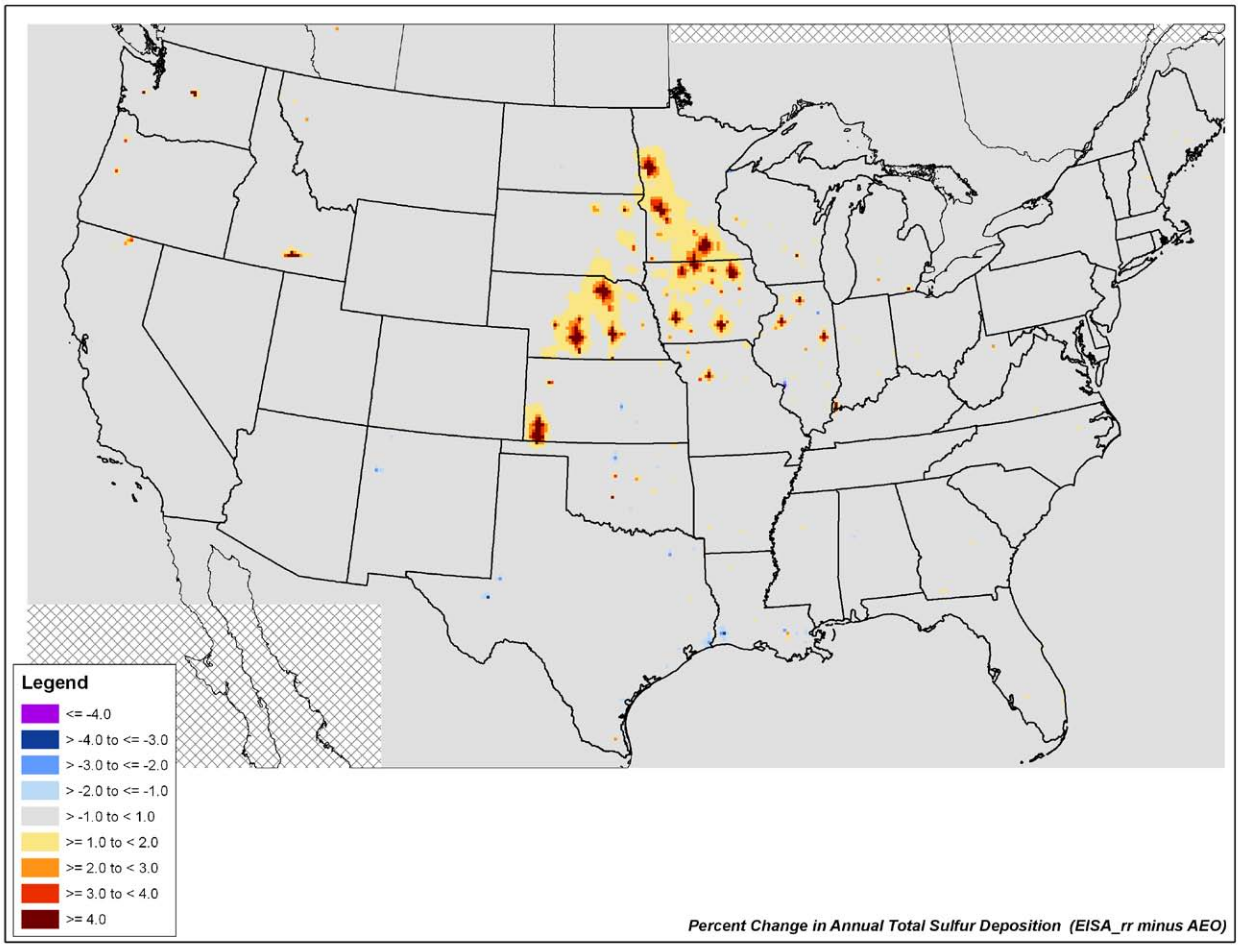


**Figure 3.4-37. Percent Change in Annual Total Sulfur over the U.S. Modeling Domain Between the AEO Reference Case and the RFS2 Case in 2022**

### 3.4.3 Ambient Monitoring and Modeling Studies of Ethanol's Impacts on Air Quality

A number of ambient monitoring and modeling studies in the U.S. and abroad have quantified the relative concentrations of ethanol emissions and the potential air quality impacts of using ethanol in fuels. This section summarizes the main results of these studies and is not meant to be a comprehensive examination of this work.

#### 3.4.3.1 U.S. Studies

In 1986, Colorado adopted the first state-wide regulation in the country that required the use of oxygenated fuels in winter time months to reduce carbon monoxide (CO) emissions. From the time the regulation was first adopted, the fuels used quickly shifted from methyl tertiary butyl ether (MTBE) and gasoline to largely ethanol-blended fuels. By the winter of 1996-1997, nearly all of the fuel was blended with ethanol at 10% by volume. The effect of using oxygenated fuels on formaldehyde and acetaldehyde concentrations was monitored by ambient air quality measurements from the winter of 1987-1988 (95% of fuel blended with

MTBE) through the winter of 1996-1997 (nearly all fuel blended with ethanol). Analysis of the data by Anderson et al. showed no clear effect on ambient concentrations of formaldehyde and acetaldehyde through ten winters of oxygenated fuels use.[853,854] Furthermore, Anderson et al. reported that the concentrations of formaldehyde and acetaldehyde during the winter of 1995-1996 when nearly all of the fuel was blended with ethanol were not significantly different from those measured during the winter of 1988-1989 when 95% of the fuel was blended with MTBE. It was hypothesized that the photochemical production and destruction of these compounds suppressed the emissions effect. They concluded that mobile source emissions are the major photochemical sources and sinks for both compounds.[855] Anderson et al. supported this conclusion by citing the work of Altshuller, which showed that most acetaldehyde production comes from alkenes.[856, 857, 858]

Albuquerque, NM is another location that mandated the use of oxygenates in the wintertime to reduce CO emissions. A field study was conducted in Albuquerque to determine the atmospheric impacts of the use of ethanol fuels.[859,860] Atmospheric concentrations of ozone, $NO_x$, CO, PAN, aldehydes, and organic acids were measured in the summer of 1993, before the use of ethanol fuels, and in the winters of 1994 and 1995, during the use of 10% ethanol fuel (>99%). There were no data for pre-ethanol winter conditions. Results showed increased levels of PAN and an increase in acetaldehyde in one winter, but a decrease in the other. Seasonal differences were not considered. The authors noted that the daytime temperatures were fairly comparable for the summer and winter study periods so it appeared that the significantly higher winter values, despite the much lower photochemical reactivity in winter, were primarily due to local production of PAN. For acetaldehyde, winter values were about twice as high as the summer values. These acetaldehyde levels anti-correlated with PAN levels, indicating a primary source of aldehydes in the winter.

Grosjean et al (2002) conducted monitoring studies in various California cities and measured daily maximum PAN concentrations ranging from 0.2 to 6.9 ppb.[861] Peroxypropionyl nitrate (PPN, a compound similar to PAN) concentrations were measured at lower levels and ranged from 0.33-1.04 ppb. This study concluded that aromatics and alkene compounds are responsible for significant PAN formation with ethanol and acetaldehyde having a minor role. A modeling analysis using the Urban Airshed Model (UAM), was performed by the California Air Resources Board in 1999.[862] Acetaldehyde and ethanol concentrations in 2003, relative to an MTBE baseline, were estimated to increase for 3.5% by weight ethanol-blended gasoline by 4% and 72%, respectively. There was no significant impact on PAN formation. Benzene increased 1%, formaldehyde increased 2 to 4%, butadiene decreased about 2%, and $NO_2$ (0 to 1%) and peroxypropionyl nitrate (PPN) were essentially unchanged. It should be noted that the chemical mechanism used in this modeling is a previous version of the mechanism used in the modeling for this rule, so comparability of results are limited.

Another air quality modeling study by Jacobson et al. investigated the projected impacts of widespread usage of E85 in Los Angeles and the US in 2020.[863] Overall results showed increases in acetaldehyde and formaldehyde and decreases in 1,3-butadiene and benzene in Los Angeles and the U.S. Sources of acetaldehyde included direct emissions and to a larger degree photooxidation of unburned ethanol. Results of this modeling study also showed increases in unburned ethanol, PAN, and ozone for a future E85 scenario. The results of Jacobson et al.

study differ from the results of our air quality modeling analysis for a number of reasons. First, the scenario modeled in Jacobson et al. study would result in much larger volumes of ethanol in the fuel supply than mandated under EISA (and much greater than could feasibly be produced). This study also did not include upstream impacts from fuel distribution. As discussed elsewhere (Section 3.4.1.3), VOC speciation data used for gasoline storage and distribution and gas cans result in reduction of some acetaldehyde precursor emissions. Finally, the modeled scenario includes large reductions in $NO_x$ emissions. In contrast, we modeled the "more sensitive" emission inventory case where $NO_x$ emissions increased with greater use of E10 fuel. Increases in $NO_X$, may result in more acetyl peroxy radical forming PAN rather than acetaldehyde.
The U.S. monitoring studies discussed here are largely winter studies and the lack of summer studies makes it difficult to quantify the magnitude of air quality impacts of ethanol fuel usage over the entire year.

### 3.4.3.2 Brazilian Studies

The following studies investigate changes in ambient concentrations of several air pollutants that result from the use of ethanol fuels in Brazil. These studies are not directly relevant to the U.S. due to differences such as vehicles (including less stringent emission standards), fuels, and climate. However, these studies do provide useful information on potential directional changes in pollutant levels with widespread ethanol use.

Brazil is the first country in the world where a nationwide, large-scale alcohol fuel program has been implemented. In 1997, approximately 4 million automobiles ran on neat ethanol and approximately nine million automobiles ran on a 22% ethanol-blended gasoline mixture.[864] It should be noted that Brazilian ethanol blended gasoline does not have RVP controls like U. S. blends.

In Salvador, Bahia, Brazil, ambient levels of formaldehyde and acetaldehyde and their relationship with vehicular fleet composition were evaluated.[865] The measured concentrations for formaldehyde and acetaldehyde ranged from 0.20 to 88 parts per billion by volume (ppbv) and from 0.40 to 93 ppbv, respectively. The ratio of formaldehyde to acetaldehyde revealed the relationship of vehicular fleet composition to ambient levels. In locations where ethanol-fueled vehicular emissions dominated, the ratio decreased, versus locations where diesel-fueled vehicles dominated. Sampling in rural areas showed no relationship between formaldehyde and acetaldehyde.

Acetaldehyde and formaldehyde concentrations were measured in the winter of 1999 in Sao Paulo, Brazil.[866] Ambient levels of these carbonyls were similar. Higher average mixing ratios of acetaldehyde and formaldehyde were found in the morning (18.9 and 17.2 ppbv) than midday (9.5 and 11.8 ppbv) and evening (7.2 and 10.2 ppbv). In the morning, direct emission from vehicles seemed to be the main primary source, whereas at midday and evening these compounds appeared to result mainly from photochemistry.

A survey of volatile organic compounds in areas impacted by heavy traffic, including a tunnel, was obtained for Sao Paulo.[867] Researchers found the ambient air was dominated by ethanol (414 ppbv) with elevated methanol and 1- and 2-propanol. These levels were well above those measurements available for U.S. cities, particularly Los Angeles, CA. The overall data trend also showed levels of $C_4$-$C_9$ *n*-aldehydes to be approximately 10 times higher than in Los Angeles. They conclude that the use of alcohol-based fuels is the primary source for these differences since alcohol comprises about 40% of the mobile fuel by volume compared to 3% in Los Angeles. Also, the single-ring aromatic hydrocarbons (2.6 ppbv benzene, 9.0 ppbv toluene, 4.6 ppbv *m,p*-xylene) and the $C_4$-$C_{11}$ *n*-alkanes were similar or slightly elevated in concentration compared to Los Angeles.

A study in Rio de Janeiro, Brazil some years ago measured and modeled ambient PAN concentrations.[868] The measurements were as high as 5 ppb over a 200 day period, but typically below 1 ppb, at one site; at another site, as high as 3 ppb, but again generally below 1 ppb. Modeling estimates were as high as 3 ppb for PAN and 1 ppb for PPN. This study concluded that with increased use of ethanol in fuels there would be increases in ambient PAN.
More recent monitoring studies in Brazil measured daily maximum PAN concentrations ranging from 0.19 to 6.67 ppb.[869] Also, PPN was measured at lower levels of 0.06 to 0.72 ppb. During the 41 days of these measurements, PAN levels accounted for a large fraction of the ambient $NO_x$. This study concluded that aromatics and alkene compounds are responsible for significant PAN formation with ethanol and acetaldehyde having a minor role.

Speciated ambient carbonyls have also been measured in Rio de Janeiro.[870] The most abundant carbonyls were formaldehyde (9.3 ppb) and acetaldehyde (9.0 ppb). The researchers also examined the ambient acetaldehyde to formaldehyde concentration ratio in Brazilian cities since mid-1980 in the context of changes in Brazil's reliance on ethanol as a vehicle fuel. They showed that this ratio has begun to decrease in recent years due to fleet turnover and decrease in ethanol-fueled vehicles. Ethanol-fueled vehicles are being replaced by lower-emitting newer models that run on a gasoline-ethanol blend.

Using an empirical kinetic modeling approach (EKMA), researchers simulated ozone, formaldehyde, and acetaldehyde concentrations for the urban downtown area of Rio de Janeiro.[871] The simulated ozone peak was in good agreement with monitoring results. Modeling results also showed that acetaldehyde and formaldehyde concentrations were highest in early morning, reaching a maximum which coincided with peak vehicular traffic. Additionally, they confirmed monitoring evidence that the high acetaldehyde to formaldehyde ratios were due to the use of alcohol-based fuels.

These studies modeled and measured ambient concentrations of several compounds that result from the use of ethanol fuels. However, the direct impacts of ethanol fuel usage on air quality in Brazil could not be evaluated since there were no ambient data available prior to the use of ethanol fuel. Notably, these studies did not include ambient measurements of acetaldehyde prior to the use of ethanol fuel, and measured concentrations were much higher than those found in the United States. However, gasolines in Brazil lacked RVP control, resulting in higher evaporative ethanol emissions than would be likely in the U. S., fuel ethanol levels were much higher (neat ethanol or 22% ethanol by volume), and there were significant differences in the vehicle fleet and meteorology. Also, vehicles in Brazil do not meet the same stringent emissions exhaust and evaporative emission standards as vehicles do in the U.S. These factors would all contribute to larger acetaldehyde impacts with ethanol use than expected in the U.S. under the control case evaluated for this rule.

#### 3.4.3.3 Other Studies

A review was conducted on studies that looked at the environmental impacts of E10 and E85 compared to E0.[872] The review article focused on five environmental outcomes including the impact of increased usage of E10 and/or E85 on air pollutant emissions. The review article focuses on studies that are relevant to Australia but includes work done in the US and elsewhere and the results are characterized as being “broad and applicable to most industrialized countries in moderate temperate climates.” The author concludes that using E10 fuel instead of E0 fuel provides minimal improvements in air pollutant emissions, specifically E10 causes lower tailpipe CO and particulate emissions but higher acetaldehyde, ethanol and NOx emissions and that there is some evidence of a connection between E10 and higher ground-level ozone concentrations. Since this is a review article it is difficult to compare the modeling for this final rule to the article, however some of the conclusions from the article are useful when interpreting the air quality modeling results.

Some smog chamber studies were recently conducted at EPA[873] with two fuels. These studies were done on headspace vapors which are the hydrocarbon compounds formed by vaporization of hydrocarbon components from gasoline stored in closed (or semi-closed) containers such as fuel storage tanks or tanker trucks. These emissions are different from exhaust emissions which include products of combustion. They are also somewhat different from vehicle evaporative emissions in that the charcoal canister tends to adsorb the higher molecular weight hydrocarbons resulting in emissions of the more volatile fuel components.

The first fuel used in these smog chamber studies was a base gasoline and the second was this gasoline with 10% ethanol added to it (a “splash blend” without any control of fuel volatility). The smog chamber runs were conducted for 24 hours with a target HC/NOx ratio of 10-to-1. The chamber runs with the base gasoline had a higher initial concentration of isopentane compared to the runs with the base gasoline with 10% ethanol. The runs showed that the photoxidation processes of ethanol results in higher levels of acetaldehyde. This photoxidation should also increase acetone levels with the base gasoline which is also observed. The significance of these results is that ethanol does result in increased acetaldehyde formation in smog chamber work. It is important to be able to translate these smog chamber results to actual atmospheric conditions by using such studies to better improve the chemical mechanisms in air quality models to simulate what happens in the atmosphere with other emission components (exhaust, evaporative, other emissions) in actual atmospheric condtions (with meteorology, mixing conditions, temperature, concentrations, and mixing being what they are in the atmosphere).

## 3.5 Health Effects

In this section we discuss the health and environmental effects associated with particulate matter, ozone, $NO_X$, $SO_X$, carbon monoxide and air toxics. The renewable fuel requirements established by the Energy Independence and Security Act (EISA) of 2007 will impact emissions of criteria and air toxic pollutants.

### 3.5.1 Particulate Matter

#### 3.5.1.1 Background

Particulate matter (PM) is a generic term for a broad class of chemically and physically diverse substances. It can be principally characterized as discrete particles that exist in the condensed (liquid or solid) phase spanning several orders of magnitude in size. Since 1987, EPA has delineated that subset of inhalable particles small enough to penetrate to the thoracic region (including the tracheobronchial and alveolar regions) of the respiratory tract (referred to as thoracic particles). Current national ambient air quality standards (NAAQS) use $PM_{2.5}$ as the indicator for fine particles (with $PM_{2.5}$ referring to particles with a nominal mean aerodynamic diameter less than or equal to 2.5 µm), and use $PM_{10}$ as the indicator for purposes of regulating the coarse fraction of $PM_{10}$ (referred to as thoracic coarse particles or coarse-fraction particles; generally including particles with a nominal mean aerodynamic diameter greater than 2.5 µm and less than or equal to 10 µm, or $PM_{10\text{-}2.5}$). Ultrafine particles are a subset of fine particles, generally less than 100 nanometers (0.1 µm) in aerodynamic diameter.

Particles span many sizes and shapes and consist of hundreds of different chemicals. Particles originate from sources and are also formed through atmospheric chemical reactions; the former are often referred to as “primary” particles, and the latter as “secondary” particles. In addition, there are also physical, non-chemical reaction mechanisms that contribute to secondary particles. Particle pollution also varies by time of year and location and is affected by several weather-related factors, such as temperature, clouds, humidity, and wind. A further layer of complexity comes from a particle’s ability to shift between solid/liquid and gaseous phases, which is influenced by concentration, meteorology, and temperature.

Fine particles are produced primarily by combustion processes and by transformations of gaseous emissions (e.g., $SO_X$, $NO_X$ and VOCs) in the atmosphere. The chemical and physical properties of $PM_{2.5}$ may vary greatly with time, region, meteorology and source category. Thus, $PM_{2.5}$ may include a complex mixture of different pollutants including sulfates, nitrates, organic compounds, elemental carbon and metal compounds. These particles can remain in the atmosphere for days to weeks and travel through the atmosphere hundreds to thousands of kilometers.[874]

#### 3.5.1.2 Health Effects of PM

This section provides a summary of the health effects associated with exposure to ambient concentrations of PM.[DDDDDDDDD] The information in this section is based on the data and conclusions in the PM Air Quality Criteria Document (PM AQCD) and PM Staff Paper

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[DDDDDDDDD] Personal exposure includes contributions from many different types of particles, from many sources, and in many different environments. Total personal exposure to PM includes both ambient and nonambient components; and both components may contribute to adverse health effects.

prepared by the U.S. Environmental Protection Agency (EPA).[EEEEEEEEE,875,876] We also present additional recent studies published after the cut-off date for the PM AQCD.[877,FFFFFFFFF] Taken together this information supports the conclusion that exposure to ambient concentrations of PM are associated with adverse health effects.

#### 3.5.1.2.1 Short-term Exposure Mortality and Morbidity Studies

As discussed in the PM AQCD, short-term exposure to $PM_{2.5}$ is associated with premature mortality from cardiopulmonary diseases,[878] hospitalization and emergency department visits for cardiopulmonary diseases,[879] increased respiratory symptoms,[880] decreased lung function[881] and physiological changes or biomarkers for cardiac changes.[882],[883] In addition, the PM AQCD described a limited body of new evidence from epidemiologic studies for potential relationships between short term exposure to PM and health endpoints such as low birth weight, preterm birth, and neonatal and infant mortality.[884]

Among the studies of effects associated with short-term exposure to $PM_{2.5}$, several specifically address the contribution of mobile sources to short-term $PM_{2.5}$-related effects on premature mortality. The results from these studies generally indicated that several combustion-related fine particle source-types are likely associated with mortality, including motor vehicle emissions as well as other sources.[885] The analyses incorporate source apportionment tools into short-term exposure studies and are briefly mentioned here. Analyses incorporating source apportionment by factor analysis with daily time-series studies of daily death rates indicated a relationship between mobile source $PM_{2.5}$ and mortality.[886,887,888,889] Another recent study in 14 U.S. cities examined the effect of $PM_{10}$ exposures on daily hospital admissions for cardiovascular disease. This study found that the effect of $PM_{10}$ was significantly greater in areas with a larger proportion of $PM_{10}$ coming from motor vehicles, indicating that $PM_{10}$ from these sources may have a greater effect on the toxicity of ambient $PM_{10}$ when compared with other sources.[890] These studies provide evidence that PM-related emissions, specifically from mobile sources, are associated with adverse health effects.

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[EEEEEEEEE] The PM NAAQS is currently under review and the EPA is considering all available science on PM health effects, including information which has been published since 2004, in the development of the upcoming PM Integrated Science Assessment Document (ISA). A second draft of the PM ISA was completed in July 2009 and was submitted for review by the Clean Air Scientific Advisory Committee (CASAC) of EPA's Science Advisory Board. Comments from the general public have also been requested. For more information, see http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=210586.

[FFFFFFFFF] These additional studies are included in the 2006 Provisional Assessment of Recent Studies on Health Effects of Particulate Matter Exposure. The provisional assessment did not and could not (given a very short timeframe) undergo the extensive critical review by CASAC and the public, as did the PM AQCD. The provisional assessment found that the "new" studies expand the scientific information and provide important insights on the relationship between PM exposure and health effects of PM. The provisional assessment also found that "new" studies generally strengthen the evidence that acute and chronic exposure to fine particles and acute exposure to thoracic coarse particles are associated with health effects. Further, the provisional science assessment found that the results reported in the studies did not dramatically diverge from previous findings, and taken in context with the findings of the AQCD, the new information and findings did not materially change any of the broad scientific conclusions regarding the health effects of PM exposure made in the AQCD. However, it is important to note that this assessment was limited to screening, surveying, and preparing a provisional assessment of these studies. For reasons outlined in Section I.C of the preamble for the final PM NAAQS rulemaking in 2006 (see 71 FR 61148-49, October 17, 2006), EPA based its NAAQS decision on the science presented in the 2004 AQCD.

### 3.5.1.2.2 Long-term Exposure Mortality and Morbidity Studies

Long-term exposure to ambient $PM_{2.5}$ is associated with premature mortality from cardiopulmonary diseases and lung cancer,[891] and effects on the respiratory system such as decreased lung function or the development of chronic respiratory disease.[892] Of specific importance, the PM AQCD also noted that the PM components of gasoline and diesel engine exhaust represent one class of hypothesized likely important contributors to the observed ambient PM-related increases in lung cancer incidence and mortality.[893]

The PM AQCD and PM Staff Paper emphasized the results of two long-term epidemiologic studies, the Six Cities and American Cancer Society (ACS) prospective cohort studies, based on several factors – the large air quality data set for PM in the Six Cities Study, the fact that the study populations were similar to the general population, and the fact that these studies have undergone extensive reanalysis.[894,895,896,897898,899] These studies indicate that there are positive associations for all-cause, cardiopulmonary, and lung cancer mortality with long-term exposure to $PM_{2.5}$. One analysis of a subset of the ACS cohort data, which was published after the PM AQCD was finalized but in time for the 2006 Provisional Assessment, found a larger association than had previously been reported between long-term $PM_{2.5}$ exposure and mortality from all causes and cardiopulmonary diseases in the Los Angeles area using a new exposure estimation method that accounted for variations in concentration within the city.[900]

As discussed in the PM AQCD, the morbidity studies that combine the features of cross-sectional and cohort studies provide the best evidence for chronic exposure effects. Long-term studies evaluating the effect of ambient PM on children's development have shown some evidence indicating effects of $PM_{2.5}$ and/or $PM_{10}$ on reduced lung function growth.[901] In another recent publication included in the 2006 Provisional Assessment, investigators in southern California reported the results of a cross-sectional study of outdoor $PM_{2.5}$ and a measure of atherosclerosis development in the Los Angeles basin.[902] The study found positive associations between ambient residential $PM_{2.5}$ and carotid intima-media thickness (CIMT), an indicator of subclinical atherosclerosis that is an underlying factor in cardiovascular disease.

### 3.5.1.2.3 Roadway-Related PM Exposure and Health Studies

A recent body of studies examines traffic-related PM exposures and adverse health effects. However, note that the near-road environment is influenced by both gasoline spark-ignition (SI) and diesel vehicles, as well as re-entrained road dust and brake and tire wear. One study was done in North Carolina looking at concentrations of $PM_{2.5}$ inside highway patrol cars and corresponding physiological changes in state troopers driving the cars. The authors report significant elevations in markers of cardiovascular effects (i.e., inflammation, coagulation, and cardiac rhythm) associated with concentrations of $PM_{2.5}$ inside highway patrol cars on North Carolina state highways.[903] Other studies have found associations between traffic-generated particle concentrations at residences and adverse effects, including all-cause mortality, infant respiratory symptoms, and reduced cognitive functional development.[904,905,906,907] There are other pollutants present in the near-roadway environment, including air toxics which are discussed in Section 3.4.5, and it is important to note that current studies do not identify a single pollutant that is most associated with adverse health effects. Additional information on near-roadway health effects can be found in the recent Mobile Source Air Toxics rule (72 FR 8428, February 26, 2007).

### 3.5.2 Ozone

#### 3.5.2.1 Background

Ground-level ozone pollution is formed by the reaction of VOCs and $NO_X$ in the atmosphere in the presence of heat and sunlight. These pollutants, often referred to as ozone precursors, are emitted by many types of pollution sources such as highway vehicles and nonroad engines, power plants, chemical plants, refineries, makers of consumer and commercial products, industrial facilities, and smaller area sources.

The science of ozone formation, transport, and accumulation is complex. Ground-level ozone is produced and destroyed in a cyclical set of chemical reactions, many of which are sensitive to temperature and sunlight. When ambient temperatures and sunlight levels remain high for several days and the air is relatively stagnant, ozone and its precursors can build up and result in more ozone than typically would occur on a single high-temperature day. Ozone can be transported hundreds of miles downwind of precursor emissions, resulting in elevated ozone levels even in areas with low VOC or $NO_X$ emissions.

As mentioned above in Section 3.4.2.1.2, the highest levels of ozone are produced when both VOC and $NO_X$ emissions are present in significant quantities on clear summer days. Relatively small amounts of $NO_X$ enable ozone to form rapidly when VOC levels are relatively high, but ozone production is quickly limited by removal of the $NO_X$. Under these conditions $NO_X$ reductions are highly effective in reducing ozone while VOC reductions have little effect. Such conditions are called "$NO_X$-limited." Because the contribution of VOC emissions from biogenic (natural) sources to local ambient ozone concentrations can be significant, even some areas where man-made VOC emissions are relatively low can be $NO_X$-limited.

Ozone concentrations in an area also can be lowered by the reaction of nitric oxide (NO) with ozone, forming nitrogen dioxide ($NO_2$); as the air moves downwind and the cycle continues, the $NO_2$ forms additional ozone. The importance of this reaction depends, in part, on the relative concentrations of $NO_X$, VOC, and ozone, all of which change with time and location. When $NO_X$ levels are relatively high and VOC levels relatively low, $NO_X$ forms inorganic nitrates (i.e., particles) but relatively little ozone. Such conditions are called "VOC-limited". Under these conditions, VOC reductions are effective in reducing ozone, but $NO_X$ reductions can actually increase local ozone under certain circumstances. Even in VOC-limited urban areas, $NO_X$ reductions are not expected to increase ozone levels if the $NO_X$ reductions are sufficiently large. Rural areas are usually $NO_X$-limited, due to the relatively large amounts of biogenic VOC emissions in such areas. Urban areas can be either VOC- or $NO_X$-limited, or a mixture of both, in which ozone levels exhibit moderate sensitivity to changes in either pollutant.

#### 3.5.2.2 Health Effects of Ozone

Exposure to ambient ozone contributes to a wide range of adverse health effects.[GGGGGGGGG] These health effects are well documented and are critically assessed in the EPA ozone air quality criteria document (ozone AQCD) and EPA staff paper.[908,909] We are relying on the data and conclusions in the ozone AQCD and staff paper, regarding the health effects associated with ozone exposure.

Ozone-related health effects include lung function decrements, respiratory symptoms, aggravation of asthma, increased hospital and emergency room visits, increased asthma medication usage, and a variety of other respiratory effects. Cellular-level effects, such as inflammation of lungs, have been documented as well. In addition, there is suggestive evidence of a contribution of ozone to cardiovascular-related morbidity and highly suggestive evidence that short-term ozone exposure directly or indirectly contributes to non-accidental and cardiopulmonary-related mortality, but additional research is needed to clarify the underlying mechanisms causing these effects. In a recent report on the estimation of ozone-related premature mortality published by the National Research Council (NRC), a panel of experts and reviewers concluded that short-term exposure to ambient ozone is likely to contribute to premature deaths and that ozone-related mortality should be included in estimates of the health benefits of reducing ozone exposure.[910] People who appear to be more susceptible to effects associated with exposure to ozone include children, asthmatics and the elderly. Those with greater exposures to ozone, for instance due to time spent outdoors (e.g., children and outdoor workers), are also of concern.

Based on a large number of scientific studies, EPA has identified several key health effects associated with exposure to levels of ozone found today in many areas of the country. Short-term (1 to 3 hours) and prolonged exposures (6 to 8 hours) to ambient ozone concentrations have been linked to lung function decrements, respiratory symptoms, increased hospital admissions and emergency room visits for respiratory problems.[911, 912, 913, 914, 915, 916] Repeated exposure to ozone can increase susceptibility to respiratory infection and lung inflammation and can aggravate preexisting respiratory diseases, such as asthma.[917, 918, 919, 920, 921] Repeated exposure to sufficient concentrations of ozone can also cause inflammation of the lung, impairment of lung defense mechanisms, and possibly irreversible changes in lung structure, which over time could affect premature aging of the lungs and/or the development of chronic respiratory illnesses, such as emphysema and chronic bronchitis.[922, 923, 924, 925]

Children and adults who are outdoors and active during the summer months, such as construction workers, are among those most at risk of elevated ozone exposures.[926] Children and outdoor workers tend to have higher ozone exposure because they typically are active outside, working, playing and exercising, during times of day and seasons (e.g., the summer) when ozone levels are highest.[927] For example, summer camp studies in the Eastern United States and Southeastern Canada have reported statistically significant reductions in lung function in children who are active outdoors.[928, 929, 930, 931, 932, 933, 934, 935] Further, children are more at risk of experiencing health effects from ozone exposure than adults because their respiratory systems are still developing. These individuals (as well as people with respiratory illnesses, such as

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[GGGGGGGGG] Human exposure to ozone varies over time due to changes in ambient ozone concentration and because people move between locations which have notable different ozone concentrations. Also, the amount of ozone delivered to the lung is not only influenced by the ambient concentrations but also by the individuals breathing route and rate.

asthma, especially asthmatic children) can experience reduced lung function and increased respiratory symptoms, such as chest pain and cough, when exposed to relatively low ozone levels during prolonged periods of moderate exertion.[936, 937, 938, 939]

### 3.5.3 Nitrogen Oxides and Sulfur Oxides

#### 3.5.3.1 Background

Sulfur dioxide ($SO_2$), a member of the sulfur oxide ($SO_X$) family of gases, is formed from burning fuels containing sulfur (e.g., coal or oil), extracting gasoline from oil, or extracting metals from ore. Nitrogen dioxide ($NO_2$) is a member of the nitrogen oxide ($NO_X$) family of gases. Most $NO_2$ is formed in the air through the oxidation of nitric oxide (NO) emitted when fuel is burned at a high temperature. $SO_2$ and $NO_2$ can dissolve in water vapor and further oxidize to form sulfuric and nitric acid which react with ammonia to form sulfates and nitrates, both of which are important components of ambient PM. The health effects of ambient PM are discussed in Section 3.5.1.2. $NO_X$ along with non-methane hydrocarbons (NMHC) are the two major precursors of ozone. The health effects of ozone are covered in Section 3.5.2.2.

#### 3.5.3.2 Health Effects of Sulfur Oxides

Information on the health effects of $SO_2$ can be found in the U.S. Environmental Protection Agency Integrated Science Assessment for Sulfur Oxides.[HHHHHHHHH] $SO_2$ has long been known to cause adverse respiratory health effects, particularly among individuals with asthma. Other potentially sensitive groups include children and the elderly. During periods of elevated ventilation, asthmatics may experience symptomatic bronchoconstriction within minutes of exposure. Following an extensive evaluation of health evidence from epidemiologic and laboratory studies, the EPA has concluded that there is a causal relationship between respiratory health effects and short-term exposure to $SO_2$. Separately, based on an evaluation of the epidemiologic evidence of associations between short-term exposure to $SO_2$ and mortality, the EPA has concluded that the overall evidence is suggestive of a causal relationship between short-term exposure to $SO_2$ and mortality.

#### 3.5.3.3 Health Effects of Nitrogen Oxides

Information on the health effects of $NO_2$ can be found in the U.S. Environmental Protection Agency Integrated Science Assessment (ISA) for Nitrogen Oxides.[IIIIIIIII] The U.S. EPA has concluded that the findings of epidemiologic, controlled human exposure, and animal toxicological studies provide evidence that is sufficient to infer a likely causal relationship between respiratory effects and short-term $NO_2$ exposure. The ISA concludes that the strongest evidence for such a relationship comes from epidemiologic studies of respiratory effects

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[HHHHHHHHH] U.S. EPA. (2008). *Integrated Science Assessment (ISA) for Sulfur Oxides – Health Criteria (Final Report).* EPA/600/R-08/047F. Washington, DC: U.S. Environmental Protection Agency. Retrieved on March 18, 2009 from http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=198843

[IIIIIIIII] U.S. EPA (2008). *Integrated Science Assessment for Oxides of Nitrogen – Health Criteria (Final Report).* EPA/600/R-08/071. Washington, DC,: U.S.EPA. Retrieved on March 19, 2009 from http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=194645.

including symptoms, emergency department visits, and hospital admissions. The ISA also draws two broad conclusions regarding airway responsiveness following $NO_2$ exposure. First, the ISA concludes that $NO_2$ exposure may enhance the sensitivity to allergen-induced decrements in lung function and increase the allergen-induced airway inflammatory response following 30-minute exposures of asthmatics to $NO_2$ concentrations as low as 0.26 ppm. In addition, small but significant increases in non-specific airway hyperresponsiveness were reported following 1-hour exposures of asthmatics to 0.1 ppm $NO_2$. Second, exposure to $NO_2$ has been found to enhance the inherent responsiveness of the airway to subsequent nonspecific challenges in controlled human exposure studies of asthmatic subjects. Enhanced airway responsiveness could have important clinical implications for asthmatics since transient increases in airway responsiveness following $NO_2$ exposure have the potential to increase symptoms and worsen asthma control. Together, the epidemiologic and experimental data sets form a plausible, consistent, and coherent description of a relationship between $NO_2$ exposures and an array of adverse health effects that range from the onset of respiratory symptoms to hospital admission.

Although the weight of evidence supporting a causal relationship is somewhat less certain than that associated with respiratory morbidity, $NO_2$ has also been linked to other health endpoints. These include all-cause (nonaccidental) mortality, hospital admissions or emergency department visits for cardiovascular disease, and decrements in lung function growth associated with chronic exposure.

### 3.5.4 Carbon Monoxide

This section summarizes the data and conclusions in the EPA Air Quality Criteria Document for CO (CO Criteria Document), which was published in 2000, regarding the health effects associated with CO exposure.[JJJJJJJJJ,940] Carbon monoxide enters the bloodstream through the lungs and forms carboxyhemoglobin (COHb), a compound that inhibits the blood's capacity to carry oxygen to organs and tissues.[941,942] Carbon monoxide has long been known to have substantial adverse effects on human health, including toxic effects on blood and tissues, and effects on organ functions. Although there are effective compensatory increases in blood flow to the brain, at some concentrations of COHb somewhere above 20 percent, these compensations fail to maintain sufficient oxygen delivery, and metabolism declines.[943] The subsequent hypoxia in brain tissue then produces behavioral effects, including decrements in continuous performance and reaction time.[944]

Carbon monoxide has been linked to increased risk for people with heart disease, reduced visual perception, cognitive functions and aerobic capacity, and possible fetal effects.[945] Persons with heart disease are especially sensitive to CO poisoning and may experience chest pain if they breathe the gas while exercising.[946] Infants, elderly persons, and individuals with respiratory diseases are also particularly sensitive. Carbon monoxide can affect healthy individuals,

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[JJJJJJJJJ] The CO NAAQS is currently under review and the EPA is considering all available science on CO health effects, including information which has been published since 2000, in the development of the upcoming CO Integrated Science Assessment Document (ISA). A second draft of the CO ISA was completed in September 2009 and was submitted for review by the Clean Air Scientific Advisory Committee (CASAC) of EPA's Science Advisory Board. For more information, see http://cfpub.epa.gov/ncea/cfm/recordisplay.cfm?deid=213229.

impairing exercise capacity, visual perception, manual dexterity, learning functions, and ability to perform complex tasks.[947]

Several epidemiological studies have shown a link between CO and premature morbidity (including angina, congestive heart failure, and other cardiovascular diseases). Several studies in the United States and Canada have also reported an association between ambient CO exposures and frequency of cardiovascular hospital admissions, especially for congestive heart failure (CHF). An association between ambient CO exposure and mortality has also been reported in epidemiological studies, though not as consistently or specifically as with CHF admissions. EPA reviewed these studies as part of the CO Criteria Document review process and noted the possibility that the average ambient CO levels used as exposure indices in the epidemiology studies may be surrogates for ambient air mixes impacted by combustion sources and/or other constituent toxic components of such mixes. More research will be needed to better clarify CO's role.[948]

### 3.5.5 Health Effects of Air Toxics

Motor vehicle emissions contribute to ambient levels of air toxics known or suspected as human or animal carcinogens, or that have noncancer health effects. The population experiences an elevated risk of cancer and other noncancer health effects from exposure to air toxics.[949] These compounds include, but are not limited to, benzene, 1,3-butadiene, formaldehyde, acetaldehyde, acrolein, polycyclic organic matter (POM), and naphthalene. These compounds, except acetaldehyde, were identified as national or regional risk drivers in the 2002 National-scale Air Toxics Assessment (NATA) and have significant inventory contributions from mobile sources.

According to NATA for 2002, mobile sources were responsible for 47 percent of outdoor toxic emissions, over 50 percent of the cancer risk, and over 80 percent of the noncancer hazard. Benzene is the largest contributor to cancer risk of all 124 pollutants quantitatively assessed in the 2002 NATA and mobile sources were responsible for 59 percent of benzene emissions in 2002. In 2007, EPA finalized vehicle and fuel controls that address this public health risk; it will reduce total emissions of mobile source air toxics by 330,000 tons in 2030, including 61,000 tons of benzene.[950]

Noncancer health effects can result from chronic,[KKKKKKKKK] subchronic,[LLLLLLLLL] or acute[MMMMMMMMM] inhalation exposures to air toxics, and include neurological, cardiovascular, liver, kidney, and respiratory effects as well as effects on the immune and reproductive systems. According to the 2002 NATA, nearly the entire U.S. population was exposed to an average concentration of air toxics that has the potential for adverse noncancer respiratory health effects. This will continue to be the case in 2030, even though toxics concentrations will be lower.

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[KKKKKKKKK] Chronic exposure is defined in the glossary of the Integrated Risk Information (IRIS) database (http://www.epa.gov/iris) as repeated exposure by the oral, dermal, or inhalation route for more than approximately 10% of the life span in humans (more than approximately 90 days to 2 years in typically used laboratory animal species).

[LLLLLLLLL] Defined in the IRIS database as exposure to a substance spanning approximately 10% of the lifetime of an organism.

[MMMMMMMMM] Defined in the IRIS database as exposure by the oral, dermal, or inhalation route for 24 hours or less.

Mobile sources were responsible for over 80 percent of the noncancer (respiratory) risk from outdoor air toxics in 2002. The majority of this risk was from exposure to acrolein. The confidence in the RfC for acrolein is medium and confidence in NATA estimates of population noncancer hazard from ambient exposure to this pollutant is low.[951,952]

The NATA modeling framework has a number of limitations which prevent its use as the sole basis for setting regulatory standards. These limitations and uncertainties are discussed on the 2002 NATA website.[953] Even so, this modeling framework is very useful in identifying air toxic pollutants and sources of greatest concern, setting regulatory priorities, and informing the decision making process.

### 3.5.5.1 Benzene

The EPA's IRIS database lists benzene as a known human carcinogen (causing leukemia) by all routes of exposure, and concludes that exposure is associated with additional health effects, including genetic changes in both humans and animals and increased proliferation of bone marrow cells in mice.[954,955,956] EPA states in its IRIS database that data indicate a causal relationship between benzene exposure and acute lymphocytic leukemia and suggest a relationship between benzene exposure and chronic non-lymphocytic leukemia and chronic lymphocytic leukemia. The International Agency for Research on Carcinogens (IARC) has determined that benzene is a human carcinogen and the U.S. Department of Health and Human Services (DHHS) has characterized benzene as a known human carcinogen.[957,958]

A number of adverse noncancer health effects including blood disorders, such as preleukemia and aplastic anemia, have also been associated with long-term exposure to benzene.[959,960] The most sensitive noncancer effect observed in humans, based on current data, is the depression of the absolute lymphocyte count in blood.[961,962] In addition, recent work, including studies sponsored by the Health Effects Institute (HEI), provides evidence that biochemical responses are occurring at lower levels of benzene exposure than previously known.[963,964,965,966] EPA's IRIS program has not yet evaluated these new data.

### 3.5.5.2 1,3-Butadiene

EPA has characterized 1,3-butadiene as carcinogenic to humans by inhalation.[967,968] The IARC has determined that 1,3-butadiene is a human carcinogen and the U.S. DHHS has characterized 1,3-butadiene as a known human carcinogen.[969,970] There are numerous studies consistently demonstrating that 1,3-butadiene is metabolized into genotoxic metabolites by experimental animals and humans. The specific mechanisms of 1,3-butadiene-induced carcinogenesis are unknown; however, the scientific evidence strongly suggests that the carcinogenic effects are mediated by genotoxic metabolites. Animal data suggest that females may be more sensitive than males for cancer effects associated with 1,3-butadiene exposure; there are insufficient data in humans from which to draw conclusions about sensitive subpopulations. 1,3-butadiene also causes a variety of reproductive and developmental effects in mice; no human data on these effects are available. The most sensitive effect was ovarian atrophy observed in a lifetime bioassay of female mice.[971]

### 3.5.5.3 Ethanol

EPA is conducting an assessment of the cancer and noncancer effects of exposure to ethanol, a compound which is not currently listed in EPA's IRIS. A description of these effects to the extent that information is available will be presented, as required by Section 1505 of EPAct, in a Report to Congress on public health, air quality and water resource impacts of fuel additives. We expect to release that report in 2010.

Extensive data are available regarding adverse health effects associated with the ingestion of ethanol while data on inhalation exposure effects are sparse. As part of the IRIS assessment, pharmacokinetic models are being evaluated as a means of extrapolating across species (animal to human) and across exposure routes (oral to inhalation) to better characterize the health hazards and dose-response relationships for low levels of ethanol exposure in the environment.

The IARC has classified "alcoholic beverages" as carcinogenic to humans based on sufficient evidence that malignant tumors of the mouth, pharynx, larynx, esophagus, and liver are causally related to the consumption of alcoholic beverages.[972] The U.S. DHHS in the 11th Report on Carcinogens also identified "alcoholic beverages" as a known human carcinogen (they have not evaluated the cancer risks specifically from exposure to ethanol), with evidence for cancer of the mouth, pharynx, larynx, esophagus, liver and breast.[973] There are no studies reporting carcinogenic effects from inhalation of ethanol. EPA is currently evaluating the available human and animal cancer data to identify which cancer type(s) are the most relevant to an assessment of risk to humans from a low-level oral and inhalation exposure to ethanol.

Noncancer health effects data are available from animal studies as well as epidemiologic studies. The epidemiologic data are obtained from studies of alcoholic beverage consumption. Effects include neurological impairment, developmental effects, cardiovascular effects, immune system depression, and effects on the liver, pancreas and reproductive system.[974] There is evidence that children prenatally exposed via mothers' ingestion of alcoholic beverages during pregnancy are at increased risk of hyperactivity and attention deficits, impaired motor coordination, a lack of regulation of social behavior or poor psychosocial functioning, and deficits in cognition, mathematical ability, verbal fluency, and spatial memory.[975,976,977,978,979,980,981,982] In some people, genetic factors influencing the metabolism of ethanol can lead to differences in internal levels of ethanol and may render some subpopulations more susceptible to risks from the effects of ethanol.

### 3.5.5.4 Formaldehyde

Since 1987, EPA has classified formaldehyde as a probable human carcinogen based on evidence in humans and in rats, mice, hamsters, and monkeys.[983] EPA is currently reviewing recently published epidemiological data. For instance, research conducted by the National Cancer Institute (NCI) found an increased risk of nasopharyngeal cancer and lymphohematopoietic malignancies such as leukemia among workers exposed to formaldehyde.[984,985] In an analysis of the lymphohematopoietic cancer mortality from an extended follow-up of these workers, NCI confirmed an association between lymphohematopoietic cancer risk and peak exposures.[986] A recent National Institute of

Occupational Safety and Health (NIOSH) study of garment workers also found increased risk of death due to leukemia among workers exposed to formaldehyde.[987] Extended follow-up of a cohort of British chemical workers did not find evidence of an increase in nasopharyngeal or lymphohematopoietic cancers, but a continuing statistically significant excess in lung cancers was reported.[988]

In the past 15 years there has been substantial research on the inhalation dosimetry for formaldehyde in rodents and primates by the CIIT Centers for Health Research (formerly the Chemical Industry Institute of Toxicology), with a focus on use of rodent data for refinement of the quantitative cancer dose-response assessment.[989,990,991] CIIT's risk assessment of formaldehyde incorporated mechanistic and dosimetric information on formaldehyde. However, it should be noted that recent research published by EPA indicates that when two-stage modeling assumptions are varied, resulting dose-response estimates can vary by several orders of magnitude.[992,993,994,995] These findings are not supportive of interpreting the CIIT model results as providing a conservative (health protective) estimate of human risk.[996] EPA research also examined the contribution of the two-stage modeling for formaldehyde towards characterizing the relative weights of key events in the mode-of-action of a carcinogen. For example, the model-based inference in the published CIIT study that formaldehyde's direct mutagenic action is not relevant to the compound's tumorigenicity was found not to hold under variations of modeling assumptions.[997]

Based on the developments of the last decade, in 2004, the working group of the IARC concluded that formaldehyde is carcinogenic to humans (Group 1), on the basis of sufficient evidence in humans and sufficient evidence in experimental animals - a higher classification than previous IARC evaluations. After reviewing the currently available epidemiological evidence, the IARC (2006) characterized the human evidence for formaldehyde carcinogenicity as "sufficient," based upon the data on nasopharyngeal cancers; the epidemiologic evidence on leukemia was characterized as "strong."[998] EPA is reviewing the recent work cited above from the NCI and NIOSH, as well as the analysis by the CIIT Centers for Health Research and other studies, as part of a reassessment of the human hazard and dose-response associated with formaldehyde.

Formaldehyde exposure also causes a range of noncancer health effects, including irritation of the eyes (burning and watering of the eyes), nose and throat. Effects from repeated exposure in humans include respiratory tract irritation, chronic bronchitis and nasal epithelial lesions such as metaplasia and loss of cilia. Animal studies suggest that formaldehyde may also cause airway inflammation – including eosinophil infiltration into the airways. There are several studies that suggest that formaldehyde may increase the risk of asthma – particularly in the young.[999,1000]

### 3.5.5.5 Acetaldehyde

Acetaldehyde is classified in EPA's IRIS database as a probable human carcinogen, based on nasal tumors in rats, and is considered toxic by the inhalation, oral, and intravenous routes.[1001] Acetaldehyde is reasonably anticipated to be a human carcinogen by the U.S. DHHS in the 11th Report on Carcinogens and is classified as possibly carcinogenic to humans (Group

2B) by the IARC.[1002,1003] EPA is currently conducting a reassessment of cancer risk from inhalation exposure to acetaldehyde.

The primary noncancer effects of exposure to acetaldehyde vapors include irritation of the eyes, skin, and respiratory tract.[1004] In short-term (4 week) rat studies, degeneration of olfactory epithelium was observed at various concentration levels of acetaldehyde exposure.[1005,1006] Data from these studies were used by EPA to develop an inhalation reference concentration. Some asthmatics have been shown to be a sensitive subpopulation to decrements in functional expiratory volume (FEV1 test) and bronchoconstriction upon acetaldehyde inhalation.[1007] The agency is currently conducting a reassessment of the health hazards from inhalation exposure to acetaldehyde.

### 3.5.5.6 Acrolein

EPA determined in 2003 that the human carcinogenic potential of acrolein could not be determined because the available data were inadequate. No information was available on the carcinogenic effects of acrolein in humans and the animal data provided inadequate evidence of carcinogenicity.[1008] The IARC determined in 1995 that acrolein was not classifiable as to its carcinogenicity in humans.[1009]

Acrolein is extremely acrid and irritating to humans when inhaled, with acute exposure resulting in upper respiratory tract irritation, mucus hypersecretion and congestion. The intense irritancy of this carbonyl has been demonstrated during controlled tests in human subjects, who suffer intolerable eye and nasal mucosal sensory reactions within minutes of exposure.[1010] These data and additional studies regarding acute effects of human exposure to acrolein are summarized in EPA's 2003 IRIS Human Health Assessment for acrolein.[1011] Evidence available from studies in humans indicate that levels as low as 0.09 ppm (0.21 mg/m$^3$) for five minutes may elicit subjective complaints of eye irritation with increasing concentrations leading to more extensive eye, nose and respiratory symptoms.[1012] Lesions to the lungs and upper respiratory tract of rats, rabbits, and hamsters have been observed after subchronic exposure to acrolein.[1013] Acute exposure effects in animal studies report bronchial hyper-responsiveness.[1014] In a recent study, the acute respiratory irritant effects of exposure to 1.1 ppm acrolein were more pronounced in mice with allergic airway disease by comparison to non-diseased mice which also showed decreases in respiratory rate.[1015] Based on these animal data and demonstration of similar effects in humans (i.e., reduction in respiratory rate), individuals with compromised respiratory function (e.g., emphysema, asthma) are expected to be at increased risk of developing adverse responses to strong respiratory irritants such as acrolein.

### 3.5.6.7 Peroxyacetyl nitrate (PAN)

PAN has not been evaluated by EPA's IRIS program. Information regarding the potential carcinogenicity of PAN is limited. As noted in the EPA air quality criteria document for ozone and related photochemical oxidants, cytogenetic studies indicate that PAN is not a potent mutagen, clastogen (a compound that can cause breaks in chromosomes), or DNA-damaging agent in mammalian cells either in vivo or in vitro. Some studies suggest that PAN may be a weak bacterial mutagen at high concentrations much higher than exist in present urban atmospheres.[1016]

Effects of ground-level smog causing intense eye irritation have been attributed to photochemical oxidants, including PAN.[1017] Animal toxicological information on the inhalation effects of the non-ozone oxidants has been limited to a few studies on PAN. Acute exposure to levels of PAN can cause changes in lung morphology, behavioral modifications, weight loss, and susceptibility to pulmonary infections. Human exposure studies indicate minor pulmonary function effects at high PAN concentrations, but large inter-individual variability precludes definitive conclusions.[1018]

### 3.5.6.8 Naphthalene

Naphthalene is found in small quantities in gasoline and diesel fuels. Naphthalene emissions have been measured in larger quantities in both gasoline and diesel exhaust compared with evaporative emissions from mobile sources, indicating it is primarily a product of combustion. EPA released an external review draft of a reassessment of the inhalation carcinogenicity of naphthalene based on a number of recent animal carcinogenicity studies.[1019] The draft reassessment completed external peer review.[1020] Based on external peer review comments received, additional analyses are being undertaken. This external review draft does not represent official agency opinion and was released solely for the purposes of external peer review and public comment. The National Toxicology Program listed naphthalene as "reasonably anticipated to be a human carcinogen" in 2004 on the basis of bioassays reporting clear evidence of carcinogenicity in rats and some evidence of carcinogenicity in mice.[1021] California EPA has released a new risk assessment for naphthalene, and the IARC has reevaluated naphthalene and re-classified it as Group 2B: possibly carcinogenic to humans.[1022] Naphthalene also causes a number of chronic non-cancer effects in animals, including abnormal cell changes and growth in respiratory and nasal tissues.[1023]

### 3.5.6.9 N-Hexane

N-Hexane is associated with polyneuropathy in humans. Effects observed in rodents include nasal lesions as well as neurotoxic effects. EPA has developed a reference concentration of 700 $\mu g/m^3$ from a study of peripheral neuropathy.[1024] There is inadequate data to assess its carcinogenic potential.

### 3.5.6.10 Pesticides

There are potential toxicity concerns with volatilization of pesticide active ingredients,[1025] in addition to concerns with contamination of foods and drinking water. Furthermore, raising acreage under corn production may increase the quantity of pesticide products in use. As the domestic corn supply grows between the years of 2005 and 2022, the percentage of corn used for ethanol production in the US is expected to increase, though the agricultural impacts of this shifting of crop production domestically are anticipated to be small. Whether there is the potential for adverse human health effects from any increase in pesticide use associated with increased corn production domestically warrants further assessment. Additional information on pesticides and health effects is included in Section 6.1 of this RIA.

### 3.5.6.11 Other Air Toxics

In addition to the compounds described above, other compounds in gaseous hydrocarbon and PM emissions from vehicles will be affected by today's proposed action. Mobile source air toxic compounds that will potentially be impacted include ethylbenzene, polycyclic organic matter, propionaldehyde, toluene, and xylene. Information regarding the health effects of these compounds can be found in EPA's IRIS database.[1026]

## 3.6 Environmental Effects

In this section we discuss some of the environmental effects of PM and its precursors, such as visibility impairment, atmospheric deposition, and materials damage and soiling. We also discuss environmental effects associated with the presence of ozone in the ambient air, such as impacts on plants, including trees, agronomic crops and urban ornamentals.

### 3.6.1 Visibility Degradation

Emissions from LD vehicles contribute to poor visibility in the U.S. through their primary $PM_{2.5}$ and secondary $PM_{2.5}$ precursor emissions. These airborne particles degrade visibility by scattering and absorbing light. Good visibility increases the quality of life where individuals live and work, and where they engage in recreational activities.

The U.S. Government places special emphasis on protecting visibility in national parks and wilderness areas. Section 169 of the Clean Air Act requires the U.S. Government to address existing visibility impairment and future visibility impairment in the national parks exceeding 6,000 acres, and wilderness areas exceeding 5,000 acres, which are categorized as mandatory class I federal areas (62 FR 38680, July 18, 1997).[NNNNNNNNN] Figure 3.6-1 shows the location of the 156 mandatory class I federal areas.

### 3.6.1.1 Visibility Monitoring

In conjunction with the U.S. National Park Service, the U.S. Forest Service, other Federal land managers, and State organizations in the U.S., the U.S. EPA has supported visibility monitoring in national parks and wilderness areas since 1988. The monitoring network was originally established at 20 sites, but it has now been expanded to 110 sites that represent all but one of the 156 mandatory class I federal areas across the country (see Figure3.6-1). This long-term visibility monitoring network is known as IMPROVE (Interagency Monitoring of Protected Visual Environments).

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[NNNNNNNNN] These areas are defined in section 162 of the Act as those national parks exceeding 6,000 acres, wilderness areas and memorial parks exceeding 5,000 acres, and all international parks which were in existence on August 7, 1977.

IMPROVE provides direct measurement of fine particles that contribute to visibility impairment. The IMPROVE network employs aerosol measurements at all sites, and optical and scene measurements at some of the sites. Aerosol measurements are taken for $PM_{10}$ and $PM_{2.5}$ mass, and for key constituents of $PM_{2.5}$, such as sulfate, nitrate, organic and elemental carbon, soil dust, and several other elements. Measurements for specific aerosol constituents are used to calculate "reconstructed" aerosol light extinction by multiplying the mass for each constituent by its empirically-derived scattering and/or absorption efficiency, with adjustment for the relative humidity. Knowledge of the main constituents of a site's light extinction "budget" is critical for source apportionment and control strategy development. Optical measurements are used to directly measure light extinction or its components. Such measurements are taken principally with either a transmissometer, which measures total light extinction, or a nephelometer, which measures particle scattering (the largest human-caused component of total extinction). Scene characteristics are typically recorded three times daily with 35 millimeter photography and are used to determine the quality of visibility conditions (such as effects on color and contrast) associated with specific levels of light extinction as measured under both direct and aerosol-related methods. Directly measured light extinction is used under the IMPROVE protocol to cross check that the aerosol-derived light extinction levels are reasonable in establishing current visibility conditions. Aerosol-derived light extinction is used to document spatial and temporal trends and to determine how proposed changes in atmospheric constituents would affect future visibility conditions.

Annual average visibility conditions (reflecting light extinction due to both anthropogenic and non-anthropogenic sources) vary regionally across the U.S. The rural East generally has higher levels of impairment than remote sites in the West, with the exception of urban-influenced sites such as San Gorgonio Wilderness (CA) and Point Reyes National Seashore (CA), which have annual average levels comparable to certain sites in the Northeast. Regional differences are illustrated by Figures 4-39a and 4-39b in the Air Quality Criteria Document for Particulate Matter, which show that, for Class I areas, visibility levels on the 20% haziest days in the West are about equal to levels on the 20% best days in the East.[1027]

Higher visibility impairment levels in the East are due to generally higher concentrations of anthropogenic fine particles, particularly sulfates, and higher average relative humidity levels. In fact, sulfates account for 60-86% of the haziness in eastern sites.[1028] Aerosol light extinction due to sulfate on the 20% haziest days is significantly larger in eastern Class I areas as compared to western areas (Figures 4-40a and 4-40b in the Air Quality Criteria Document for Particulate Matter).[1029] With the exception of remote sites in the northwestern U.S., visibility is typically worse in the summer months. This is particularly true in the Appalachian region, where average light extinction in the summer exceeds the annual average by 40%.[1030]

### 3.6.1.2 Addressing Visibility in the U.S.

The U.S. EPA is pursuing a two-part strategy to address visibility. First, to address the welfare effects of PM on visibility, EPA set secondary $PM_{2.5}$ standards which act in conjunction with the establishment of a regional haze program. In setting this secondary standard, EPA has concluded that $PM_{2.5}$ causes adverse effects on visibility in various locations, depending on PM concentrations and factors such as chemical composition and average relative humidity. Second, section 169 of the Clean Air Act provides additional authority to address existing visibility impairment and prevent future visibility impairment in the 156 mandatory Class I federal areas (62 FR 38680-81, July 18, 1997). In July 1999, the regional haze rule (64 FR 35714) was put in place to protect the visibility in mandatory Class I federal areas. Visibility can be said to be impaired in both $PM_{2.5}$ nonattainment areas and mandatory Class I federal areas.[OOOOOOOOO]

**Figure 3.6-1: Mandatory Class I Areas in the U.S.**

## 3.6.2 Particulate Matter Deposition

Particulate matter contributes to adverse effects on vegetation and ecosystems, and to soiling and materials damage. These welfare effects result predominately from exposure to excess amounts of specific chemical species, regardless of their source or predominant form (particle, gas or liquid). Reflecting this fact, the PM AQCD concludes that regardless of size fractions, particles containing nitrates and sulfates have the greatest potential for widespread environmental significance, while effects are also related to other chemical constituents found in

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[ooooooooo] As mentioned above, the EPA recently amended the PM NAAQS, making the secondary NAAQS equal, in all respects, to the primary standards for both $PM_{2.5}$ and $PM_{10}$, (71 FR 61144, Oct. 17, 2006). In February 2009, the D.C. Circuit Court remanded the secondary standards for fine particles, based on EPA's failure to adequately explain why setting the secondary PM2.5 NAAQS equivalent to the primary standards provided the required protection for public welfare including protection from visibility impairment.

ambient PM, such as trace metals and organics. The following characterizations of the nature of these welfare effects are based on the information contained in the PM AQCD and PM Staff Paper.[1031,1032]

### 3.6.2.1 Deposition of Nitrogen and Sulfur

Nitrogen and sulfur interactions in the environment are highly complex. Both are essential, and sometimes limiting, nutrients needed for growth and productivity. Excesses of nitrogen or sulfur can lead to acidification, nutrient enrichment, and eutrophication.[1033]

The process of acidification affects both freshwater aquatic and terrestrial ecosystems. Acid deposition causes acidification of sensitive surface waters. The effects of acid deposition on aquatic systems depend largely upon the ability of the ecosystem to neutralize the additional acid. As acidity increases, aluminum leached from soils and sediments, flows into lakes and streams and can be toxic to both terrestrial and aquatic biota. The lower pH concentrations and higher aluminum levels resulting from acidification make it difficult for some fish and other aquatic organisms to survive, grow, and reproduce. Research on effects of acid deposition on forest ecosystems has come to focus increasingly on the biogeochemical processes that affect uptake, retention, and cycling of nutrients within these ecosystems. Decreases in available base cations from soils are at least partly attributable to acid deposition. Base cation depletion is a cause for concern because of the role these ions play in acid neutralization and, because calcium, magnesium and potassium are essential nutrients for plant growth and physiology. Changes in the relative proportions of these nutrients, especially in comparison with aluminum concentrations, have been associated with declining forest health.

At current ambient levels, risks to vegetation from short-term exposures to dry deposited particulate nitrate or sulfate are low. However, when found in acid or acidifying deposition, such particles do have the potential to cause direct leaf injury. Specifically, the responses of forest trees to acid precipitation (rain, snow) include accelerated weathering of leaf cuticular surfaces, increased permeability of leaf surfaces to toxic materials, water, and disease agents; increased leaching of nutrients from foliage; and altered reproductive processes—all which serve to weaken trees so that they are more susceptible to other stresses (e.g., extreme weather, pests, pathogens). Acid deposition with levels of acidity associated with the leaf effects described above are currently found in some locations in the eastern U.S.[1034] Even higher concentrations of acidity can be present in occult depositions (e.g., fog, mist or clouds) which more frequently impacts higher elevations. Thus, the risk of leaf injury occurring from acid deposition in some areas of the eastern U.S**.** is high. Nitrogen deposition has also been shown to impact ecosystems in the western U.S. A study conducted in the Columbia River Gorge National Scenic Area (CRGNSA), located along a portion of the Oregon/Washington border, indicates that lichen communities in the CRGNSA have shifted to a higher proportion of nitrophilous species and the nitrogen content of lichen tissue is elevated.[1035] Lichens are sensitive indicators of nitrogen deposition effects to terrestrial ecosystems and the lichen studies in the Columbia River Gorge clearly show that ecological effects from air pollution are occurring.

Some of the most significant detrimental effects associated with excess nitrogen deposition are those associated with a syndrome known as nitrogen saturation. These effects include: (1) decreased productivity, increased mortality, and/or shifts in plant community composition, often leading to decreased biodiversity in many natural habitats wherever atmospheric reactive nitrogen deposition increases significantly above background and critical thresholds are exceeded; (2) leaching of excess nitrate and associated base cations from soils into streams, lakes, and rivers, and mobilization of soil aluminum; and (3) fluctuation of ecosystem processes such as nutrient and energy cycles through changes in the functioning and species composition of beneficial soil organisms.[1036]

In the U.S. numerous forests now show severe symptoms of nitrogen saturation. These forests include: the northern hardwoods and mixed conifer forests in the Adirondack and Catskill Mountains of New York; the red spruce forests at Whitetop Mountain, Virginia, and Great Smoky Mountains National Park, North Carolina; mixed hardwood watersheds at Fernow Experimental Forest in West Virginia; American beech forests in Great Smoky Mountains National Park, Tennessee; mixed conifer forests and chaparral watersheds in southern California and the southwestern Sierra Nevada in Central California; the alpine tundra/subalpine conifer forests of the Colorado Front Range; and red alder forests in the Cascade Mountains in Washington.

Excess nutrient inputs into aquatic ecosystems (i.e. streams, rivers, lakes, estuaries or oceans) either from direct atmospheric deposition, surface runoff, or leaching from nitrogen saturated soils into ground or surface waters can contribute to conditions of severe water oxygen depletion; eutrophication and algae blooms; altered fish distributions, catches, and physiological states; loss of biodiversity; habitat degradation; and increases in the incidence of disease.

Atmospheric deposition of nitrogen is a significant source of total nitrogen to many estuaries in the United States. The amount of nitrogen entering estuaries that is ultimately attributable to atmospheric deposition is not well-defined. On an annual basis, atmospheric nitrogen deposition may contribute significantly to the total nitrogen load, depending on the size and location of the watershed. In addition, episodic nitrogen inputs, which may be ecologically important, may play a more important role than indicated by the annual average concentrations. Estuaries in the U.S. that suffer from nitrogen enrichment often experience a condition known as eutrophication. Symptoms of eutrophication include changes in the dominant species of phytoplankton, low levels of oxygen in the water column, fish and shellfish kills, outbreaks of toxic alga, and other population changes which can cascade throughout the food web. In addition, increased phytoplankton growth in the water column and on surfaces can attenuate light causing declines in submerged aquatic vegetation, which serves as an important habitat for many estuarine fish and shellfish species.

Severe and persistent eutrophication often directly impacts human activities. For example, losses in the nation's fishery resources may be directly caused by fish kills associated with low dissolved oxygen and toxic blooms. Declines in tourism occur when low dissolved oxygen causes noxious smells and floating mats of algal blooms create unfavorable aesthetic conditions. Risks to human health increase when the toxins from algal blooms accumulate in edible fish and shellfish, and when toxins become airborne, causing respiratory problems due to inhalation. According to a NOAA report, more than half of the nation's estuaries have moderate to high expressions of at least one of these symptoms – an indication that eutrophication is well developed in more than half of U.S. estuaries.[1037]

#### 3.6.2.2 Materials Damage and Soiling

The effects of the deposition of atmospheric pollution, including ambient PM, on materials are related to both physical damage and impaired aesthetic qualities. The deposition of PM (especially sulfates and nitrates) can physically affect materials, adding to the effects of natural weathering processes, by potentially promoting or accelerating the corrosion of metals, by degrading paints, and by deteriorating building materials such as concrete and limestone. Only chemically active fine particles or hygroscopic coarse particles contribute to these physical effects. In addition, the deposition of ambient PM can reduce the aesthetic appeal of buildings and culturally important articles through soiling. Particles consisting primarily of carbonaceous compounds cause soiling of commonly used building materials and culturally important items such as statues and works of art.

### 3.6.3 Impacts of Ozone on Vegetation

The Air Quality Criteria Document for Ozone and related Photochemical Oxidants notes that "ozone affects vegetation throughout the United States, impairing crops, native vegetation, and ecosystems more than any other air pollutant".[1038] Like carbon dioxide ($CO_2$) and other gaseous substances, ozone enters plant tissues primarily through apertures (stomata) in leaves in a process called "uptake."[1039] Once sufficient levels of ozone (a highly reactive substance), or its reaction products, reaches the interior of plant cells, it can inhibit or damage essential cellular components and functions, including enzyme activities, lipids, and cellular membranes, disrupting the plant's osmotic (i.e., water) balance and energy utilization patterns.[1040,1041] This damage is commonly manifested as visible foliar injury, such as chlorotic or necrotic spots, increased leaf senescence (accelerated leaf aging) and/or reduced photosynthesis. All these effects reduce a plant's capacity to form carbohydrates, which are the primary form of energy used by plants.[1042] If enough tissue becomes damaged from these effects, a plant's capacity to fix carbon to form carbohydrates, which are the primary form of energy used by plants, is reduced,[1043] while plant respiration increases. With fewer resources available, the plant reallocates existing resources away from root growth and storage, above ground growth or yield, and reproductive processes, toward leaf repair and maintenance, leading to reduced growth and/or reproduction. Studies have shown that plants stressed in these ways may exhibit a general loss of vigor, which can lead to secondary impacts that modify plants' responses to other environmental factors. Specifically, plants may become more sensitive to other air pollutants, more susceptible to disease, insect attack, harsh weather (e.g., drought, frost) and other environmental stresses. Furthermore, there is evidence that ozone can interfere with the formation of mycorrhiza, essential symbiotic fungi associated with the roots of most terrestrial plants, by reducing the amount of carbon available for transfer from the host to the symbiont.[1044,1045]

This ozone damage may or may not be accompanied by visible injury on leaves, and likewise, visible foliar injury may or may not be a symptom of the other types of plant damage described above. When visible injury is present, it is commonly manifested as chlorotic or necrotic spots, and/or increased leaf senescence (accelerated leaf aging). Because ozone damage can consist of visible injury to leaves, it can also reduce the aesthetic value of ornamental vegetation and trees in urban landscapes, and negatively affects scenic vistas in protected natural areas.

Ozone can produce both acute and chronic injury in sensitive species depending on the concentration level and the duration of the exposure. Ozone effects also tend to accumulate over the growing season of the plant, so that even lower concentrations experienced for a longer duration have the potential to create chronic stress on sensitive vegetation. Not all plants, however, are equally sensitive to ozone. Much of the variation in sensitivity between individual plants or whole species is related to the plant's ability to regulate the extent of gas exchange via leaf stomata (e.g., avoidance of ozone uptake through closure of stomata).[1046,1047,1048] Other resistance mechanisms may involve the intercellular production of detoxifying substances. Several biochemical substances capable of detoxifying ozone have been reported to occur in plants, including the antioxidants ascorbate and glutathione. After injuries have occurred, plants may be capable of repairing the damage to a limited extent.[1049]

Because of the differing sensitivities among plants to ozone, ozone pollution can also exert a selective pressure that leads to changes in plant community composition. Given the range of plant sensitivities and the fact that numerous other environmental factors modify plant uptake and response to ozone, it is not possible to identify threshold values above which ozone is consistently toxic for all plants. The next few paragraphs present additional information on ozone damage to trees, ecosystems, agronomic crops and urban ornamentals.

Ozone also has been conclusively shown to cause discernible injury to forest trees.[1050,1051] In terms of forest productivity and ecosystem diversity, ozone may be the pollutant with the greatest potential for regional-scale forest impacts. Studies have demonstrated repeatedly that ozone concentrations commonly observed in polluted areas can have substantial impacts on plant function.[1052,1053]

Because plants are at the base of the food web in many ecosystems, changes to the plant community can affect associated organisms and ecosystems (including the suitability of habitats that support threatened or endangered species and below ground organisms living in the root zone). Ozone impacts at the community and ecosystem level vary widely depending upon numerous factors, including concentration and temporal variation of tropospheric ozone, species composition, soil properties and climatic factors.[1054] In most instances, responses to chronic or recurrent exposure in forested ecosystems are subtle and not observable for many years. These injuries can cause stand-level forest decline in sensitive ecosystems.[1055,1056,1057] It is not yet possible to predict ecosystem responses to ozone with much certainty; however, considerable knowledge of potential ecosystem responses has been acquired through long-term observations in highly damaged forests in the United States.

Laboratory and field experiments have also shown reductions in yields for agronomic crops exposed to ozone, including vegetables (e.g., lettuce) and field crops (e.g., cotton and wheat). The most extensive field experiments, conducted under the National Crop Loss Assessment Network (NCLAN) examined 15 species and numerous cultivars. The NCLAN results show that "several economically important crop species are sensitive to ozone levels typical of those found in the Unites States."[1058] In addition, economic studies have shown reduced economic benefits as a result of predicted reductions in crop yields associated with observed ozone levels.[1059,1060,1061]

Urban ornamentals represent an additional vegetation category likely to experience some degree of negative effects associated with exposure to ambient ozone levels. It is estimated that more than $20 billion (1990 dollars) are spent annually on landscaping using ornamentals, both by private property owners/tenants and by governmental units responsible for public areas.[1062] This is therefore a potentially costly environmental effect. However, in the absence of adequate exposure-response functions and economic damage functions for the potential range of effects relevant to these types of vegetation, no direct quantitative analysis has been conducted.

Air pollution can have noteworthy cumulative impacts on forested ecosystems by affecting regeneration, productivity, and species composition.[1063] In the U.S., ozone in the lower atmosphere is one of the pollutants of primary concern. Ozone injury to forest plants can be diagnosed by examination of plant leaves. Foliar injury is usually the first visible sign of injury to plants from ozone exposure and indicates impaired physiological processes in the leaves.[1064]

In the U.S. this indicator is based on data from the U.S. Department of Agriculture (USDA) Forest Service Forest Inventory and Analysis (FIA) program. As part of its Phase 3 program, formerly known as Forest Health Monitoring, FIA examines ozone injury to ozone-sensitive plant species at ground monitoring sites in forest land across the country. For this indicator, forest land does not include woodlots and urban trees. Sites are selected using a systematic sampling grid, based on a global sampling design.[1065,1066] At each site that has at least 30 individual plants of at least three ozone-sensitive species and enough open space to ensure that sensitive plants are not protected from ozone exposure by the forest canopy, FIA looks for damage on the foliage of ozone-sensitive forest plant species. Monitoring of ozone injury to plants by the USDA Forest Service has expanded over the last 10 years from monitoring sites in 10 states in 1994 to nearly 1,000 monitoring sites in 41 states in 2002.

### 3.6.3.1 Recent Ozone Data for the U.S.

There is considerable regional variation in ozone-related visible foliar injury to sensitive plants in the U.S. The U.S. EPA has developed an environmental indicator based on data from the U.S. Department of Agriculture (USDA) Forest Service Forest Inventory and Analysis (FIA) program which examines ozone injury to ozone-sensitive plant species at ground monitoring sites in forest land across the country (This indicator does not include woodlots and urban trees). Sites are selected using a systematic sampling grid, based on a global sampling design.[1067, 1068] Because ozone injury is cumulative over the course of the growing season, examinations are conducted in July and August, when ozone injury is typically highest. The data underlying the indictor in Figure 3.6-2 are based on averages of all observations collected in 2002, the latest year for which data are publicly available at the time the study was conducted, and are broken down by U.S. EPA Region. Ozone damage to forest plants is classified using a subjective five-category biosite index based on expert opinion, but designed to be equivalent from site to site. Ranges of biosite values translate to no injury, low or moderate foliar injury (visible foliar injury to highly sensitive or moderately sensitive plants, respectively), and high or severe foliar injury, which would be expected to result in tree-level or ecosystem-level responses, respectively.[1069, 1070]

The highest percentages of observed high and severe foliar injury, those which are most likely to be associated with tree or ecosystem-level responses, are primarily found in the Mid-Atlantic and Southeast regions. In EPA Region 3 (which comprises the States of Pennsylvania, West Virginia, Virginia, Delaware, Maryland and Washington D.C.), 12% of ozone-sensitive plants showed signs of high or severe foliar damage, and in Regions 2 (States of New York, New Jersey), and 4 (States of North Carolina, South Carolina, Kentucky, Tennessee, Georgia, Florida, Alabama, and Mississippi) the values were 10% and 7%, respectively. The sum of high and severe ozone injury ranged from 2% to 4% in EPA Region 1 (the six New England States), Region 7 (States of Missouri, Iowa, Nebraska and Kansas), and Region 9 (States of California, Nevada, Hawaii and Arizona). The percentage of sites showing some ozone damage was about 45% in each of these EPA Regions.

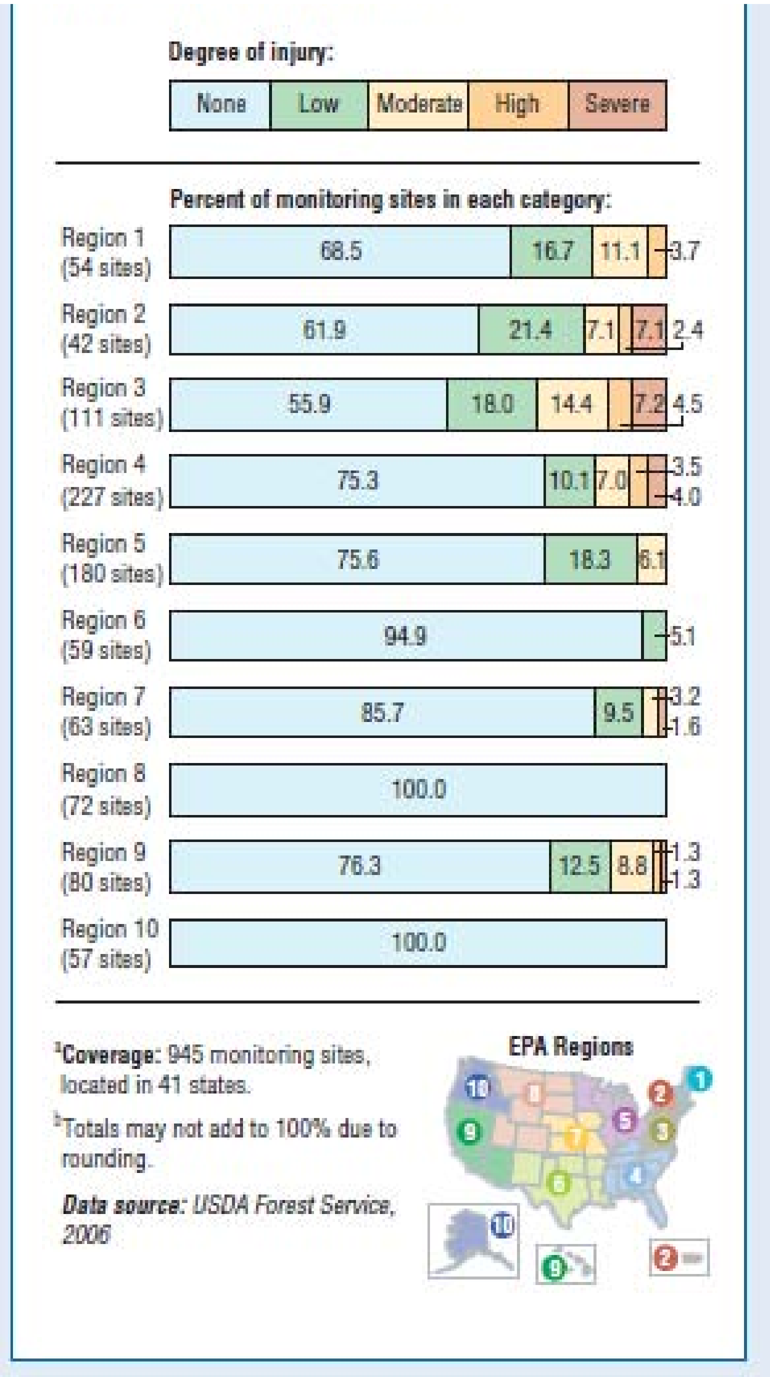


**Figure 3.6-2: Ozone Injury to Forest Plants in U.S. by EPA Regions, 2002**[ab]

#### 3.6.3.1.1 Indicator Limitations

Field and laboratory studies were reviewed to identify the forest plant species in each region that are highly sensitive to ozone air pollution. Other forest plant species, or even genetic variants of the same species, may not be harmed at ozone levels that cause effects on the selected ozone-sensitive species.

Because species distributions vary regionally, different ozone-sensitive plant species were examined in different parts of the country. These target species could vary with respect to ozone sensitivity, which might account for some of the apparent differences in ozone injury among regions of the U.S.

Ozone damage to foliage is considerably reduced under conditions of low soil moisture, but most of the variability in the index (70%) was explained by ozone concentration.[1071] Ozone may have other adverse impacts on plants (e.g., reduced productivity) that do not show signs of visible foliar injury.[1072]

Though FIA has extensive spatial coverage based on a robust sample design, not all forested areas in the U.S. are monitored for ozone injury. Even though the biosite data have been collected over multiple years, most biosites were not monitored over the entire period, so these data cannot provide more than a baseline for future trends.

### 3.6.4 Impacts of Ozone on Forest Health

Air pollution can impact the environment and affect ecological systems, leading to changes in the biological community (both in the diversity of species and the health and vigor of individual species). As an example, many studies have shown that ground-level ozone reduces the health of plants including many commercial and ecologically important forest tree species throughout the United States.[1073]

When ozone is present in the air, it can enter the leaves of plants, where it can cause significant cellular damage. Since photosynthesis occurs in cells within leaves, the ability of the plant to produce energy by photosynthesis can be compromised if enough damage occurs to these cells. If enough tissue becomes damaged it can reduce carbon fixation and increase plant respiration, leading to reduced growth and/or reproduction in young and mature trees. Ozone stress also increases the susceptibility of plants to disease, insects, fungus, and other environmental stressors (e.g., harsh weather). Because ozone damage can consist of visible injury to leaves, it also reduces the aesthetic value of ornamental vegetation and trees in urban landscapes, and negatively affect scenic vistas in protected natural areas.

Assessing the impact of ground-level ozone on forests in the eastern United States involves understanding the risks to sensitive tree species from ambient ozone concentrations and accounting for the prevalence of those species within the forest. As a way to quantify the risks to particular plants from ground-level ozone, scientists have developed ozone-exposure/tree-response functions by exposing tree seedlings to different ozone levels and measuring reductions in growth as "biomass loss." Typically, seedlings are used because they are easy to manipulate and measure their growth loss from ozone pollution. The mechanisms of susceptibility to ozone within the leaves of seedlings and mature trees are identical, though the magnitude of the effect may be higher or lower depending on the tree species. [1074]

Some of the common tree species in the United States that are sensitive to ozone are black cherry (*Prunus serotina*), tulip-poplar (*Liriodendron tulipifera),* eastern white pine (*Pinus strobus).* Ozone-exposure/tree-response functions have been developed for each of these tree species, as well as for aspen (*Populus tremuliodes*), and ponderosa pine (*Pinus ponderosa*).

Other common tree species, such as oak (*Quercus* spp.*)* and hickory (*Carya* spp.), are not nearly as sensitive to ozone. Consequently, with knowledge of the distribution of sensitive species and the level of ozone at particular locations, it is possible to estimate a “biomass loss” for each species across their range.

### 3.6.5 Environmental Effects of Air Toxics

Fuel combustion emissions contribute to ambient levels of pollutants that contribute to adverse effects on vegetation. PAN is a well-established phytotoxicant causing visible injury to leaves that can appear as metallic glazing on the lower surface of leaves with some leafy vegetables exhibiting particular sensitivity (e.g., spinach, lettuce, chard).[1075,1076,1077] PAN has been demonstrated to inhibit photosynthetic and non-photosynthetic processes in plants and retard the growth of young navel orange trees.[1078,1079] In addition to its oxidizing capability, PAN contributes nitrogen to forests and other vegetation via uptake as well as dry and wet deposition to surfaces. As noted above in Section 3.6.2.1, nitrogen deposition can lead to saturation of terrestrial ecosystems and research is needed to understand the impacts of excess nitrogen deposition experienced in some areas of the country on water quality and ecosystems.[1080]

Volatile organic compounds (VOCs), some of which are considered air toxics, have long been suspected to play a role in vegetation damage.[1081] In laboratory experiments, a wide range of tolerance to VOCs has been observed.[1082] Decreases in harvested seed pod weight have been reported for the more sensitive plants, and some studies have reported effects on seed germination, flowering and fruit ripening. Effects of individual VOCs or their role in conjunction with other stressors (e.g., acidification, drought, temperature extremes) have not been well studied. In a recent study of a mixture of VOCs including ethanol and toluene on herbaceous plants, significant effects on seed production, leaf water content and photosynthetic efficiency were reported for some plant species.[1083]

Research suggests an adverse impact of vehicle exhaust on plants, which has in some cases been attributed to aromatic compounds and in other cases to nitrogen oxides.[1084,1085,1086] The impacts of VOCs on plant reproduction may have long-term implications for biodiversity and survival of native species near major roadways. Most of the studies of the impacts of VOCs on vegetation have focused on short-term exposure and few studies have focused on long-term effects of VOCs on vegetation and the potential for metabolites of these compounds to affect herbivores or insects.

# Appendix Chapter 3A: Additional Air Toxics Modeling Results

## 3A.1 Annual Change Ambient Concentration Maps for Air Toxics using the AEO Reference Case

The following section presents maps of annual changes in ambient concentrations of modeled air toxics in 2022 using the AEO 2007 reference case compared to the RFS2 control case.

### 3A.1.1 Acetaldehyde

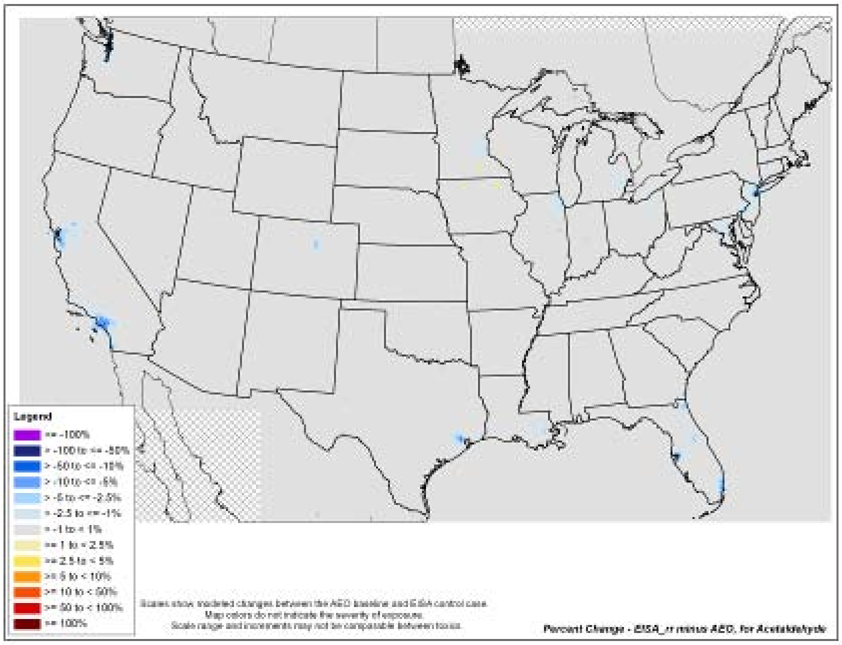


**Figure 3A-1. Acetaldehyde Annual Percent Change in Concentration Between the AEO 2007 Reference Case and the RFS2 Control Case in 2022**

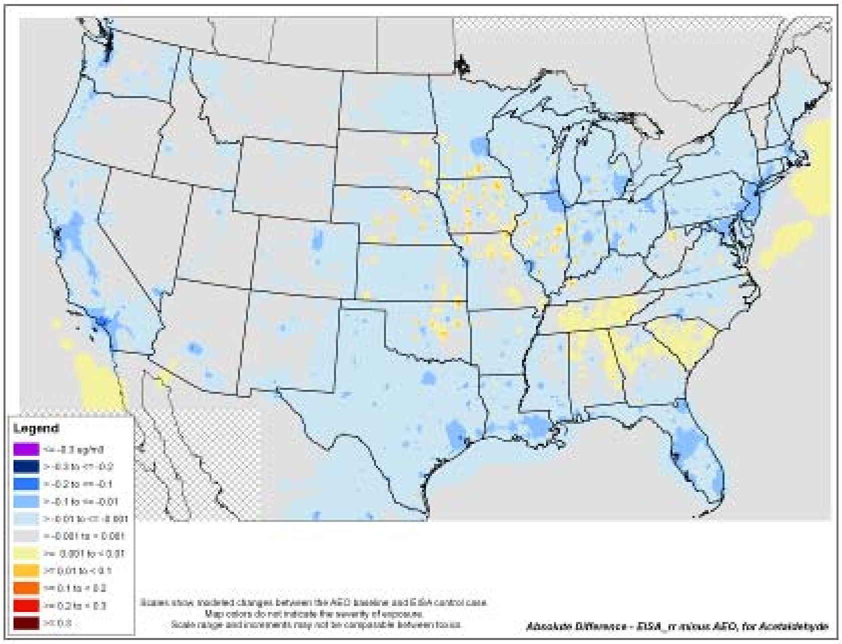


**Figure 3A-2. Acetaldehyde Annual Absolute Change in Concentration Between the AEO 2007 Reference Case and the RFS2 Control Case in 2022**

### 3A.1.2 Formaldehyde

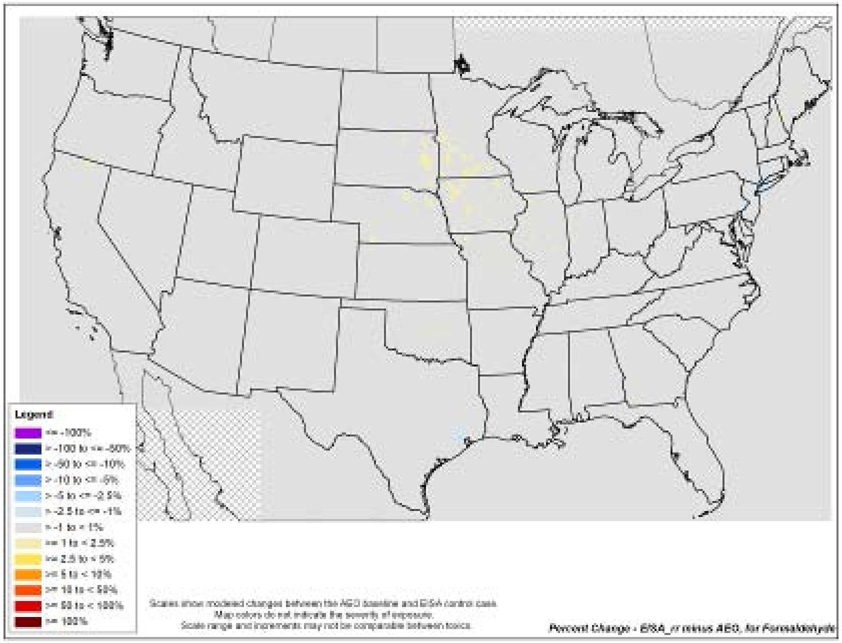
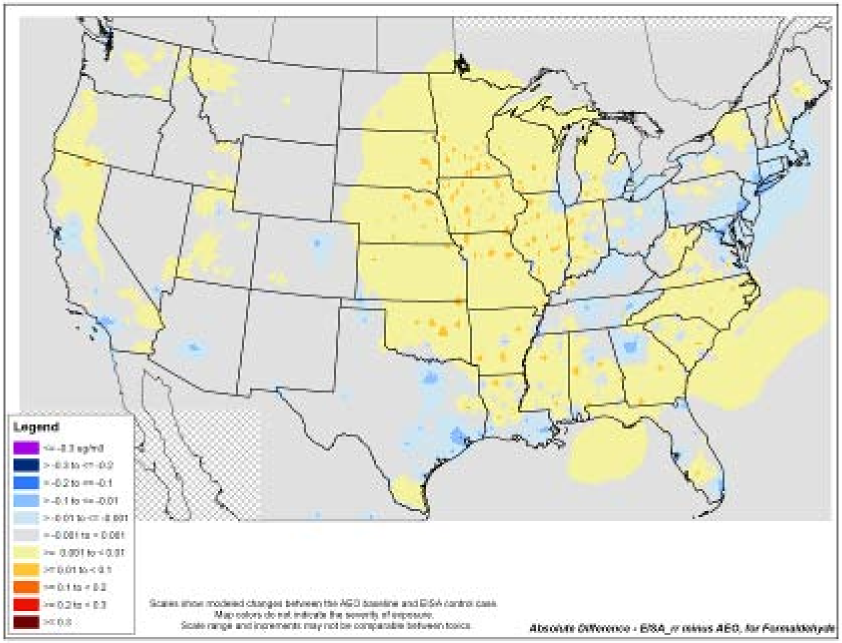


**Figure 3A-3. Formaldehyde Annual Percent Change in Concentration Between the AEO 2007 Reference Case and the RFS2 Control Case in 2022**

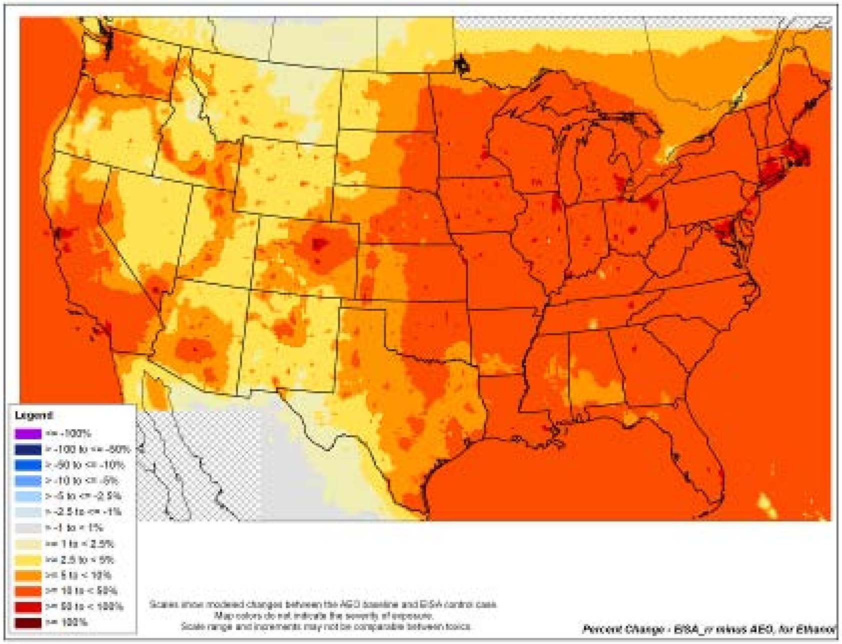


Scales show modeled changes between the AEO baseline and EISA control case.
Map colors do not indicate the severity of exposure.
Scale range and increments may not be comparable between toxics.

*Absolute Difference - EISA_rr minus AEO, for Formaldehyde*

**Figure 3A-4. Formaldehyde Annual Absolute Change in Concentration Between the AEO 2007 Reference Case and the RFS2 Control Case in 2022**

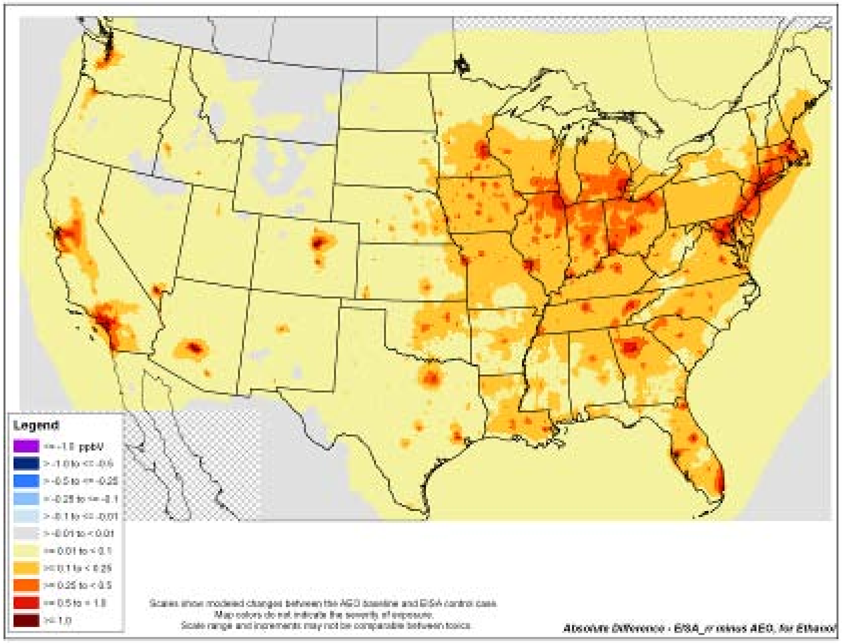
### 3A.1.3 Ethanol



Scales show modeled changes between the AEO baseline and EISA control case.
Map colors do not indicate the severity of exposure.
Scale range and increments may not be comparable between toxics.

*Percent Change - EISA_rr minus AEO, for Ethanol*

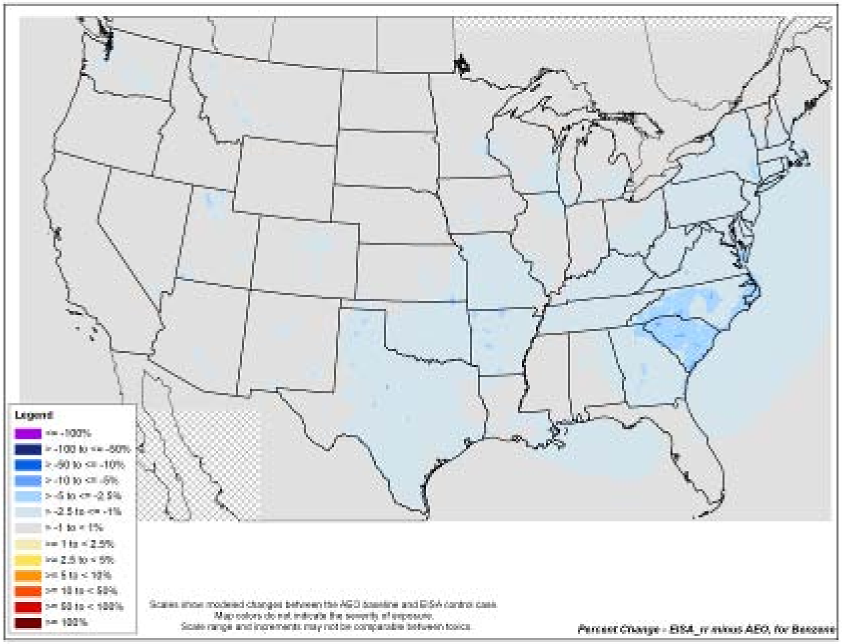
**Figure 3A-5. Ethanol Annual Percent Change in Concentration Between the AEO 2007 Reference Case and the RFS2 Control Case in 2022**



Scales show modeled changes between the AEO baseline and EISA control case.
Map colors do not indicate the severity of exposure.
Scale range and increments may not be comparable between toxics.

Figure 3A-6. Ethanol Annual Absolute Change in Concentration Between the AEO 2007 Reference Case and the RFS2 Control Case in 2022

### 3A.1.4 Benzene



Scales show modeled changes between the AEO baseline and EISA control case.
Map colors do not indicate the severity of exposure.
Scale range and increments may not be comparable between toxics.

Figure 3A-7. Benzene Annual Percent Change in Concentration Between the AEO 2007 Reference Case and the RFS2 Control Case in 2022

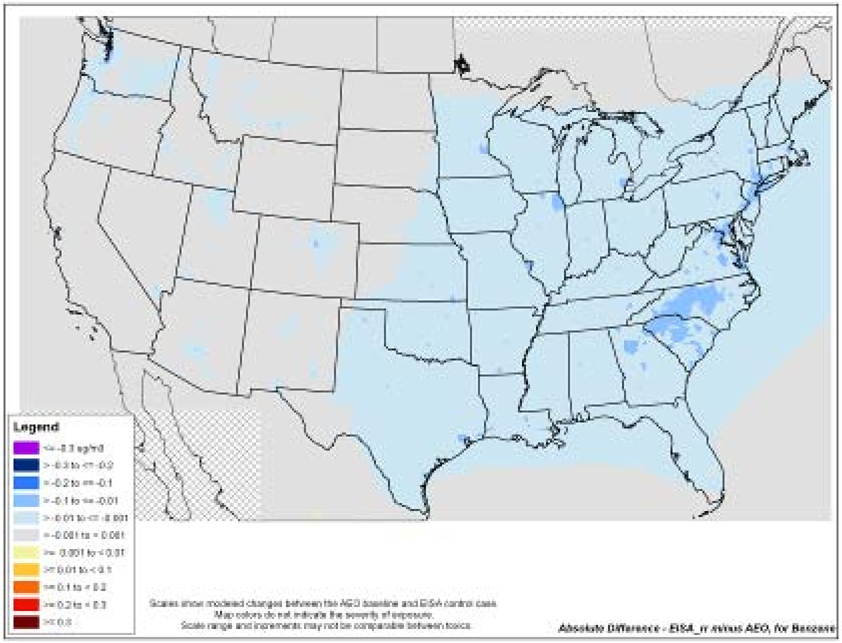


**Figure 3A-8. Benzene Annual Absolute Change in Concentration Between the AEO 2007 Reference Case and the RFS2 Control Case in 2022**

### 3A.1.4 1,3-Butadiene

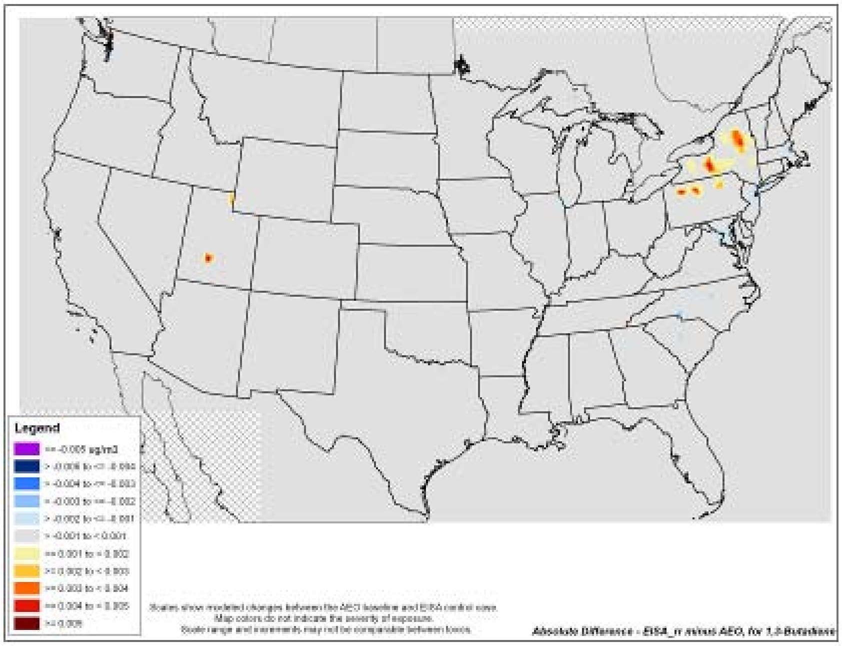


**Figure 3A-9. 1,3-Butadiene Annual Percent Change in Concentration Between the AEO 2007 Reference Case and the RFS2 Control Case in 2022**

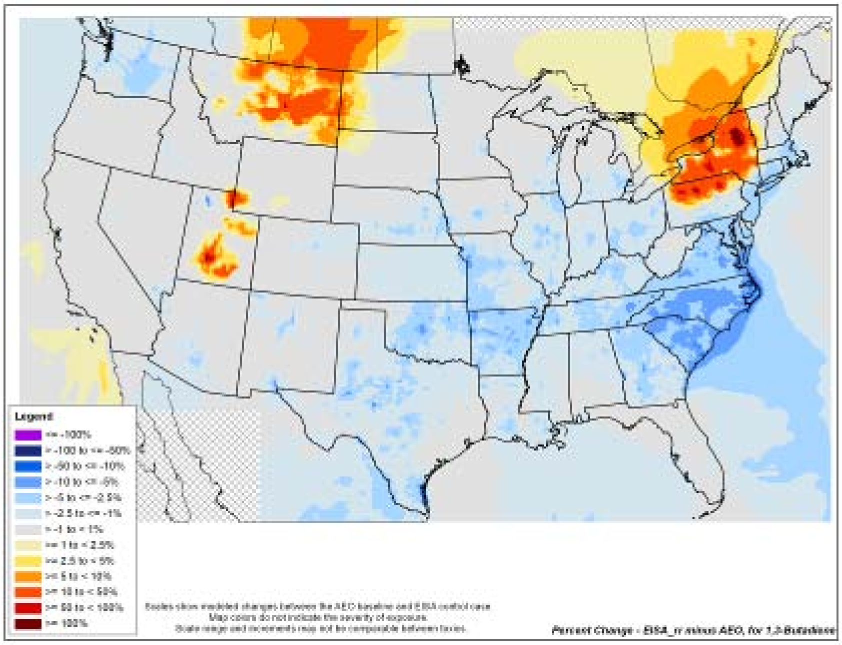


**Figure 3A-10. 1,3-Butadiene Annual Absolute Change in Concentration Between the AEO 2007 Reference Case and the RFS2 Control Case in 2022**

### 3A.1.4 Acrolein

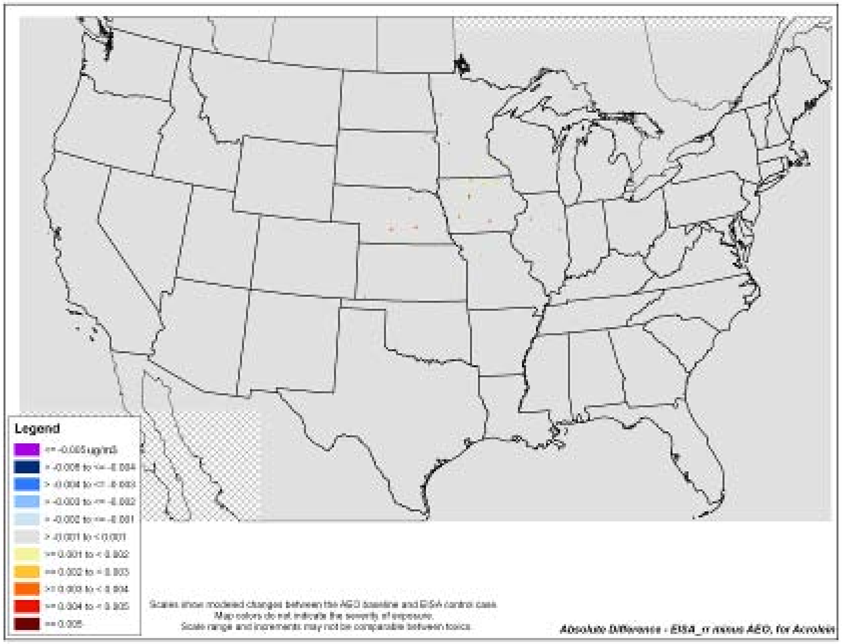


**Figure 3A-11. Acrolein Annual Percent Change in Concentration Between the AEO 2007 Reference Case and the RFS2 Control Case in 2022**

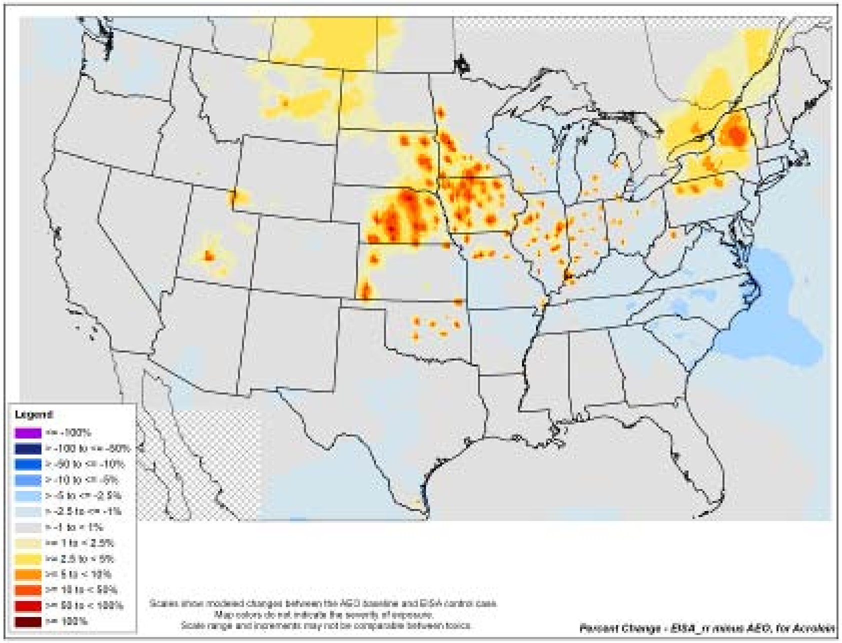


**Figure 3A-12. Acrolein Annual Absolute Change in Concentration Between the AEO 2007 Reference Case and the RFS2 Control Case in 2022**

## 3A.2 Seasonal Change Ambient Concentration Maps for Air Toxics using the RFS1 Reference Case

The following section presents maps of seasonal changes in ambient concentrations of modeled air toxics in 2022 using the RFS1 reference case compared to the RFS2 control case.

### 3A.2.1 Acetaldehyde

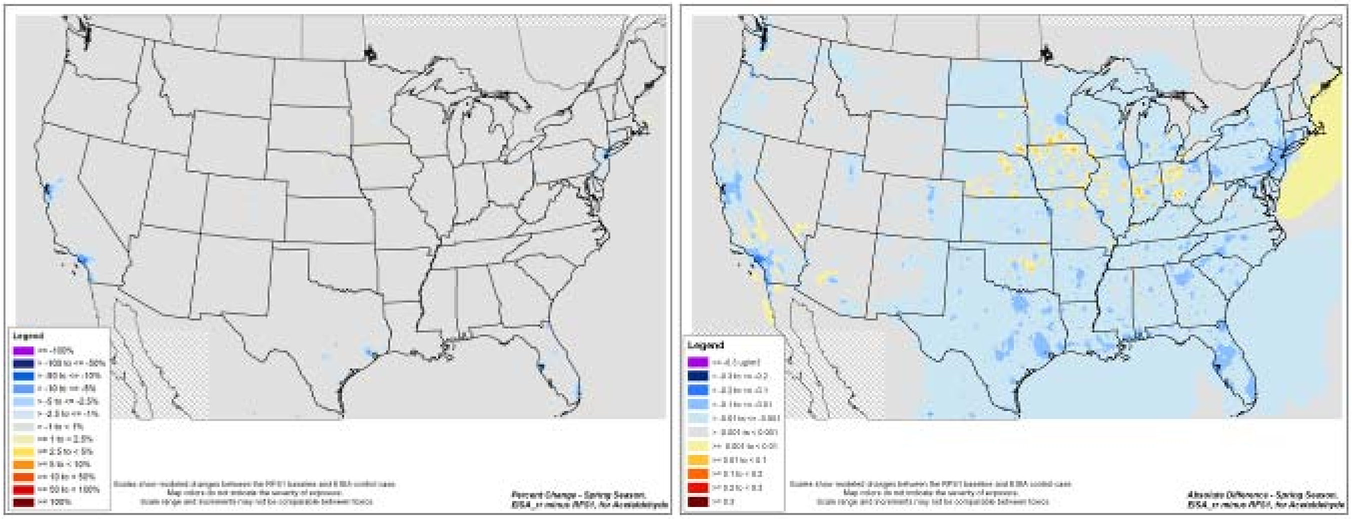


Figure 3A-13. Spring Changes in Acetaldehyde Ambient Concentrations Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (µg/m³)

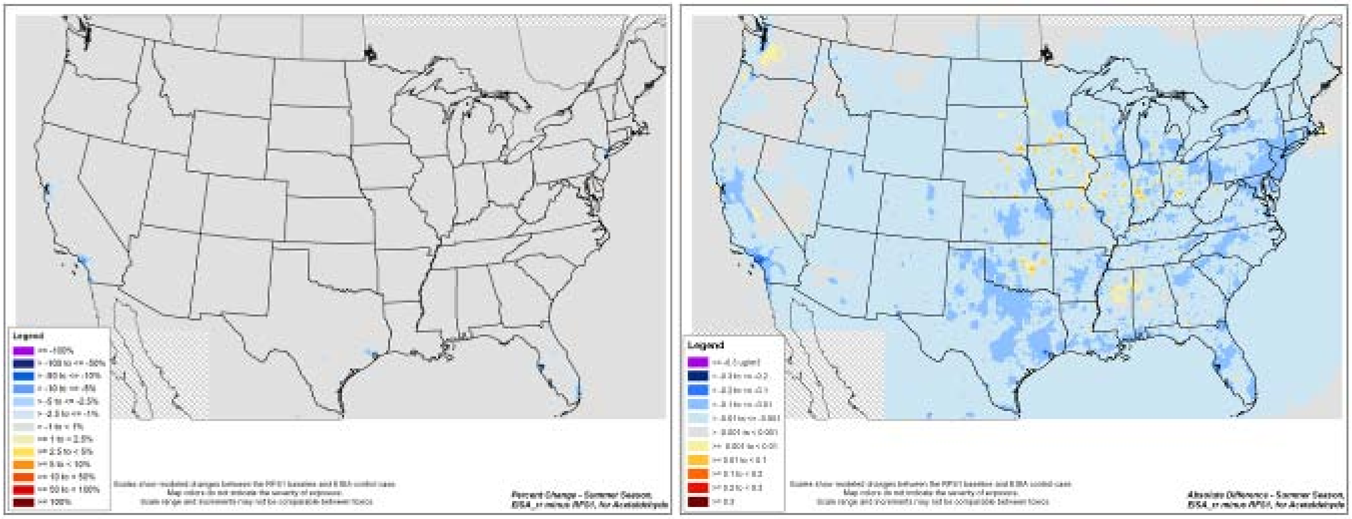


Figure 3A-14. Summer Changes in Acetaldehyde Ambient Concentrations Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (µg/m³)

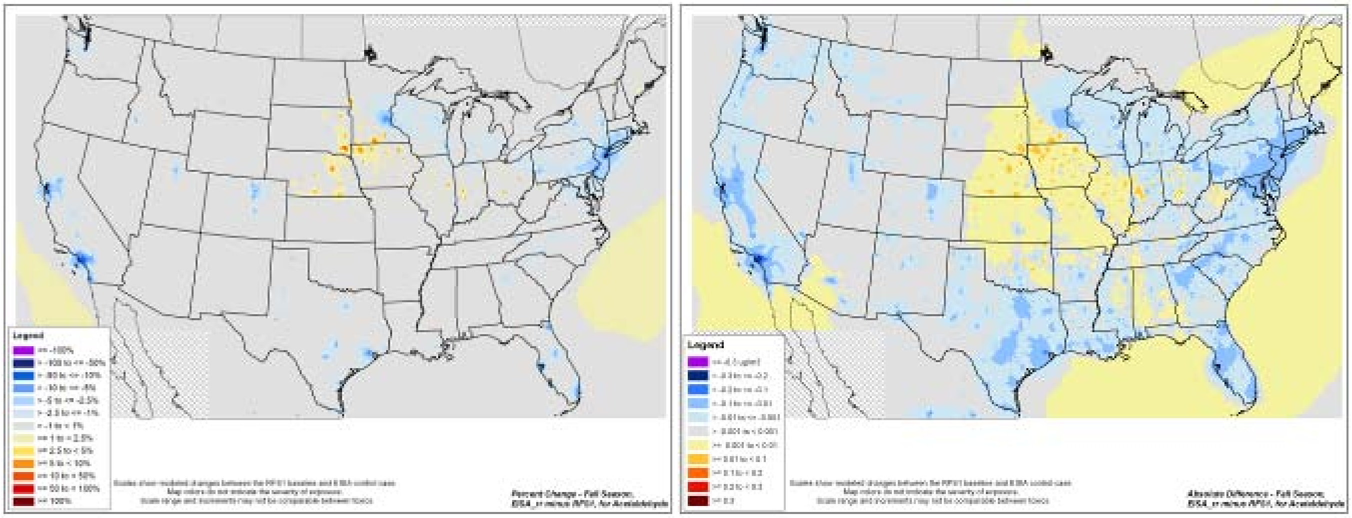


Figure 3A-15. Fall Changes in Acetaldehyde Ambient Concentrations Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (µg/m³)

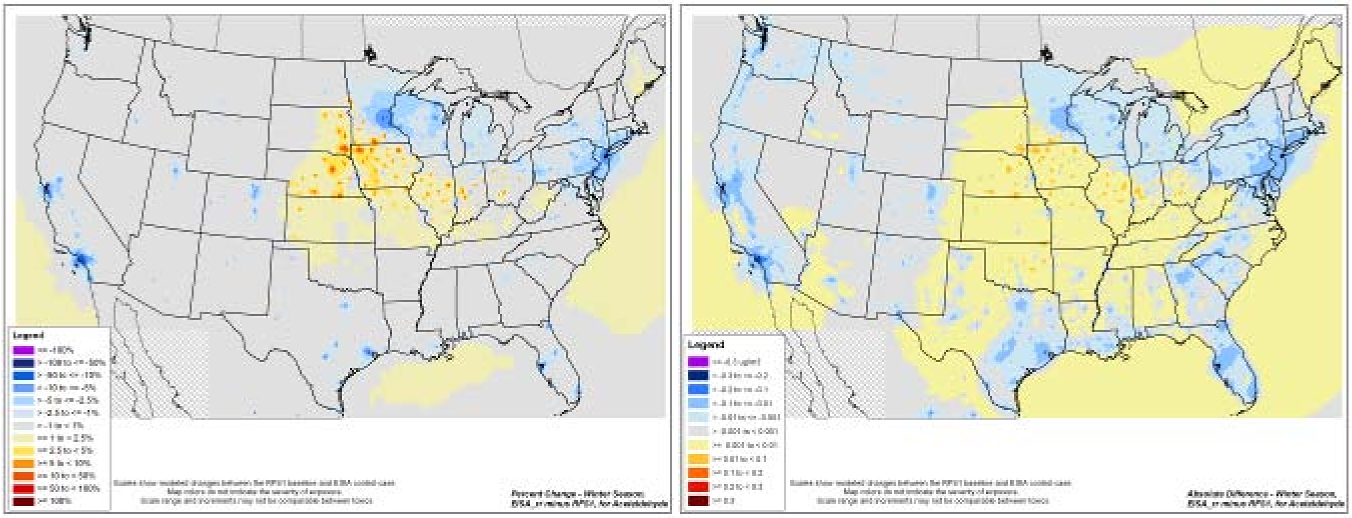


Figure 3A-16. Winter Changes in Acetaldehyde Ambient Concentrations Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (µg/m³)

### 3A.2.2 Formaldehyde

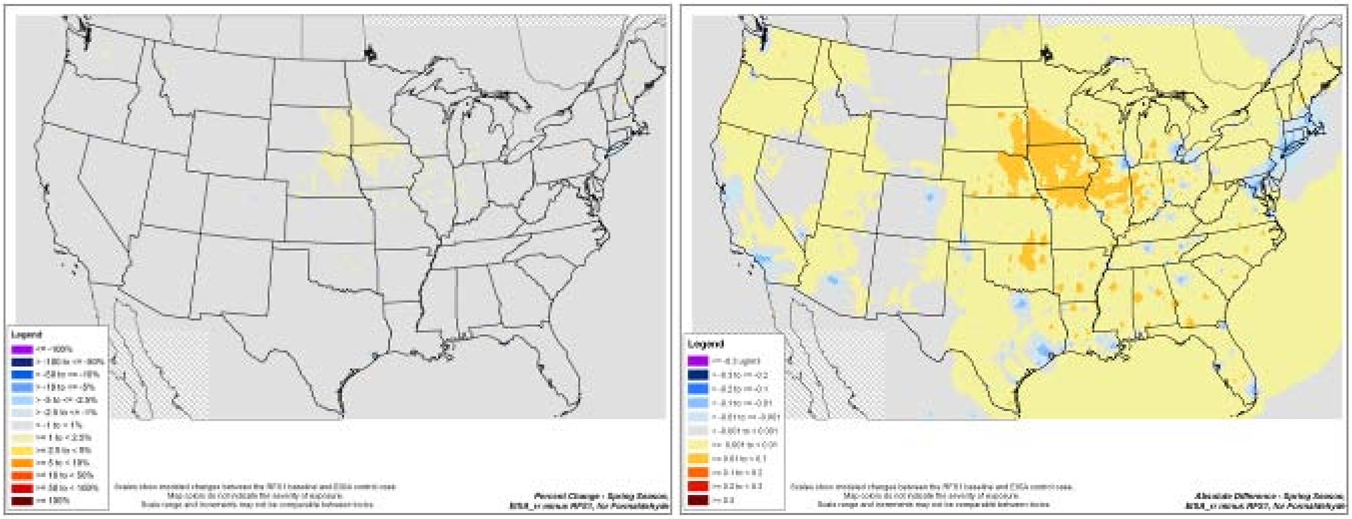


**Figure 3A-17. Spring Changes in Formaldehyde Ambient Concentrations Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (µg/m³)**

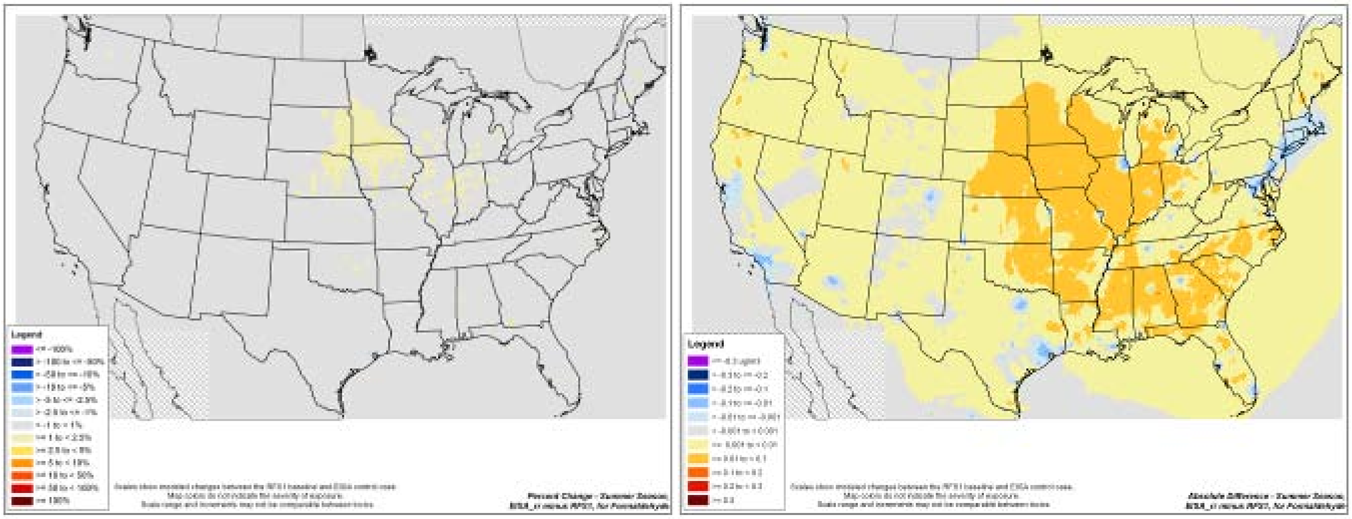


**Figure 3A-18. Summer Changes in Formaldehyde Ambient Concentrations Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (µg/m³)**

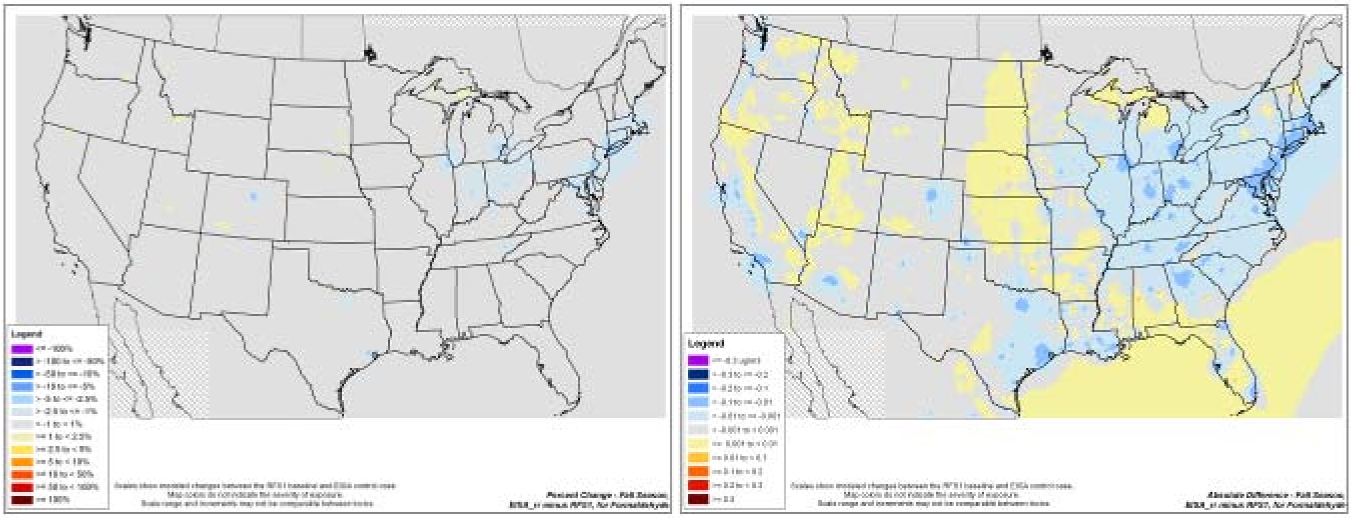


**Figure 3A-19. Fall Changes in Formaldehyde Ambient Concentrations Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (µg/m³)**

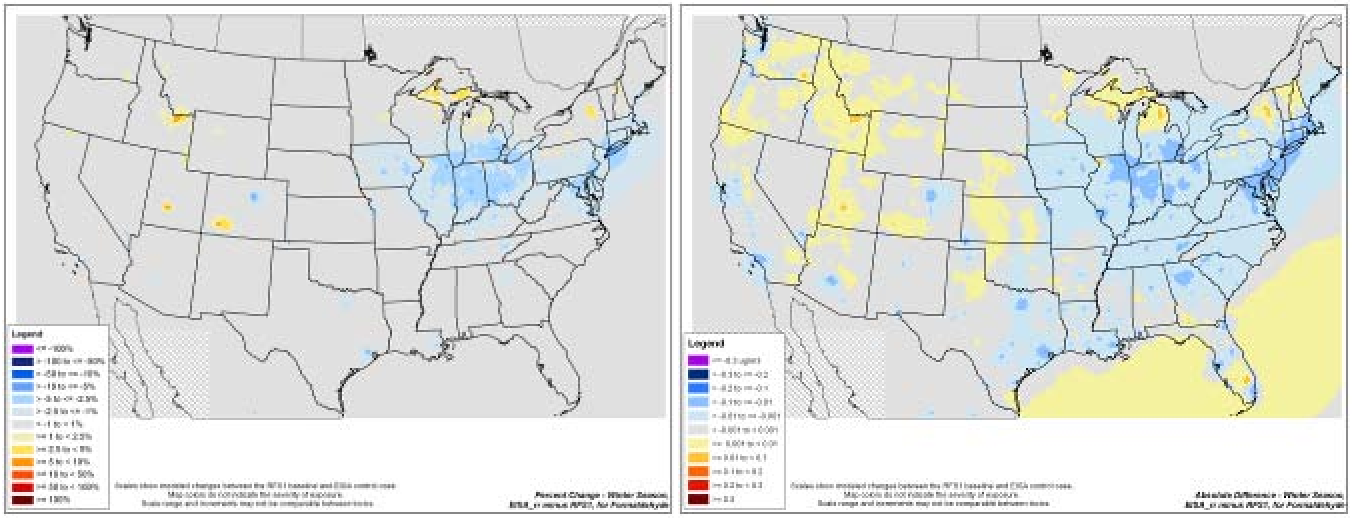


**Figure 3A-20. Winter Changes in Formaldehyde Ambient Concentrations Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (µg/m³)**

### 3A.2.3 Ethanol

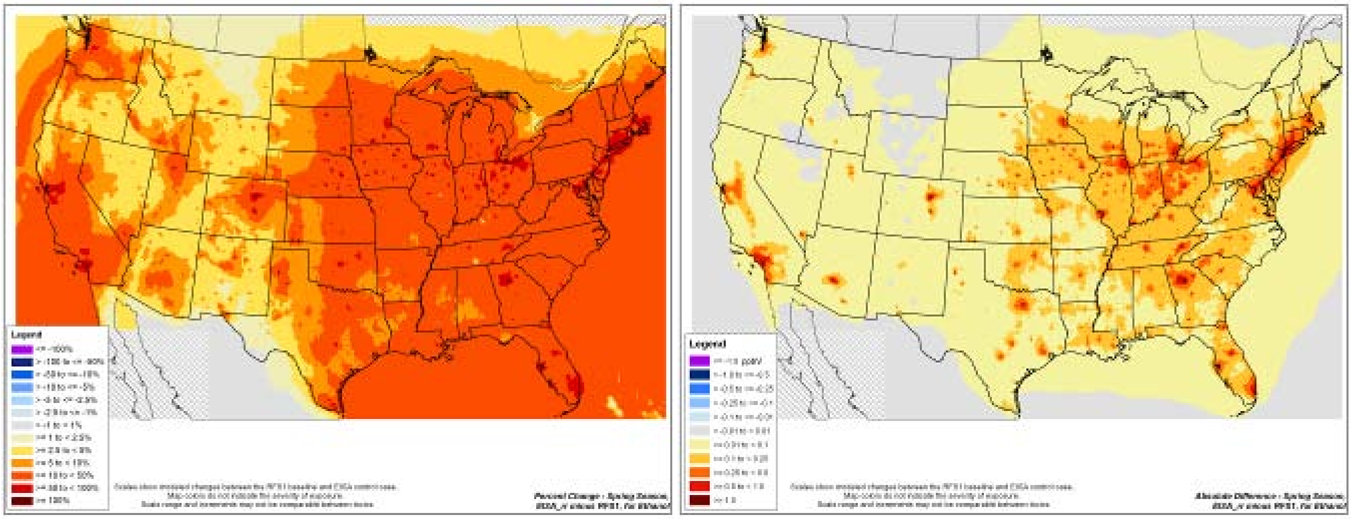


**Figure 3A-21. Spring Changes in Ethanol Ambient Concentrations Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (µg/m³)**

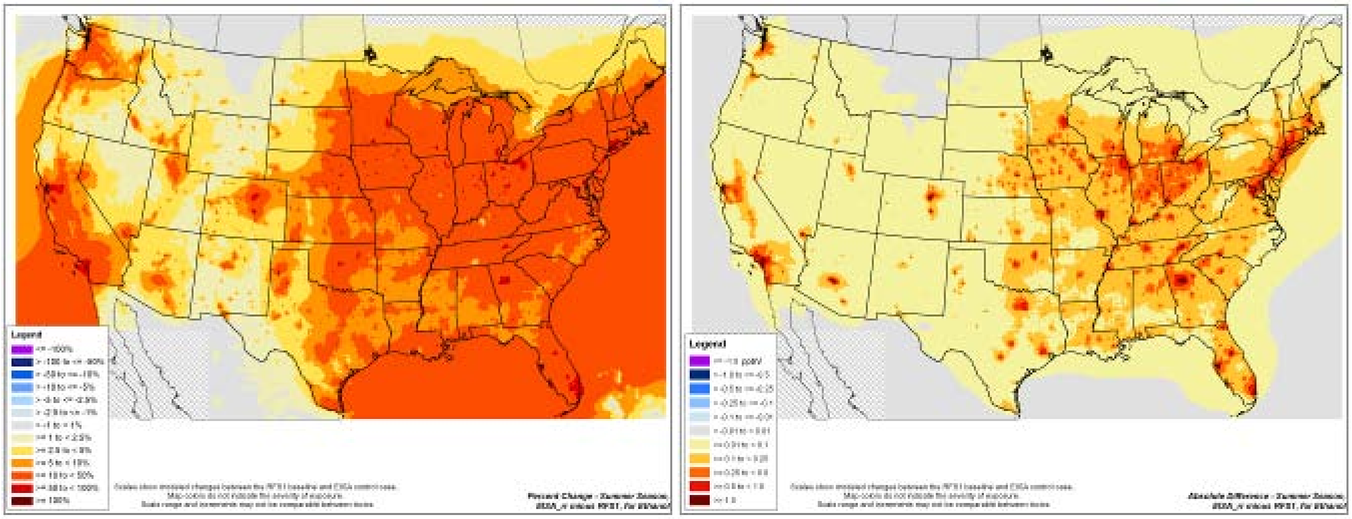


**Figure 3A-22. Summer Changes in Ethanol Ambient Concentrations Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (µg/m³)**

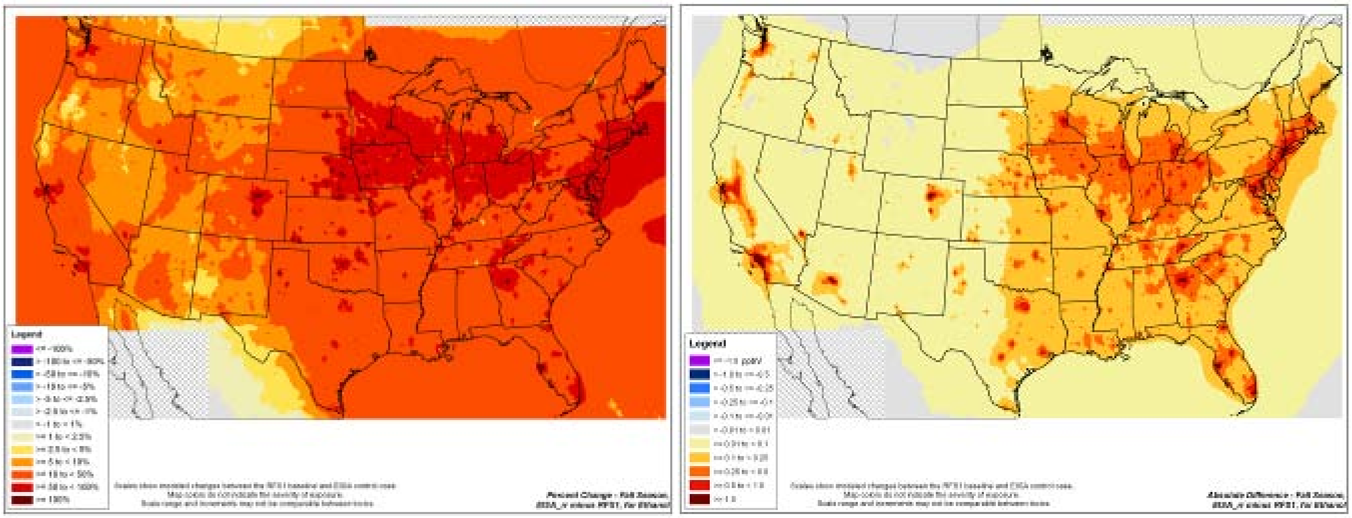


Figure 3A-23. Fall Changes in Ethanol Ambient Concentrations Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (μg/m³)

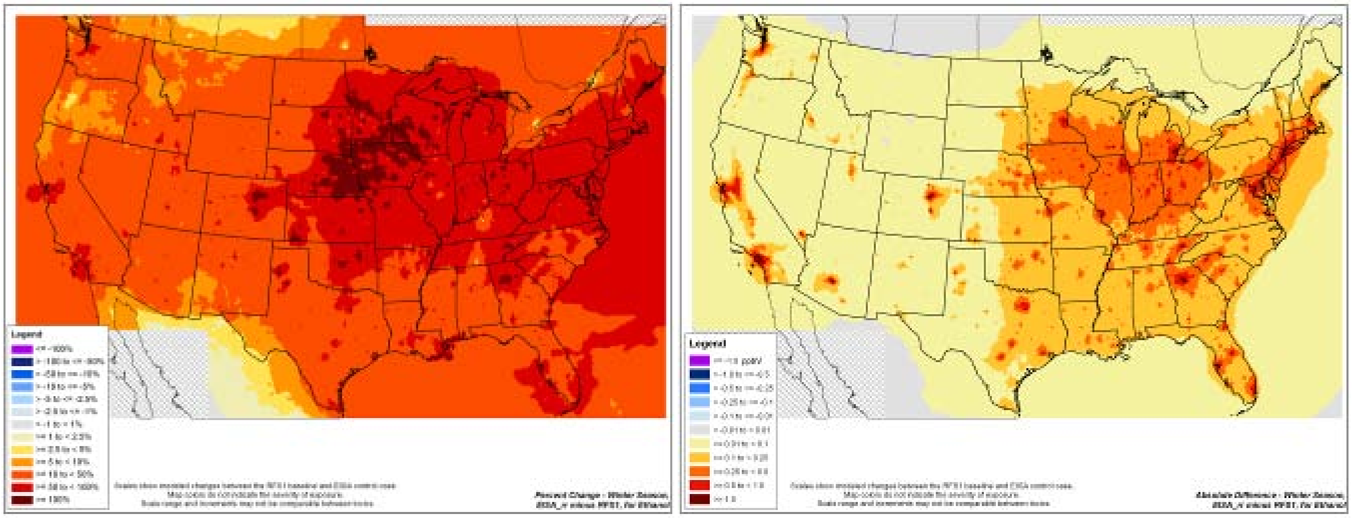


Figure 3A-24. Winter Changes in Ethanol Ambient Concentrations Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (μg/m³)

### 3A.2.4 Benzene

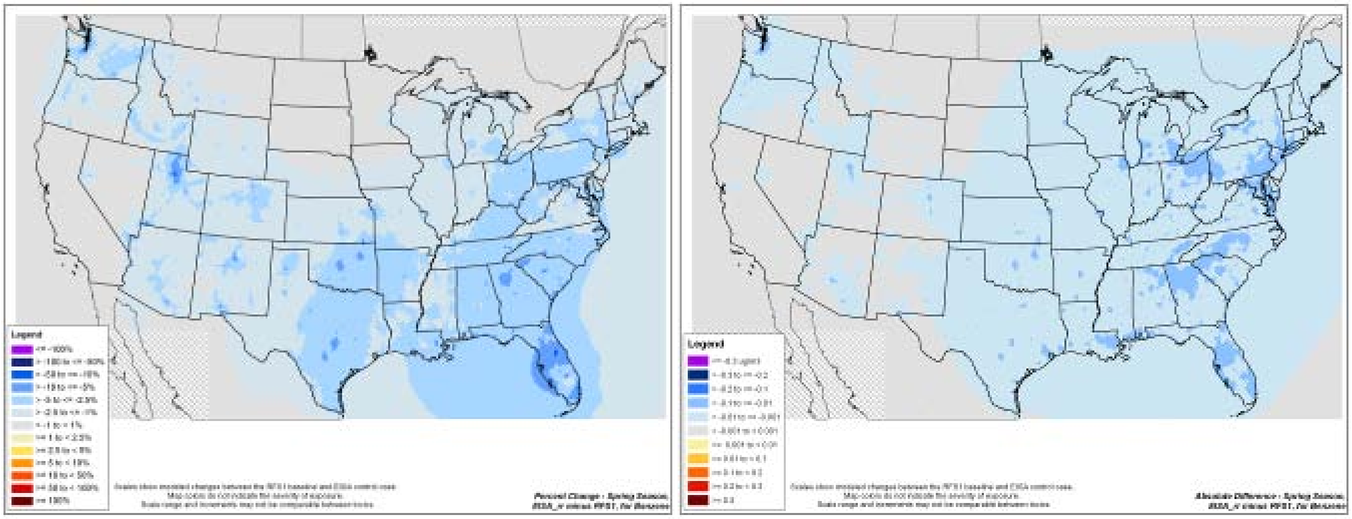


**Figure 3A-25. Spring Changes in Benzene Ambient Concentrations Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (μg/m³)**

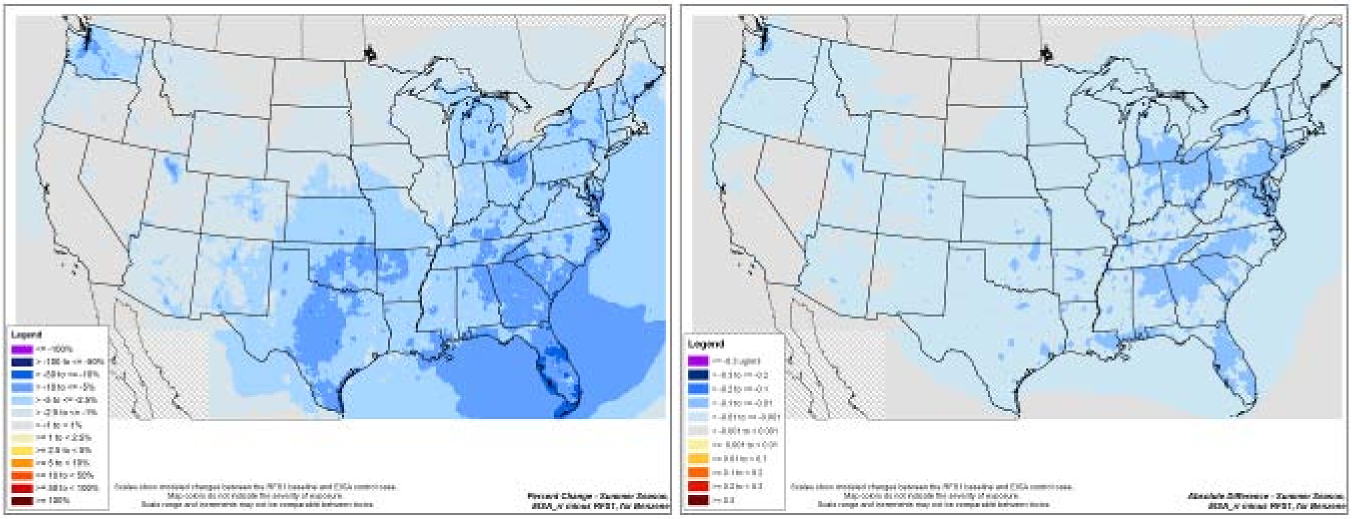


**Figure 3A-26. Summer Changes in Benzene Ambient Concentrations Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (μg/m³)**

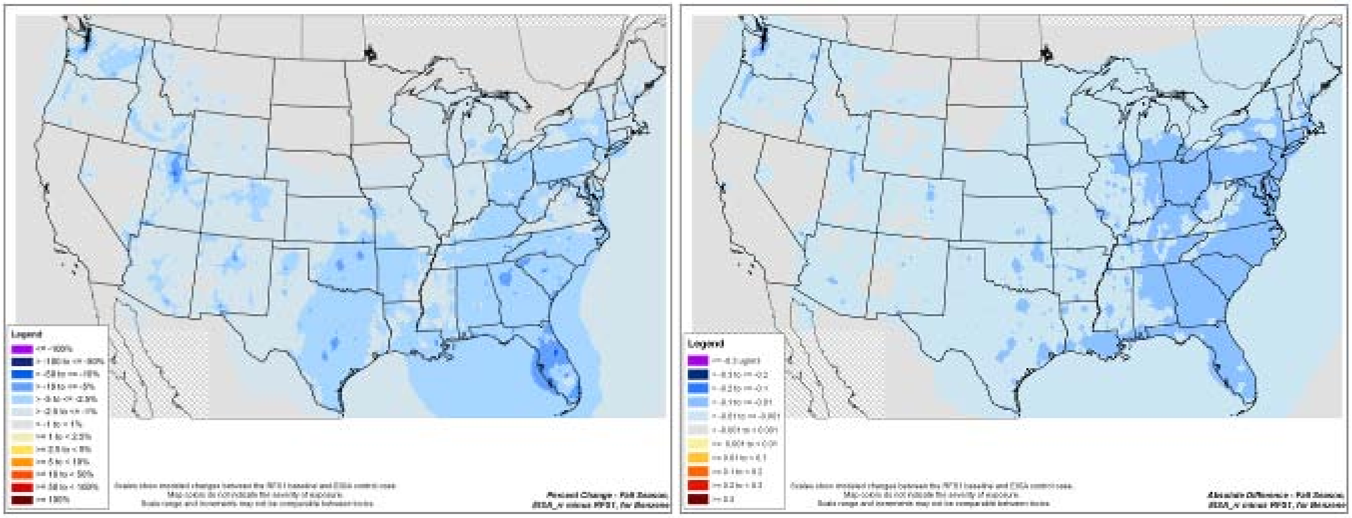


Figure 3A-27.  Fall Changes in Benzene Ambient Concentrations Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (µg/m³)

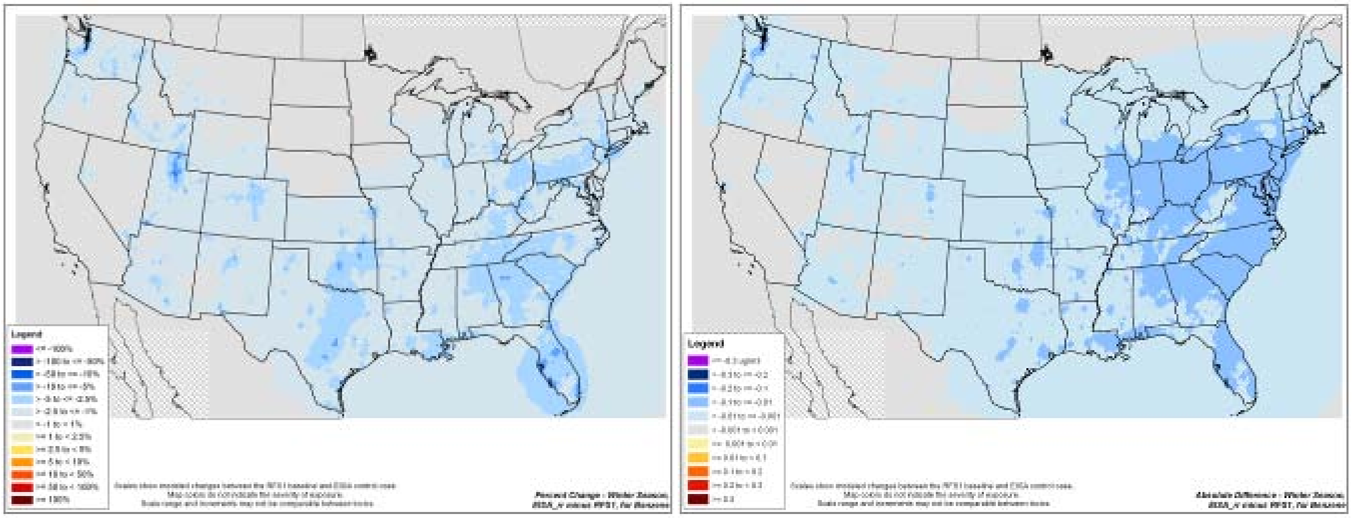


Figure 3A-28.  Winter Changes in Benzene Ambient Concentrations Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (µg/m³)

### 3A.2.5 1,3-Butadiene

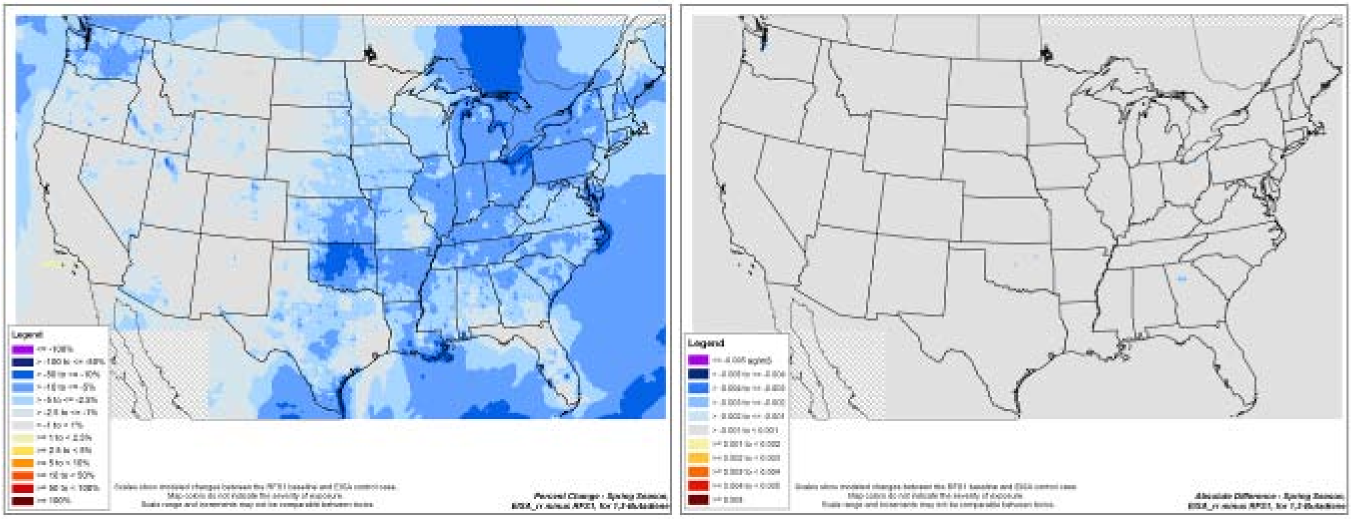


**Figure 3A-29. Spring Changes in 1,3-Butadiene Ambient Concentrations Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (µg/m³)**

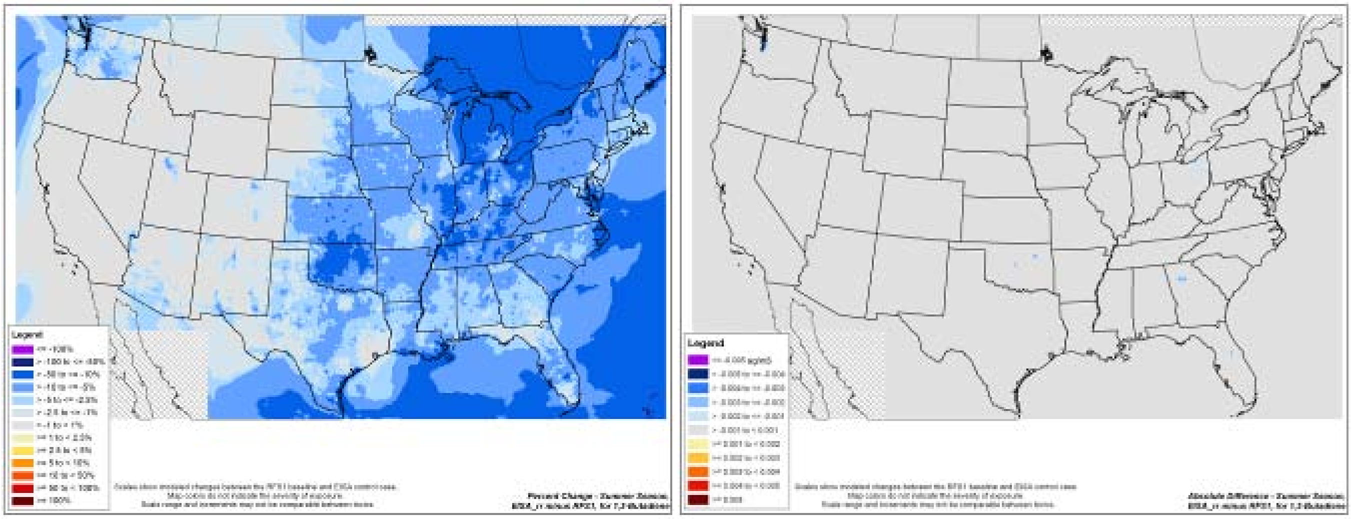


**Figure 3A-30. Summer Changes in 1,3-Butadiene Ambient Concentrations Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (µg/m³)**

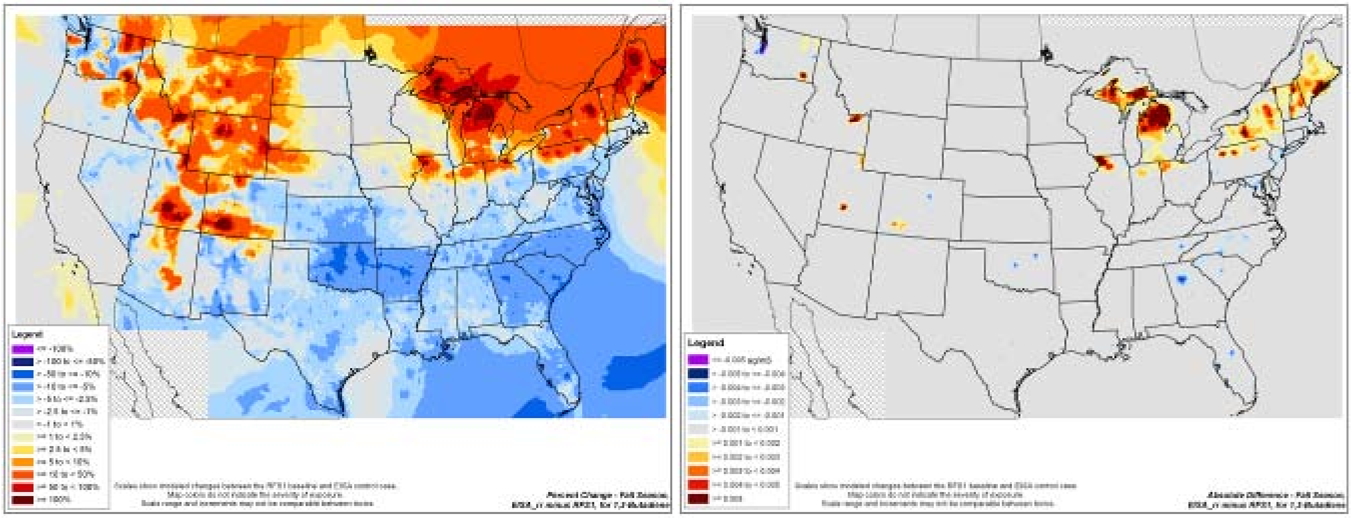


Figure 3A-31. Fall Changes in 1,3-Butadiene Ambient Concentrations Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (µg/m³)

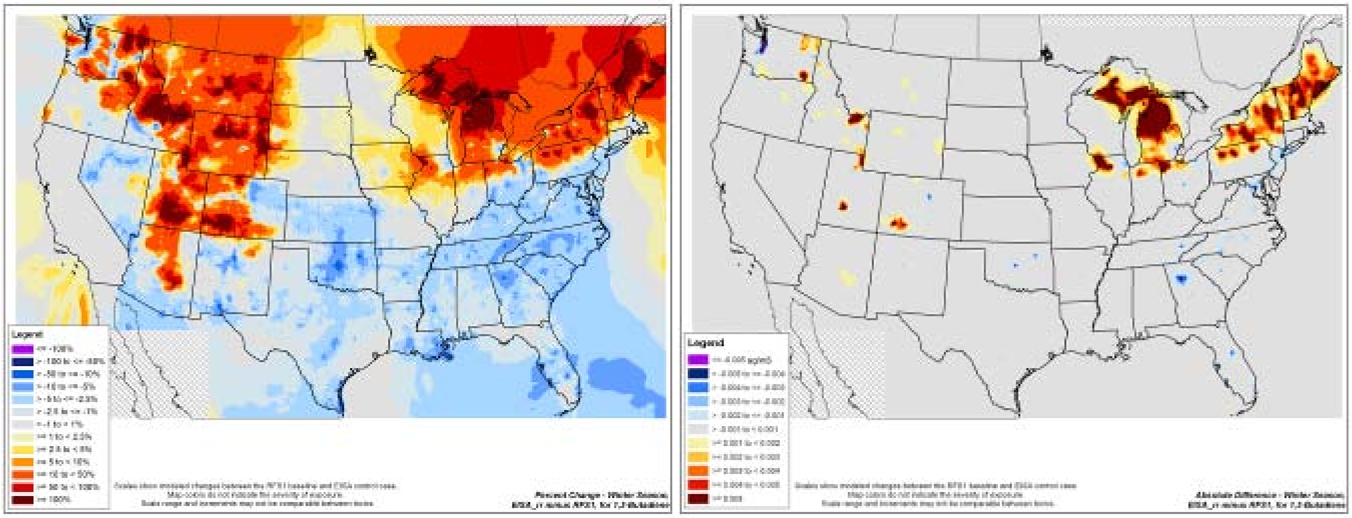


Figure 3A-32. Winter Changes in 1,3-Butadiene Ambient Concentrations Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (µg/m³)

### 3A.2.6 Acrolein

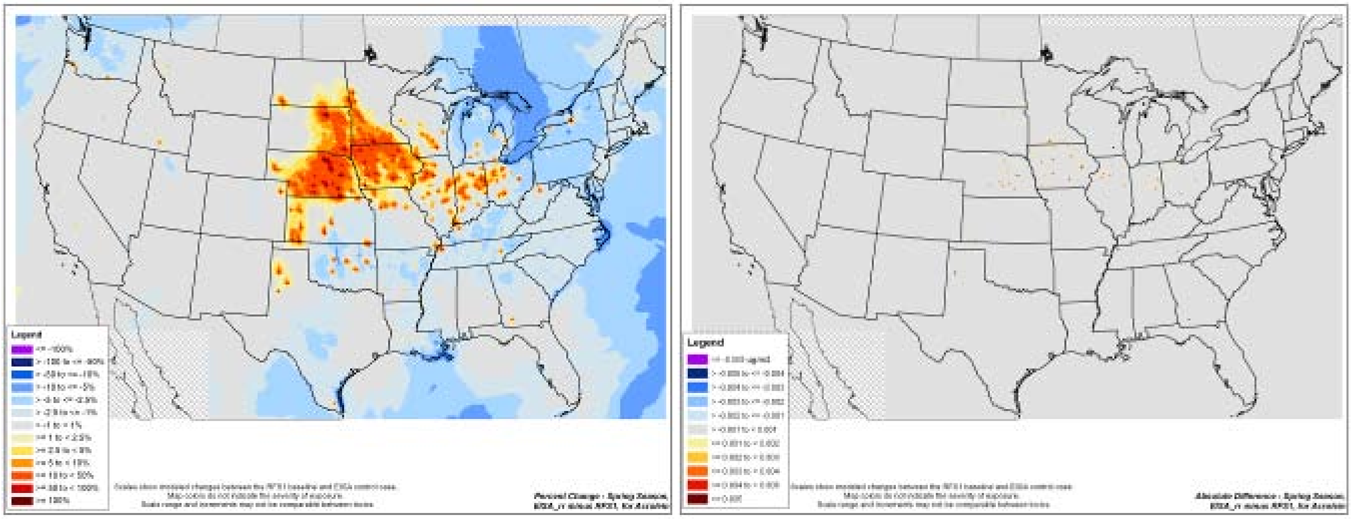


**Figure 3A-33. Spring Changes in Acrolein Ambient Concentrations Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (µg/m³)**

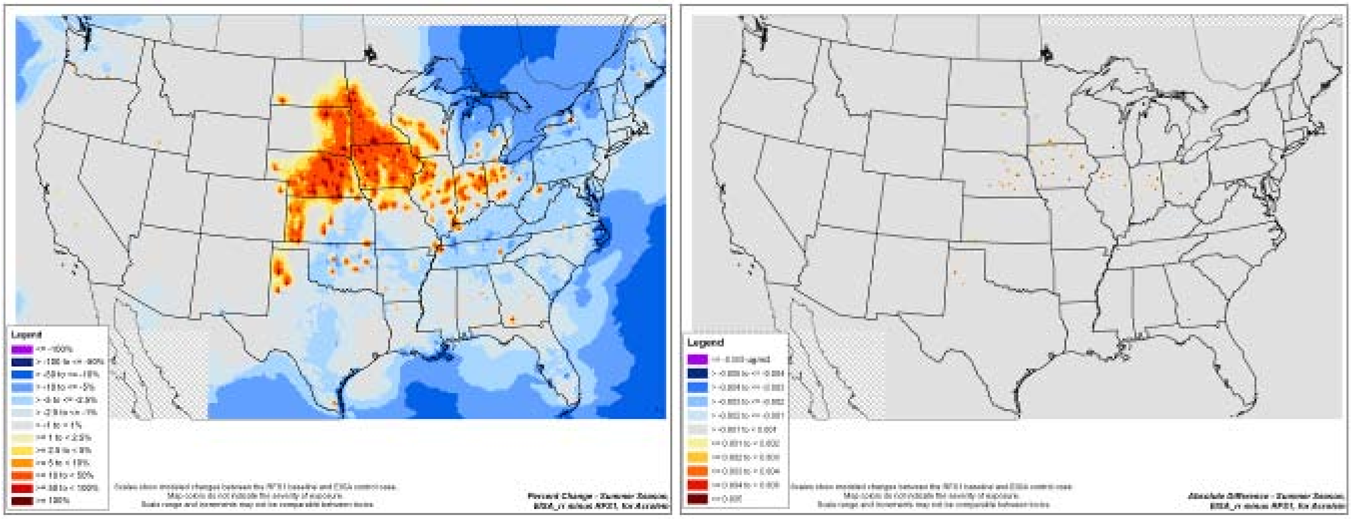


**Figure 3A-34. Summer Changes in Acrolein Ambient Concentrations Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (µg/m³)**

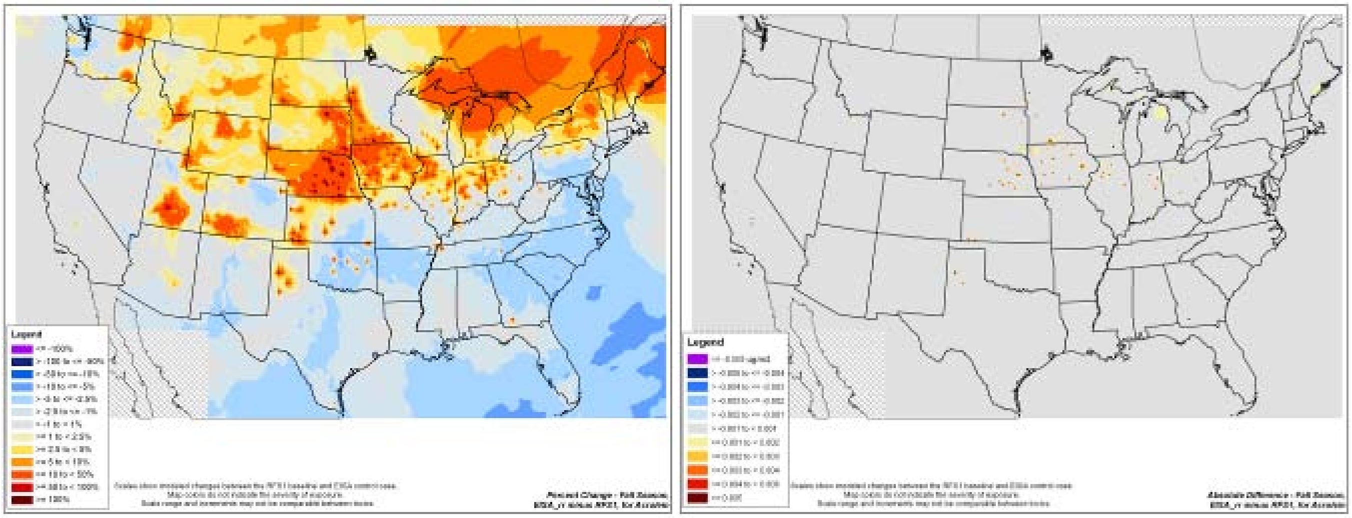


**Figure 3A-35. Fall Changes in Acrolein Ambient Concentrations Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (µg/m³)**

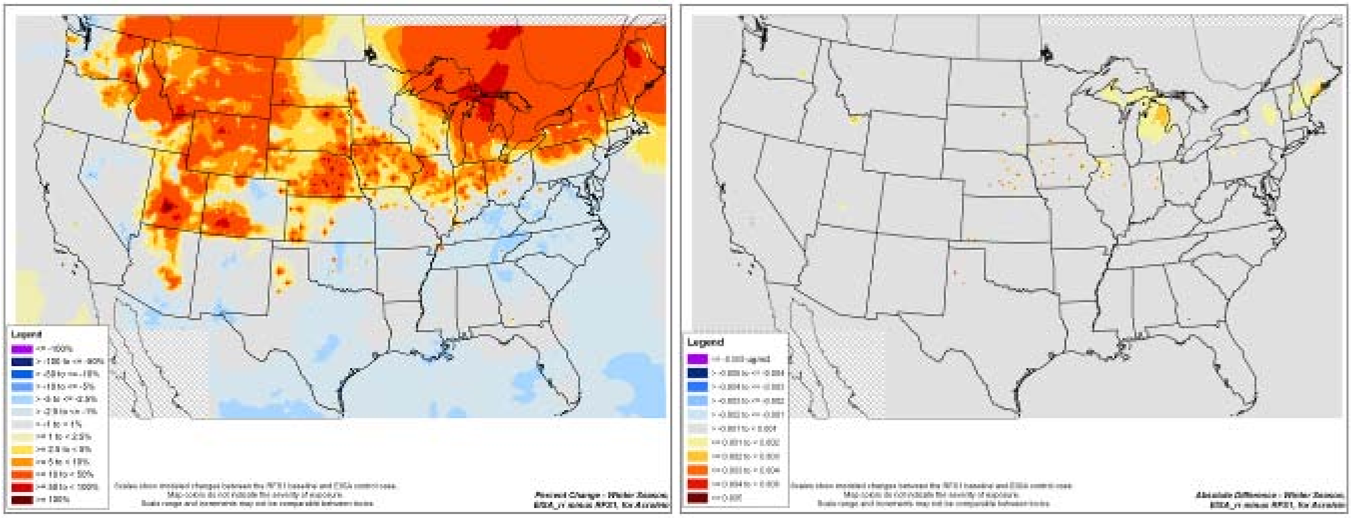


**Figure 3A-36. Winter Changes in Acrolein Ambient Concentrations Between the RFS1 Mandate Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (µg/m³)**

## 3A.3 Seasonal Change Ambient Concentration Maps for Air Toxics using the AEO Reference Case

The following section presents maps of seasonal changes in ambient concentrations of modeled air toxics in 2022 using the AEO 2007 reference case compared to the RFS2 control case.

### 3A.3.1 Acetaldehyde

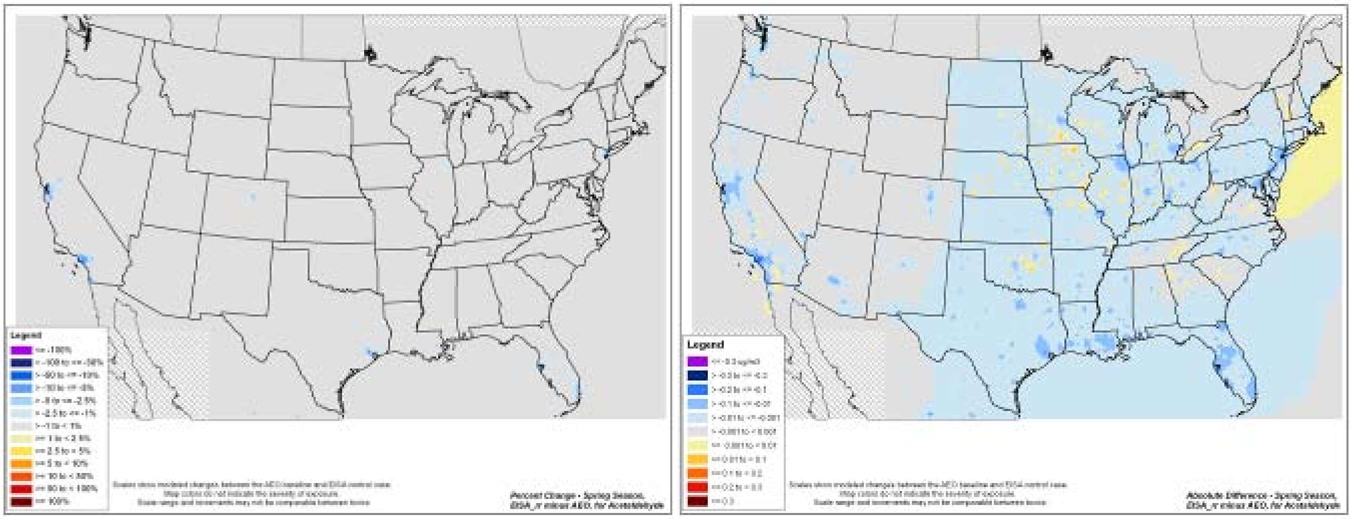


**Figure 3A-37. Spring Changes in Acetaldehyde Ambient Concentrations Between the AEO 2007 Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (μg/m³)**

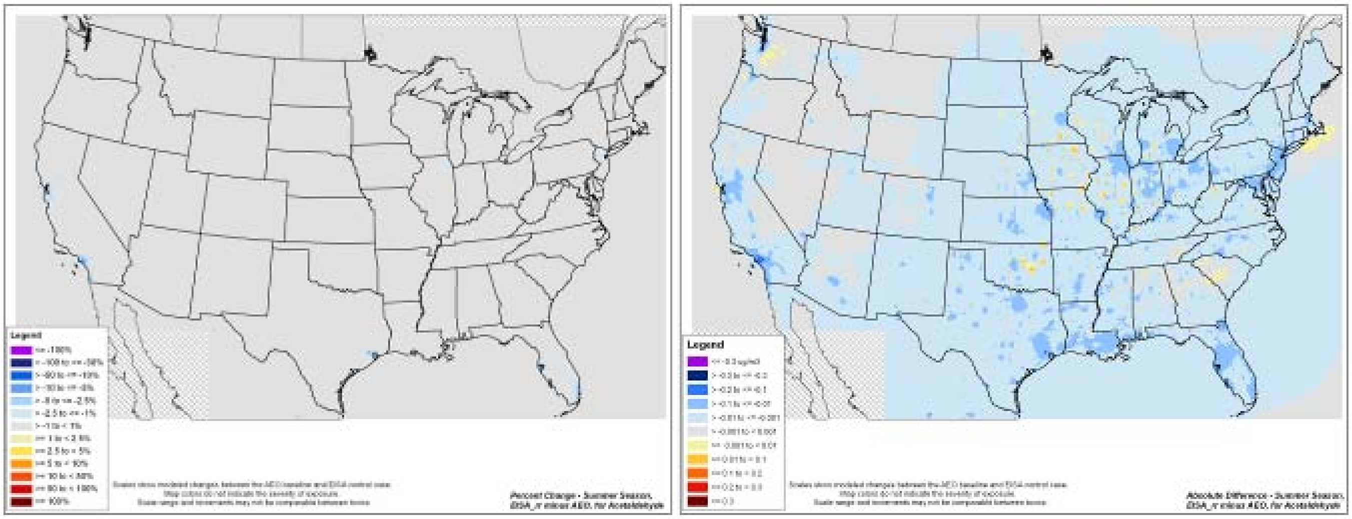


**Figure 3A-38. Summer Changes in Acetaldehyde Ambient Concentrations Between the AEO 2007 Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (μg/m³)**

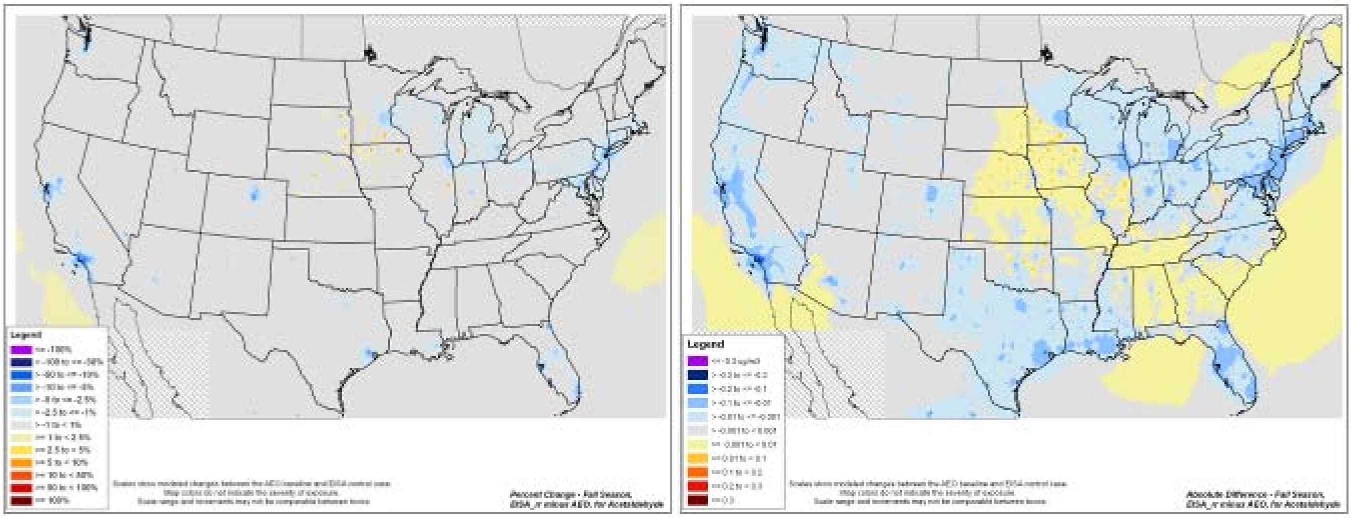


Figure 3A-39. Fall Changes in Acetaldehyde Ambient Concentrations Between the AEO 2007 Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (μg/m³)

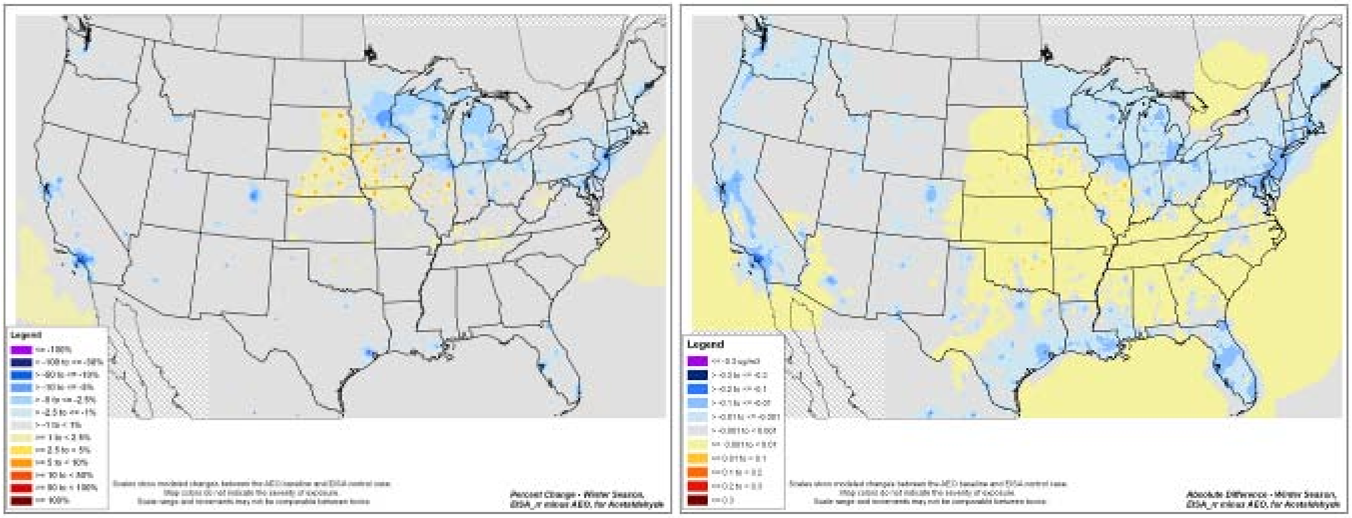


Figure 3A-40. Winter Changes in Acetaldehyde Ambient Concentrations Between the AEO 2007 Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (μg/m³)

### 3A.3.2 Formaldehyde

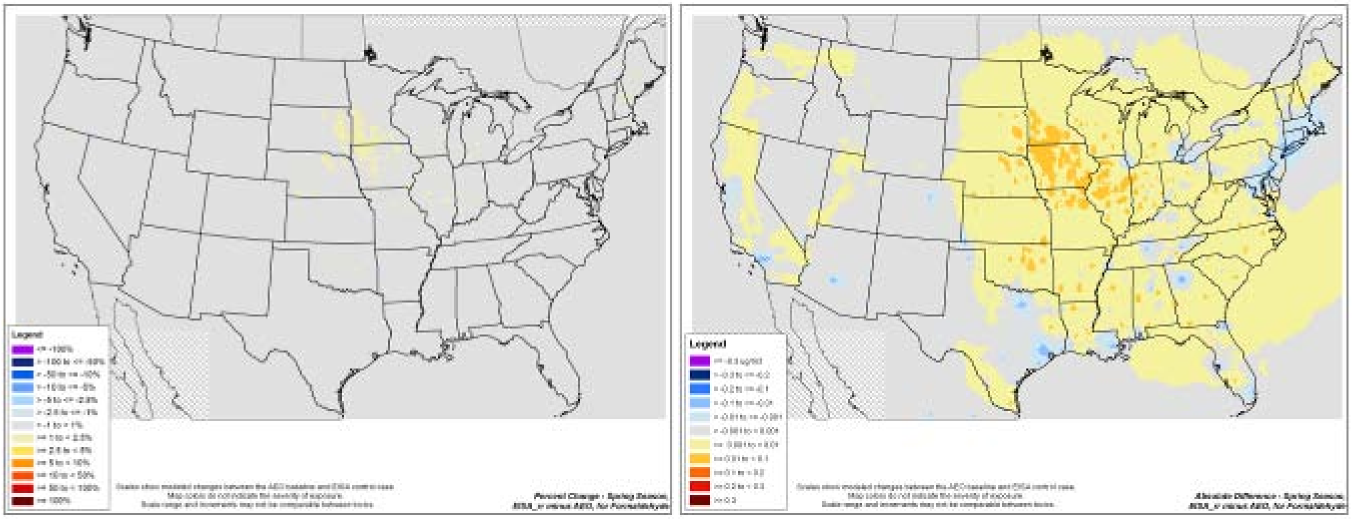


**Figure 3A-41. Spring Changes in Formaldehyde Ambient Concentrations Between the AEO 2007 Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (μg/m³)**

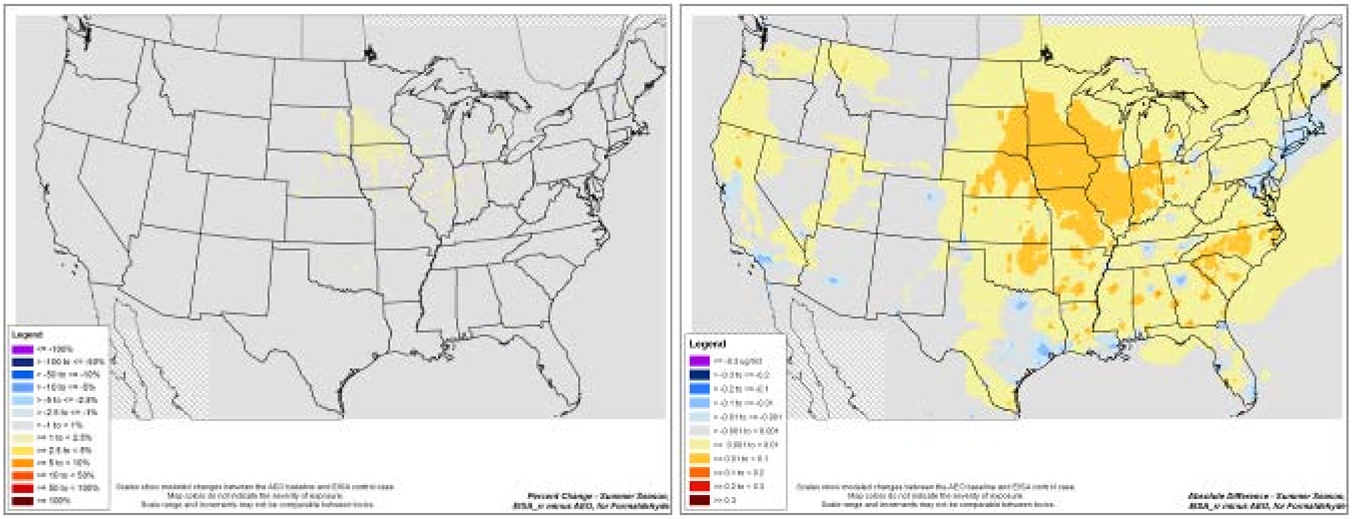


**Figure 3A-42. Summer Changes in Formaldehyde Ambient Concentrations Between the AEO 2007 Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (μg/m³)**

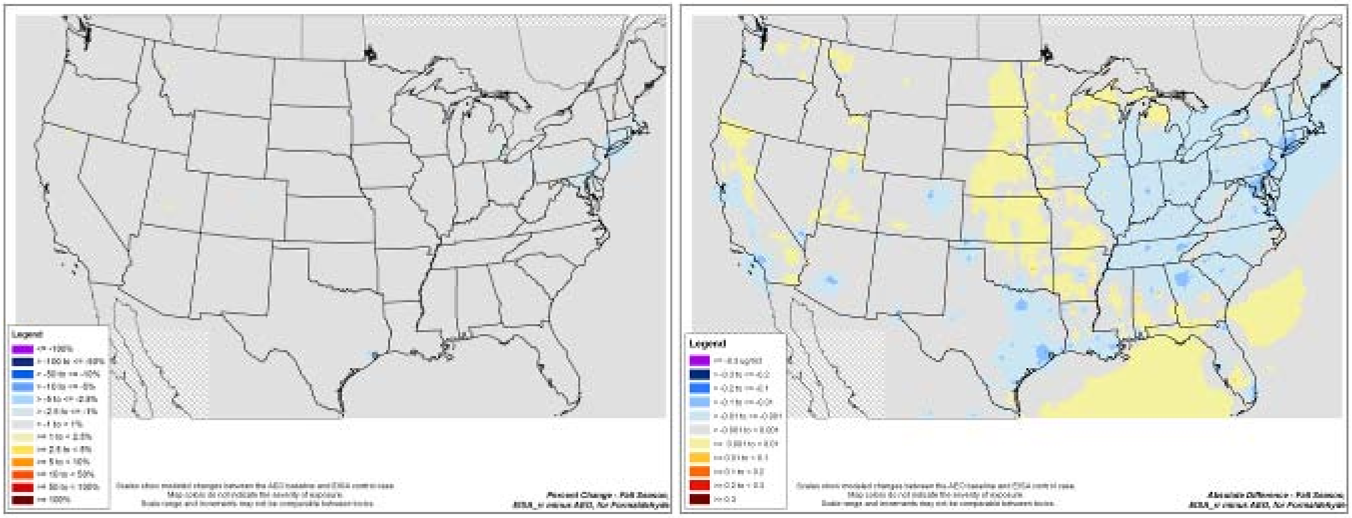


**Figure 3A-43. Fall Changes in Formaldehyde Ambient Concentrations Between the AEO 2007 Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (μg/m³)**

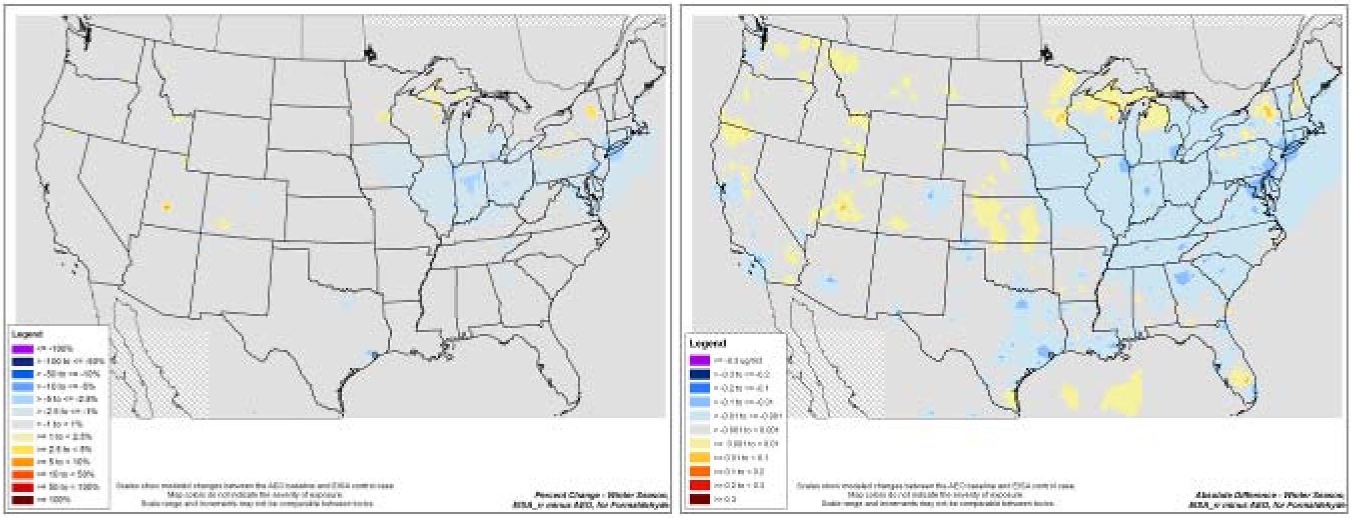


**Figure 3A-44. Winter Changes in Formaldehyde Ambient Concentrations Between the AEO 2007 Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (μg/m³)**

### 3A.3.3 Ethanol

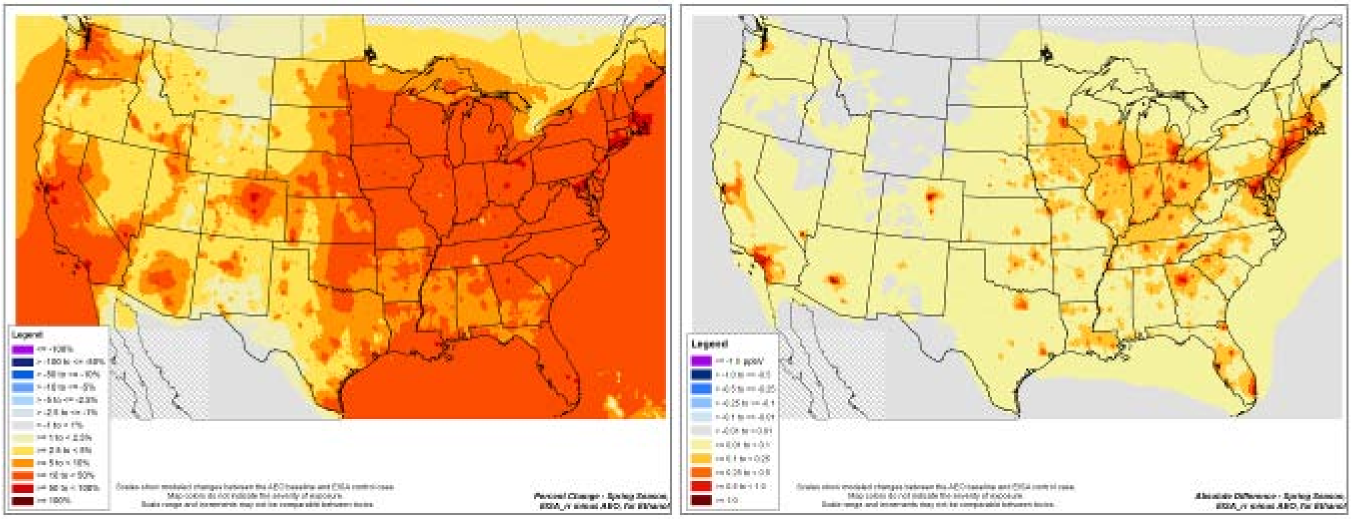


**Figure 3A-45. Spring Changes in Ethanol Ambient Concentrations Between the AEO 2007 Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (μg/m³)**

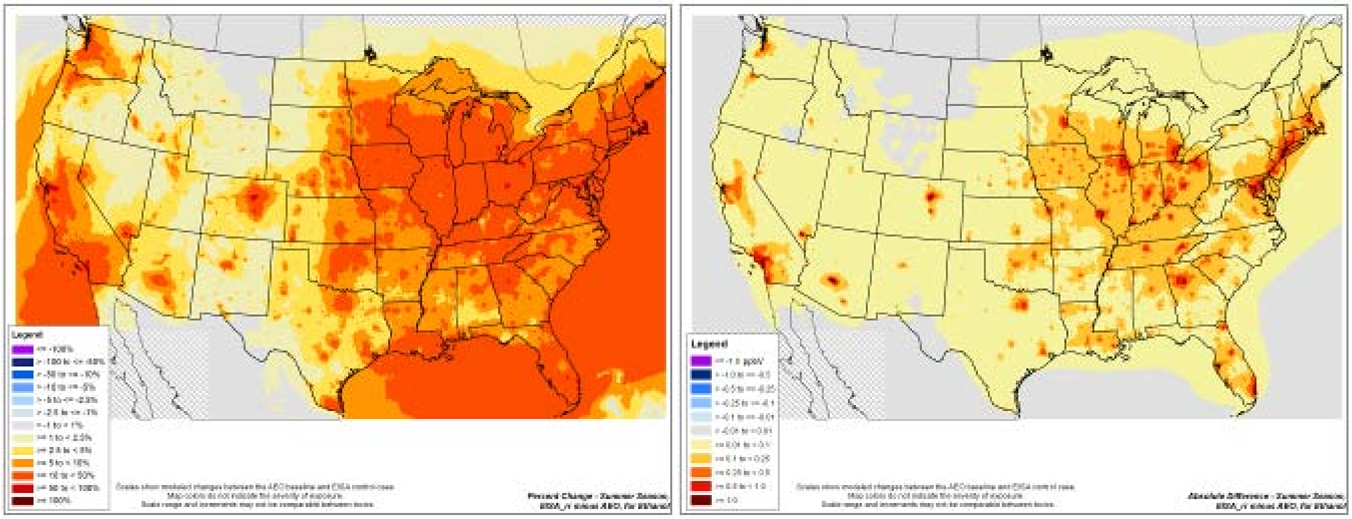


**Figure 3A-46. Summer Changes in Ethanol Ambient Concentrations Between the AEO 2007 Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (μg/m³)**

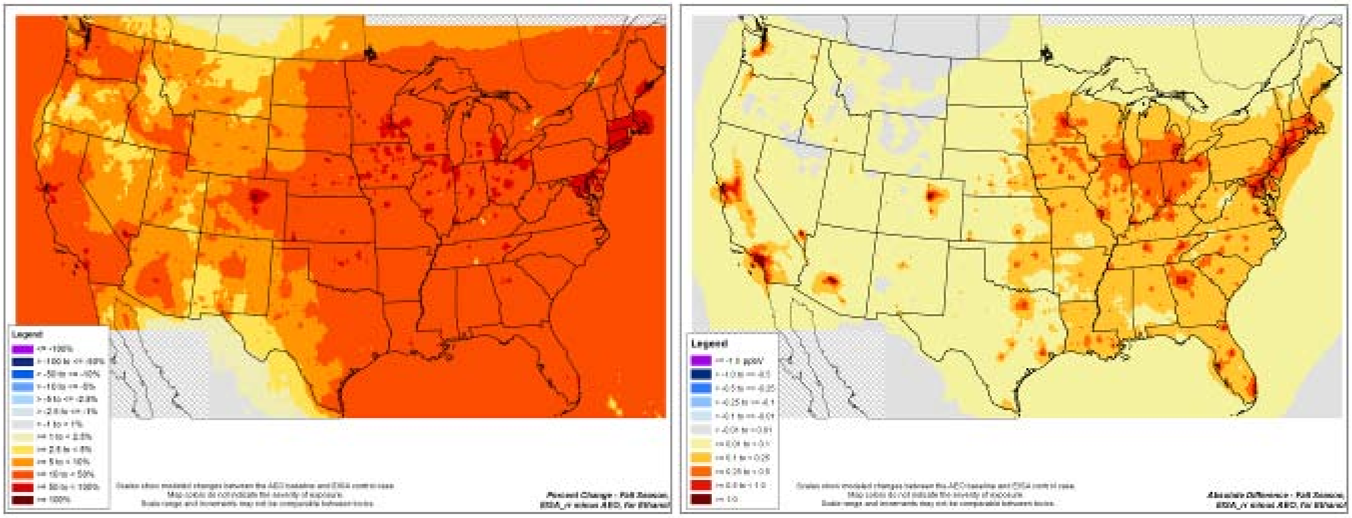


Figure 3A-47. Fall Changes in Ethanol Ambient Concentrations Between the AEO 2007 Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (µg/m³)

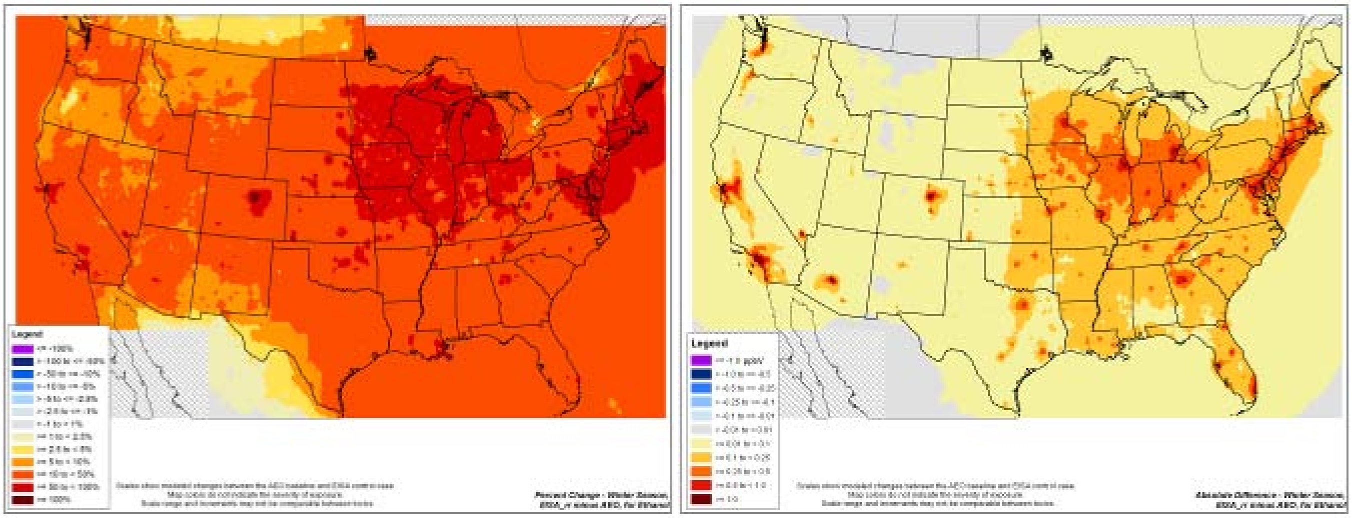


Figure 3A-48. Winter Changes in Ethanol Ambient Concentrations Between the AEO 2007 Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (µg/m³)

### 3A.3.4 Benzene

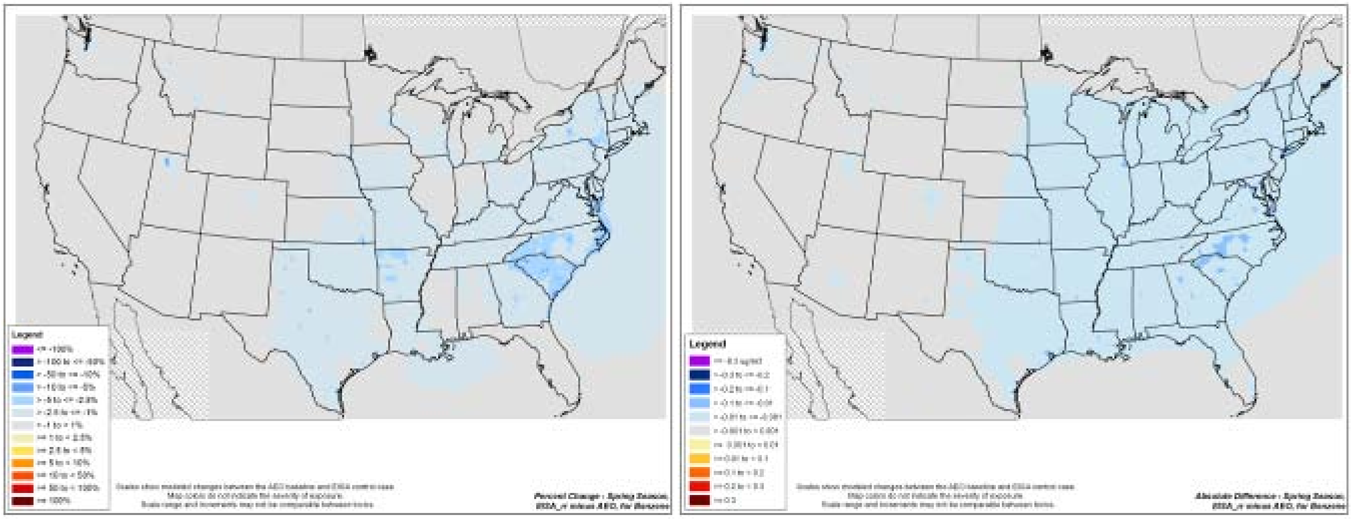


Figure 3A-49. Spring Changes in Benzene Ambient Concentrations Between the AEO 2007 Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (µg/m³)

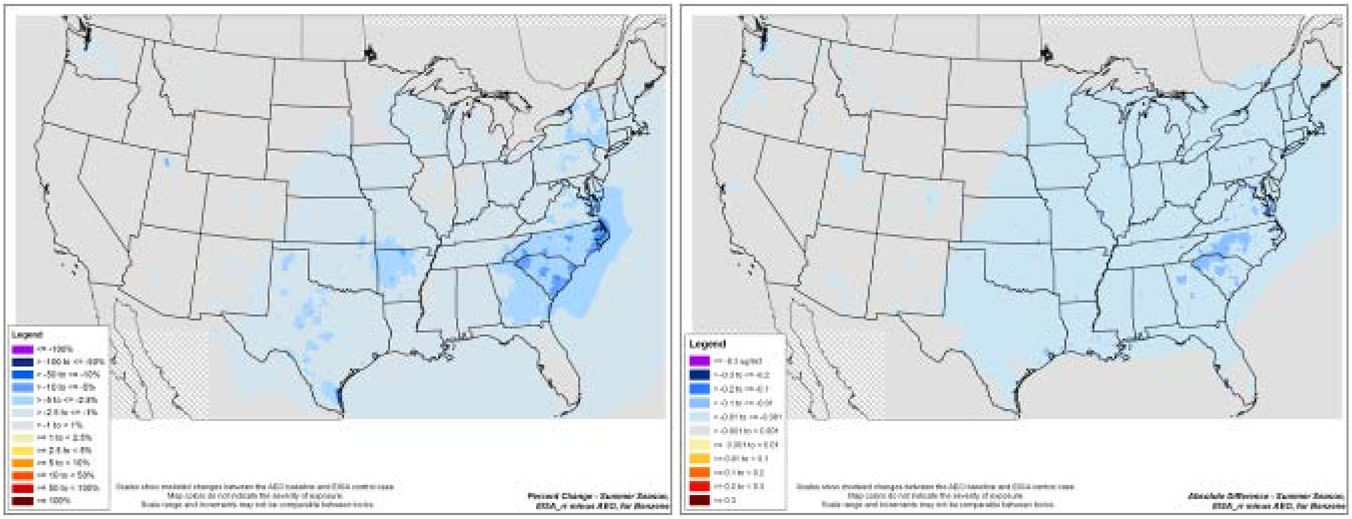


Figure 3A-50. Summer Changes in Benzene Ambient Concentrations Between the AEO 2007 Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (µg/m³)

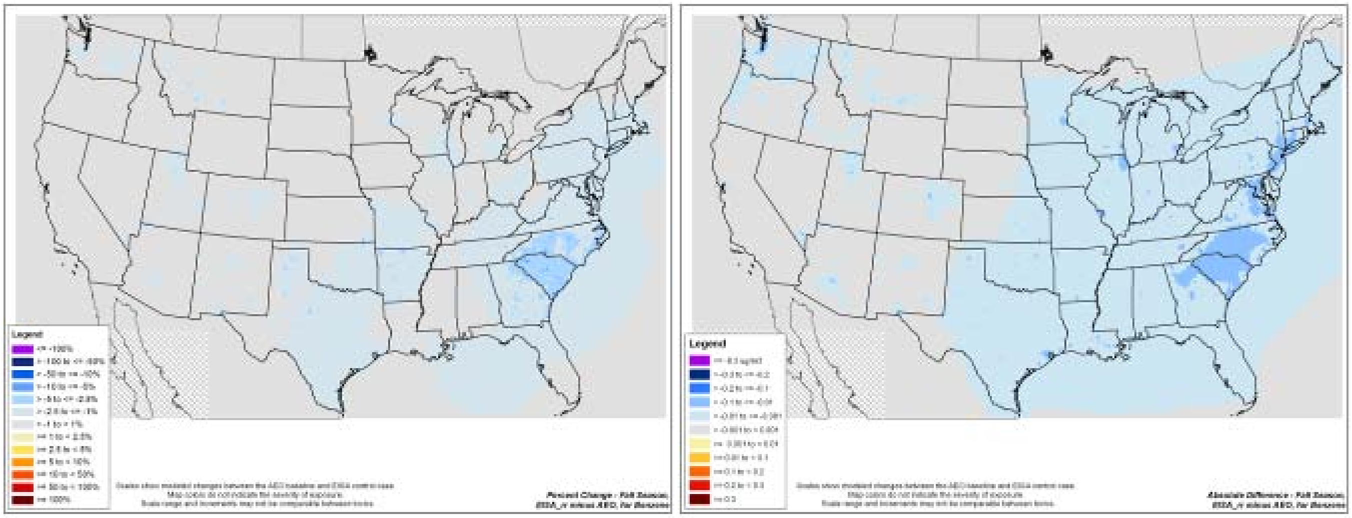


Figure 3A-51. Fall Changes in Benzene Ambient Concentrations Between the AEO 2007 Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (µg/m³)

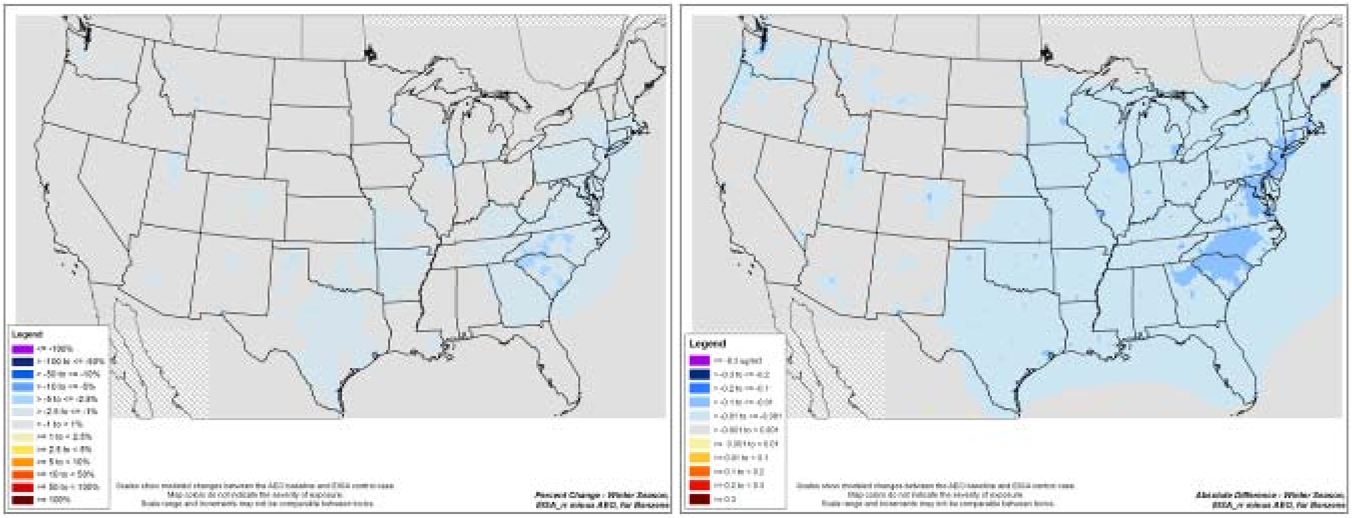


Figure 3A-52. Winter Changes in Benzene Ambient Concentrations Between the AEO 2007 Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (µg/m³)

### 3A.3.5 1,3-Butadiene

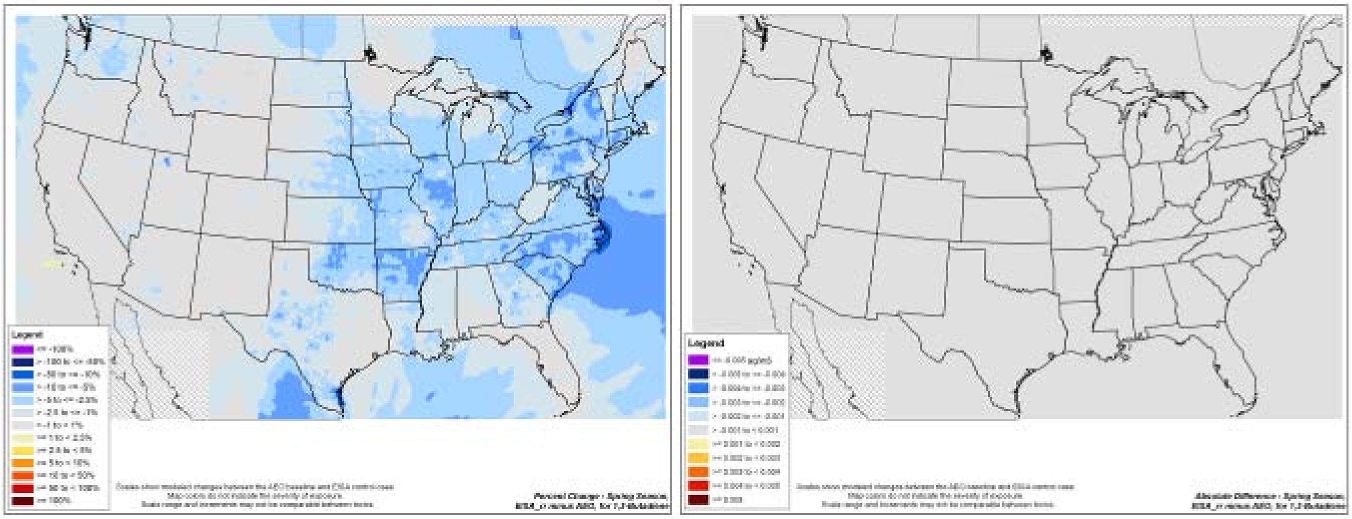


**Figure 3A-53. Spring Changes in 1,3-Butadiene Ambient Concentrations Between the AEO 2007 Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (µg/m³)**

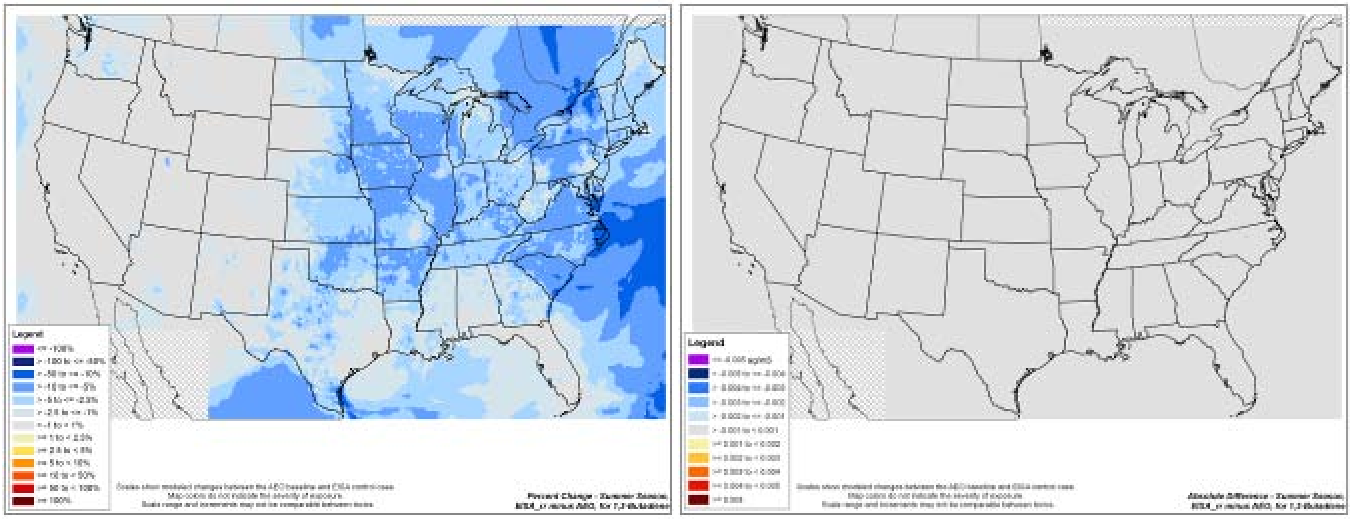


**Figure 3A-54. Summer Changes in 1,3-Butadiene Ambient Concentrations Between the AEO 2007 Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (µg/m³)**

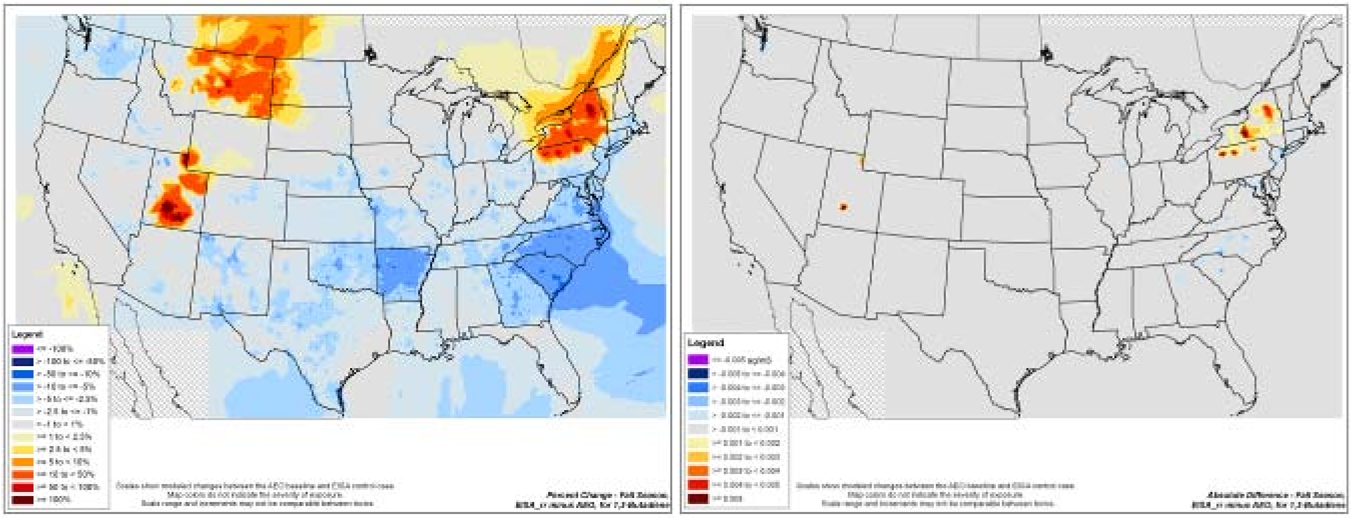


Figure 3A-55. Fall Changes in 1,3-Butadiene Ambient Concentrations Between the AEO 2007 Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (µg/m³)

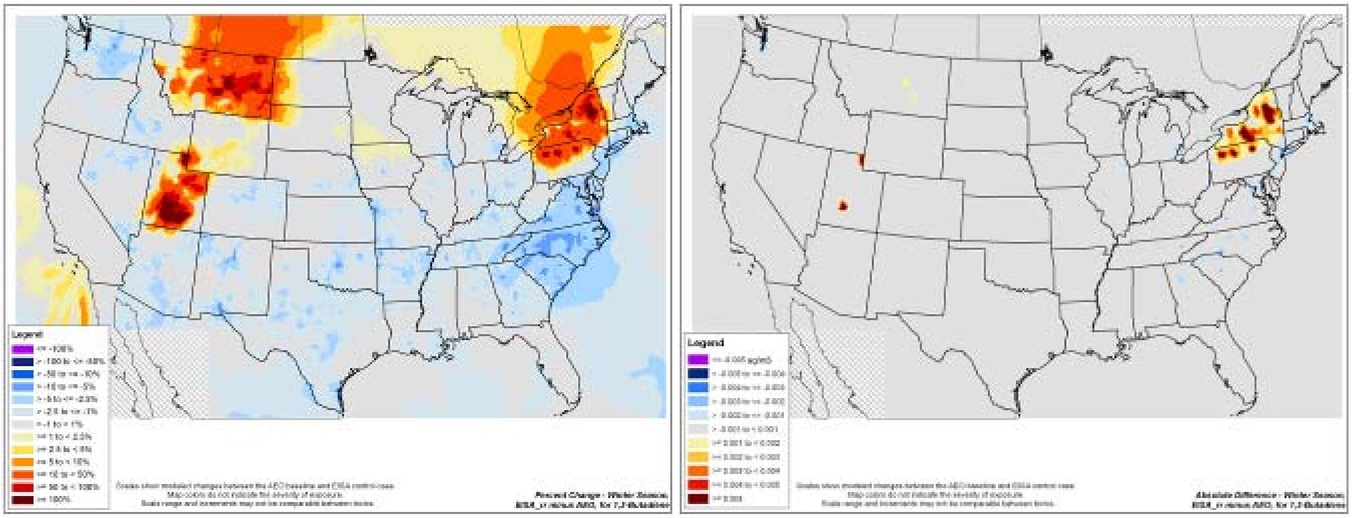


Figure 3A-56. Winter Changes in 1,3-Butadiene Ambient Concentrations Between the AEO 2007 Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (µg/m³)

### 3A.3.6 Acrolein

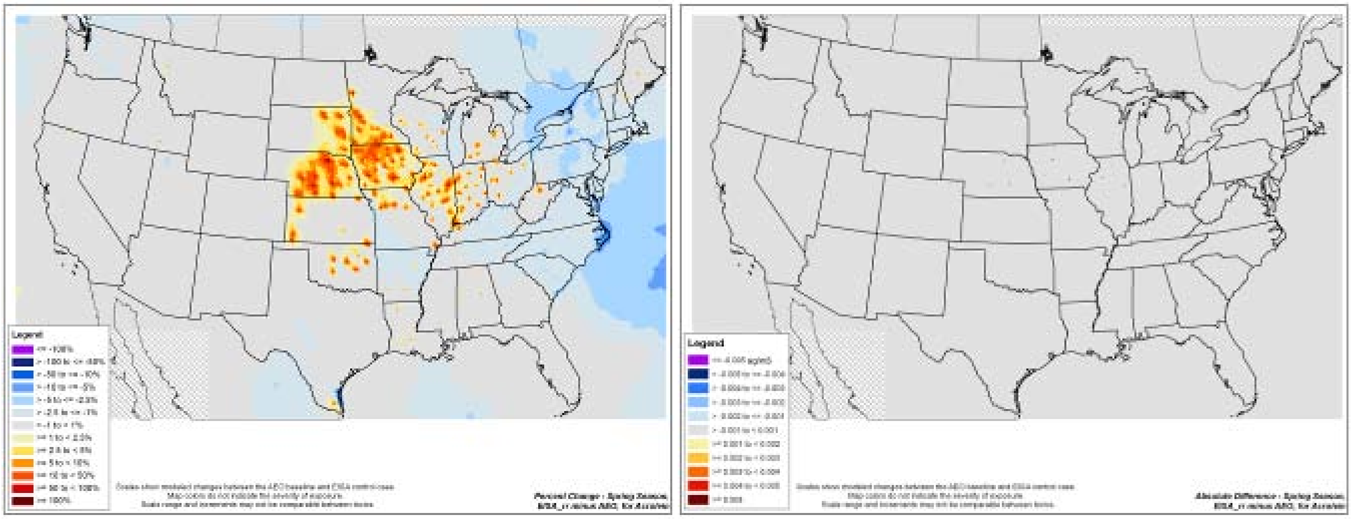


**Figure 3A-57. Spring Changes in Acrolein Ambient Concentrations Between the AEO 2007 Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (μg/m³)**

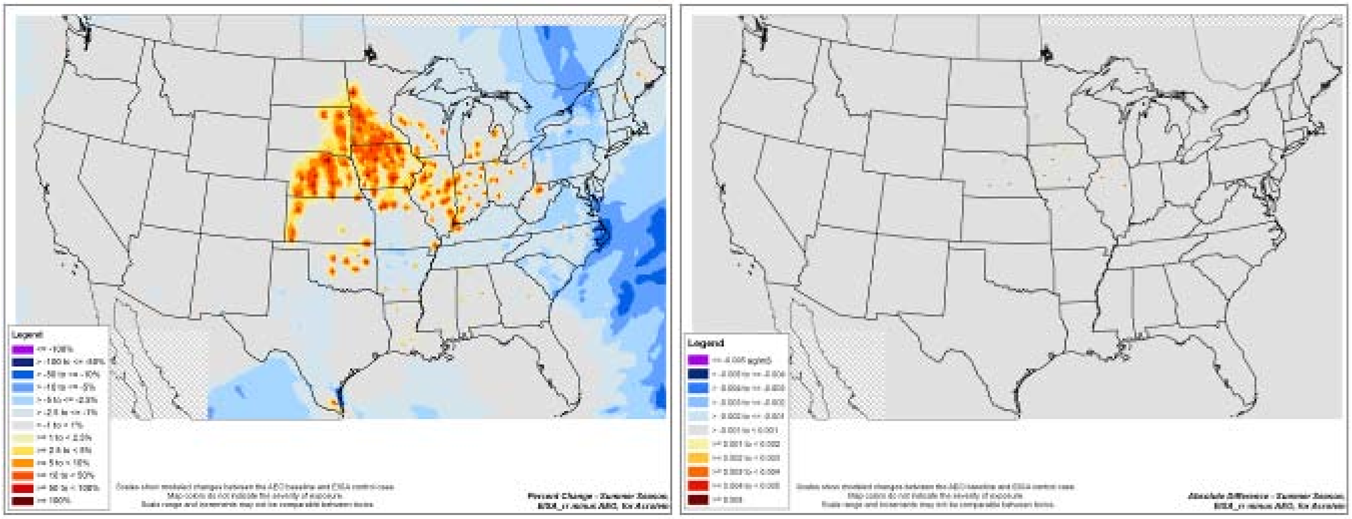


**Figure 3A-58. Summer Changes in Acrolein Ambient Concentrations Between the AEO 2007 Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (μg/m³)**

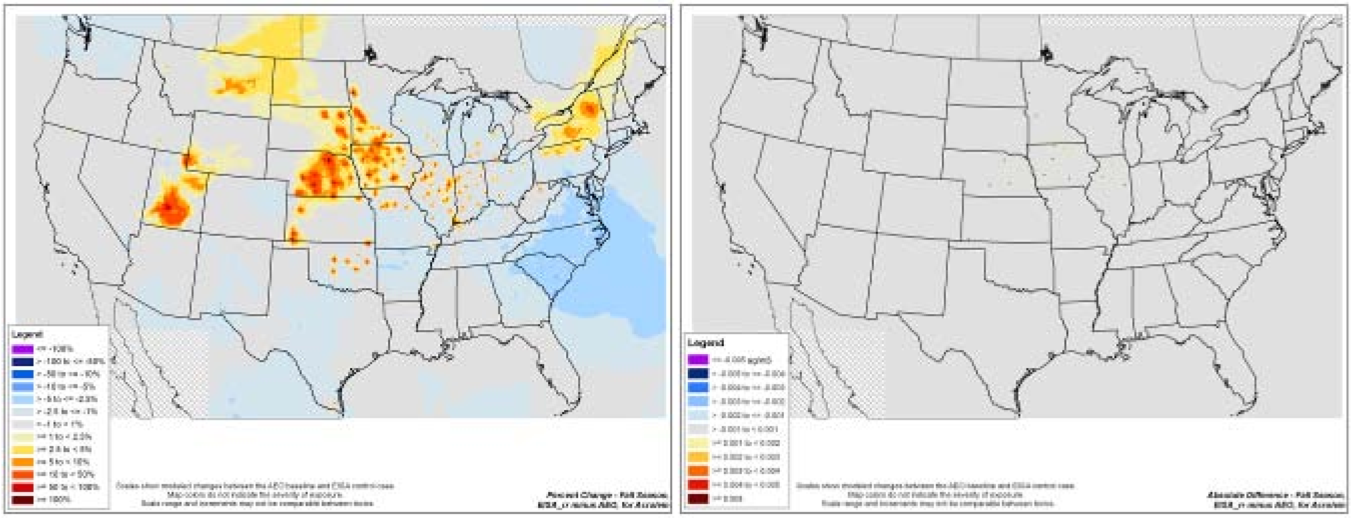


Figure 3A-59. Fall Changes in Acrolein Ambient Concentrations Between the AEO 2007 Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (μg/m³)

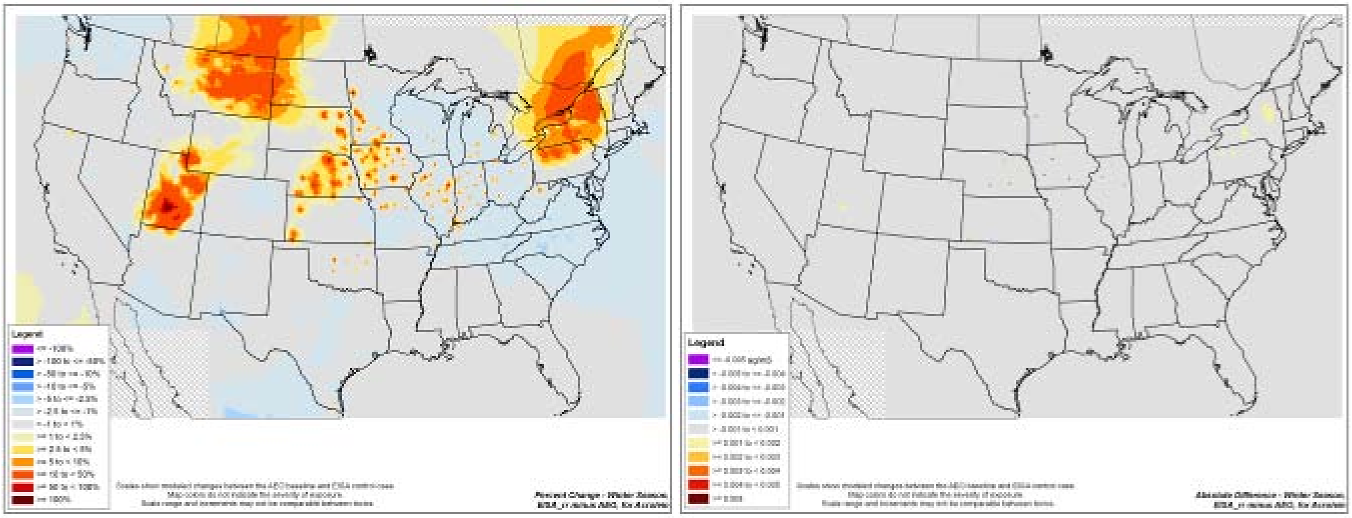


Figure 3A-60. Winter Changes in Acrolein Ambient Concentrations Between the AEO 2007 Reference Case and the RFS2 Control Case in 2022: (left) Percent Changes and (right) Absolute Changes (μg/m³)

## 3A.4 Air Toxics Population Metrics using the AEO Reference Case

The following section presents population metrics for the modeled air toxics in 2022 using the AEO 2007 reference case compared to the RFS2 control case including the estimated aggregated populations above and below reference concentrations for noncancer effects, and population living in areas with increases or decreases in concentrations of various magnitudes.

**Table 3A-1.**
**Populations Exposed to Ambient Concentrations of Air Toxics above and below Reference Concentrations for Noncancer Health Effects in 2022 with RFS2**

| | **CAS No.** | **Population-weighted Concentration (Annual Average in μg/m³)** | | | **National Population above RfC (Annual Average)** | | |
|---|---|---|---|---|---|---|---|
| | | RFS2 | AEO 2007 | Diff. | RFS2 | AEO 2007 | Diff. |
| Acetaldehyde | 75070 | 1.590 | 1.613 | -0.023 | 0 | 0 | 0 |
| Acrolein | 107028 | 0.017 | 0.017 | -0.0001 | 92,452,143 | 94,087,145 | -1,635,002 |
| Benzene | 71432 | 0.520 | 0.527 | -0.007 | 0 | 0 | 0 |
| 1,3-Butadiene | 106990 | 0.022 | 0.023 | -0.208 | 0 | 0 | 0 |
| Ethanol | 64175 | 1.521 | 1.112 | 0.409 | - | - | - |
| Formaldehyde | 50000 | 1.549 | 1.555 | -0.006 | 0 | 0 | 0 |

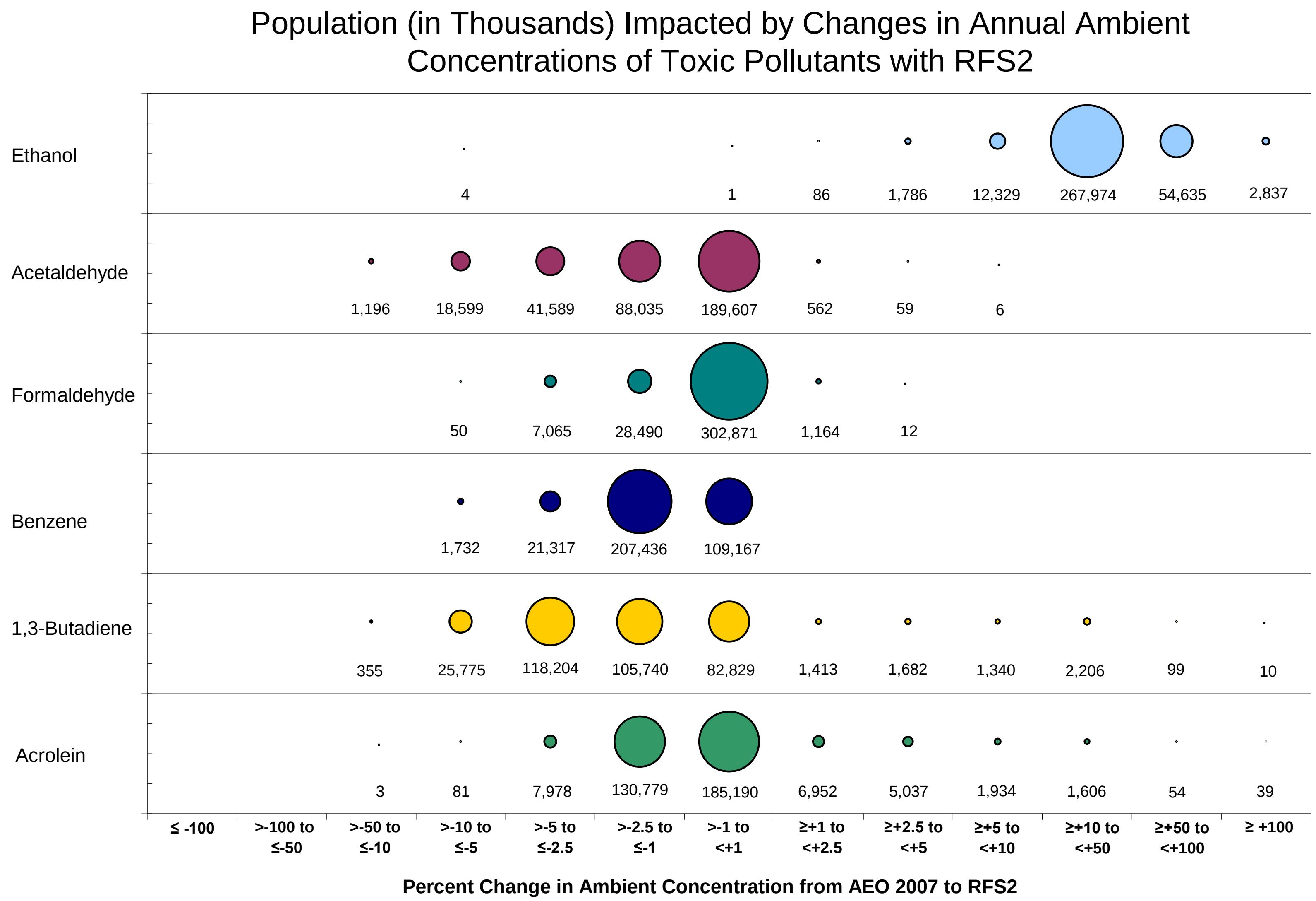


**Figure 3A-61. Number of People Impacted by Changes in Annual Ambient Concentrations or Toxic Pollutants by Percent Change Brackets, AEO 2007 Reference Case Compared to the RFS2 Control Case**

# Chapter 4: Impacts on Cost of Renewable Fuels, Gasoline, and Diesel

## 4.1 Renewable Fuel Production Costs

### 4.1.1 Ethanol Production Costs

#### 4.1.1.1 Corn Ethanol

Corn ethanol costs for our work were estimated using a model developed by USDA that was documented in a peer-reviewed journal paper on cost modeling of the dry-grind corn ethanol process.[1087] The USDA model considers a 40 MMgal/yr corn plant producing ethanol with a primary co-product of distillers dried grains with solubles (DDGS). The ethanol yield used in the model is 2.76 gallons per bushel with 2.0% gasoline denaturant. The model is based on work done in chemical process simulation software to generate equipment sizes, stream flowrates, and material and energy balances. These results can then be put together with feedstock, energy, and equipment cost information in a spreadsheet format to generate a per-gallon cost estimate.

For our primary case scenario, we used corn prices of $3.60/bu in 2022 with corresponding DDGS prices of $124.74/ton (all 2007$). These estimates are taken from agricultural economics modeling work done for this proposal using the Forestry and Agricultural Sector Optimization Model. Energy prices also play a significant role in the cost of ethanol production. For this we relied on the AEO 2009 report for projections of energy costs in 2022 and intermediate years of interest. According to the AEO 2009 updated report the relevant costs are as follows: $7.75 per MMBTU natural gas, $2.57 per MMBTU coal, $30.32 per MMBTU gasoline (~$3.49 per gallon), and $19.31 per MMBTU electricity ($0.066 per kWh). All of these prices are in 2007 dollars.

Using the USDA models and the feedstock and energy prices mentioned above we were able to generate a per gallon cost of ethanol production from a dry mill plant that produces dry DGS, uses natural gas as it's primary fuel source, and utilized no advanced technologies. We did, however, assume that by 2022 the combination of process improvements and more efficient boilers and motors allow the plant described here to produce ethanol with an energy input of 28,660 BTU natural gas per gallon and 2,251 BTU of electricity per gallon. These energy use values are described in more detail in Section 1.5.1.3. The only modification that was made to the USDA model, other than updating the energy and feedstock costs in line with our 2022 projections, was to change the energy demand of the plant to match our projections[PPPPPPPPP]. The projected cost of ethanol production from this modified USDA model was $1.63 per gallon. For this scenario corn feedstock minus DDGS sale credit represents about 54% of the final per-gallon cost, while utilities, facility, chemical and enzymes, and labor comprise about 22%, 13%, 7%, and 4%, respectively. Figure 4.1-1 shows the cost breakdown for production of a gallon of ethanol. Note that this production model does not account for the cost to ship the DDGS. Those costs are external and are expected to increase the price of DDGS the further an end user is located from the plant. While we do not expect this to be the average cost of ethanol production

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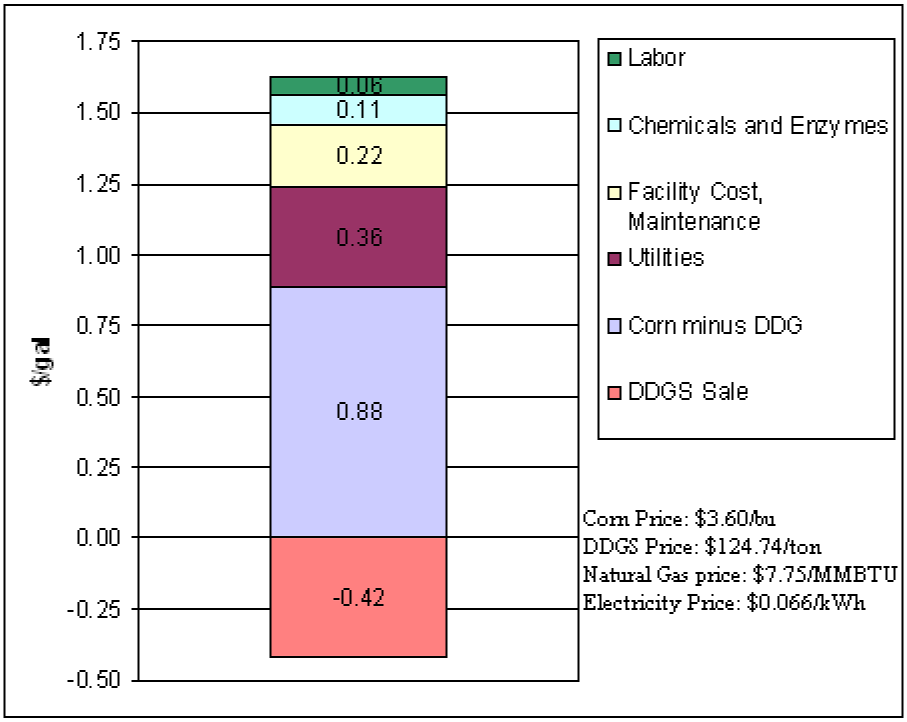
[PPPPPPPPP] An Excel spreadsheet showing a summary of the outputs of this model and the modifications that were made has been placed in the docket (EPA-HQ-OAR-2005-0161- 2726).

in 2022 it serves as a baseline cost to which the cost impacts of different types of fuel used for primary process energy, new technologies, and DGS drying will be applied below.

**Figure 4.1-1.**
**Cost Breakdown of Natural Gas Dry Mill Corn Ethanol Production (2007$).**



The price of energy can vary greatly depending on the source of the energy. We expect, therefore, that the cost of ethanol production would also vary depending on whether the production facility uses natural gas, coal, or biomass as its primary thermal energy source. In order to determine the impact that different fuel sources had on the cost of ethanol production in 2022 we first had to project how much of the corn ethanol industry will use each fuel type in 2022. For these projections we relied on our own current industry characterization as well as projections made by Steffen Mueller of the University of Illinois at Chicago. The resulting mix of primary fuel type used in the corn ethanol industry is shown in Table 4.1-1 below.

**Table 4.1-1.**
**Breakdown of fuel types used in estimating production cost of corn ethanol**

| | **Fuel Type** | | | | **Total by Plant Type** |
|---|---|---|---|---|---|
| **Plant Type** | **Biomass** | **Coal** | **Natural Gas** | **Biogas** | **All Fuels** |
| Coal/Biomass Boiler | 11% | 0% | - | - | 11% |
| Coal/Biomass Boiler + CHP | 10% | 4% | - | - | 14% |
| Natural Gas Boiler | - | - | 49% | 14% | 63% |
| Natural Gas Boiler + CHP | - | - | 12% | - | 12% |
| Total by Fuel Type | 21% | 4% | 61% | 14% | 100% |

To determine per-gallon cost impact of coal, biomass, and biogas as a process energy source we relied on the modeling work done by the USDA. The USDA modeled dry mill corn ethanol plants using both natural gas and coal as a primary energy source. Their models take into account the differences in capital costs that result from the differences in materials handling and boiler types necessary to use gaseous and solid fuels. We assumed that on average, coal and biomass combustion systems would have the same capital cost due to similarities in feed, ash handling, and emission controls; the same argument can be made for use of biogas combustion relative to natural gas combustion (excluding the digesters or other source). Table 4.1-2 shows the impact that different primary fuel sources have on the overall cost per gallon of corn ethanol production. The overall impact of using different fuel types is very small, less than $0.01 per gallon. Thus, a change in process fuel type has very little impact on the projected future cost of corn ethanol.

**Table 4.1-2.**
**Breakdown of cost impacts by fuel type used in estimating production cost of corn ethanol**

| | **Fuel Type** | | | | **Total by Plant Type** |
|---|---|---|---|---|---|
| **Plant Type** | **Biomass** [a] | **Coal** | **Natural Gas** | **Biogas** [b] | **All Fuels** |
| Coal/Biomass Boiler | +$0.009 | +$0.009 | - | - | - |
| Coal/Biomass Boiler + CHP | -$0.021 | -$0.021 | - | - | - |
| Natural Gas Boiler | - | - | baseline | +$0.00 | - |
| Natural Gas Boiler + CHP | - | - | -$0.032 | - | - |
| **Total by Fuel Type** | **-** | **-** | **-** | **-** | **$-0.006** |

Table 4.1-2 shows that for our cost analysis we made the assumption that biomass firing has the same overall cost impact on ethanol production as coal firing. One reason for this is that our analysis of biomass feedstock costs suggests a range of $72 per ton in future years which is comparable to the cost of coal supplied to non-electric-power industries after transportation is included.[1088] Wood and stover biomass has on average approximately 85% of the energy content of coal on a mass basis, varying by type of biomass and coal, again suggesting that they are comparable on an energy per mass basis.[1089] Nevertheless, we still project that biomass will displace some coal in the future. If biomass transportation and storage costs are small it is

plausible that some ethanol producers near biomass sources (such as the Midwest and Southeast) may have a cost incentive to transition from coal to biomass for process heat. In addition, ethanol plant owners may want to improve their greenhouse gas performance to increase capacity.

Similarly, for our cost analysis we made the assumption that biogas combustion for process heat would have the same cost impact on ethanol production as natural gas combustion. Use of biogas is somewhat different from biomass in that it would require some capital investment for on-site anaerobic digesters and related feedstock and gas handling equipment. However, we anticipate the digester feedstock itself would have very low or no cost, thus it is reasonable to assume that the ongoing operating costs besides capital would be considerably less than purchasing natural gas. As with biomass combustion, most plants utilizing biogas would take advantage of situations such as co-location with feedlots or MSW facilities where suitable biomass resources are available.

Another factor that we expect to have a significant impact on the cost of ethanol production in 2022 is the development and adoption of new technologies. There are several new technologies currently available or under development that reduce the energy requirements of ethanol production facilities. These include more efficient boilers, motors and turbines, raw starch hydrolysis, corn fractionation, corn oil extraction, and ethanol membrane dehydration. These technologies, and their impact on the projected average energy usage of an ethanol plant in 2022, are discussed in section 1.5.1.3. In addition to reducing cost by decreasing an ethanol plant's energy demand, two of these technologies, corn fractionation and corn oil extraction, produce new co-product streams that also have an impact on the cost of ethanol production. We have adjusted the USDA cost model to reflect the impact that reduced energy usage of ethanol plants in 2022 and new co-products have on the average cost of ethanol production[QQQQQQQQQ]. The impact of these technologies is outlined in Tables 4.1-3 and 4.1-4 below.

**Table 4.1-3.**
**New Technology Impacts on Corn Ethanol Cost**

| | Capital Cost (40MMGY) | Capital Charge (per gallon) | Operating cost change | New co-product profit | Additional Profit |
|---|---|---|---|---|---|
| More Efficient Boilers, etc. | None (included in baseline) | N/A | N/A | N/A | $0.00 |
| Raw Starch Hydrolysis | $0 | $0.00 | -$0.066 | N/A | $0.066 |
| Corn Fractionation | $14,000,000 | $0.016 | -$0.003 | $0.106 | $0.093 |
| Corn Oil Extraction | $5,100,000 | $0.019 | -$0.037 | $0.060 | $0.079 |
| Membrane Separation | $1,500,000 | $0.006 | -$0.070 | N/A | $0.064 |

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[QQQQQQQQQ] As an example, the spreadsheet with adjusted values for corn oil extraction has been placed in the docket (EPA-HQ-OAR-2005-0161-2727).

### Table 4.1-4.
### Breakdown of cost impacts by technology for estimating production cost of corn ethanol

| Technology | Percent of Plants Adopting Technology | Cost Impact (Change from Baseline) | Weighted Cost Impact |
|---|---|---|---|
| More Efficient Boilers/Motors/Turbines | 100% | Included in Baseline | $0.00 |
| Raw Starch Hydrolysis | 22% | -$0.066 | -$0.015 |
| Corn Fractionation | 20% | -$0.093 | -$0.019 |
| Corn Oil Extraction | 70% | -$0.079 | -$0.055 |
| Membrane Separation | 5% | -$0.064 | -$0.003 |
| Total | N/A | N/A | -$0.092 |

Whether or not the distillers grains and solubles (DGS) are dried also has an impact on the cost of ethanol production. Drying the DGS is an energy intensive process and results in a significant increase energy usages as well as cost. The advantages of dry DGS are reduced transportation costs and a product that is less susceptible to spoilage, and can therefore be sold to a much wider market. If the DGS can be sold wet, the cost of ethanol production can be reduced by $0.083 per gallon. A 2007 survey of ethanol producers indicated that 37% of DGS were being sold wet. We anticipate that this percentage of wet DGS will remain constant in 2022. The net cost impact of selling 37% of the DGS wet is an average cost reduction of $0.031 per gallon.

The effect of plant scaling on production cost can be estimated by applying an engineering scaling factor to all plant equipment. In past rulemakings involving modifications to refineries we have used a material scaling factor of 0.65. This factor is applied as an exponent to the ratio of the new size to the original size, the result of which is then multiplied by the original capital cost. The fact that this figure is less than 1.0 reflects the per-unit or per-gallon savings that is often realized when processes are scaled up. However, there is information suggesting that a general factor may be considerably higher for ethanol plants. A factor of 0.84 was put forth in a recent publication on dry mill ethanol production.[1090] Using this larger factor, we find that the change in per-gallon production cost due to economies of scale is very small over the range of typical plant sizes, on the order of $0.02 between 40 and 100 MMgal/yr. Thus, in computing production costs for this rulemaking we chose to ignore effects of any changes average plant size. A recent study has also indicated that the co-location of corn and cellulosic ethanol plants may result in reductions of the cost of production for both the corn and cellulosic ethanol[1091]. We have not been able to incorporate these findings into our evaluation due to time constraints; however we do not expect that they would have a large impact on the overall cost of corn ethanol production.

In order to generate a cost estimate for the production of corn ethanol in the year 2022 the cost impact of each of these factors, primary fuel type, advanced technologies, and DGS drying, were applied to the baseline cost produced by the USDA model. When each of these cost reduction have been applied to the baseline cost, the result is a projected cost of production for corn ethanol of $1.50 per gallon in 2022. As with the energy and input costs, this production cost is also in 2007 dollars. We believe this number is an accurate projection of the cost of ethanol in 2022 based on the best available information. For a summary of the cost analysis, including the baseline cost and all the adjustments, see Table 4.1-5 below.

**Table 4.1-5.**
**Average Ethanol Cost of Production in 2022**

| | |
|---|---|
| Baseline Cost of Production (Natural Gas, no new technologies, 100% dry DGS) | $1.627/gal |
| Fuel Type Cost Impact | -$0.006/gal |
| New Technology Cost Impact | -$0.092/gal |
| DGS Drying Cost Impact | -$0.031/gal |
| Average Cost of Ethanol Production (2022) | $1.499/gal |

### 4.1.1.2 Cellulosic Ethanol

#### 4.1.1.2.1 Feedstock Costs

In order to allow for an accurate estimate of the cost of production for cellulosic biofuels in 2022 we must first determine the cost of the cellulosic feedstocks. We relied on the Forest and Agriculture Sector Optimization Model (FASOM) to project the roadside cost of agricultural residues, energy crops, and wood residues for 2022. For more details on the FASOM model see Chapter 5 of the RIA. FASOM does not model MSW costs. We therefore relied on conversations with companies who intend to use MSW as a renewable fuel feedstock, as well as our own analysis of the necessary steps required to acquire appropriate feedstock streams from MSW to help inform our feedstock cost estimates. In order to validate the reasonableness of the FASOM cost estimates we also conducted an internal assessment of the potential agricultural residue, energy crop, wood residue, and MSW feedstock systems. The description of this analysis is discussed in Section 4.1.1.2.2.

To each of these roadside costs we added the cost of transportation and secondary storage where appropriate using a tool we developed for this purpose. The framework of this tool is discussed in Section 1.3.3 and a more detailed discussion of the assumptions and equations used in this tool can be found below. Table 4.1-6 shows a summary of the individual roadside costs for each of the feedstock sources, as well as average costs for storage and transport and grinding of the materials. A weighted average cost, based on the percentage of the overall feedstock supply each of the categories is expected to represent according to the FASOM model, is also given.

**Table 4.1-6.**
**Summary of Cellulosic Feedstock Costs**

<table>
<tr><th>Ag Residue</th><th>Switchgrass</th><th>Forest Residue</th><th>MSW</th></tr>
<tr><td>36% of Total Feedstock</td><td>49% of total Feedstock</td><td>1% of Total Feedstock</td><td>15% of Total Feedstock</td></tr>
<tr><td>Mowing, Raking, Baling, Hauling, Nutrients and Farmer Payment<br>$34.49/ton</td><td>Land Rent, Mowing, Raking, Baling, Hauling, Nutrients and Farmer Payment<br>$40.85/ton</td><td>Harvesting, Hauling to Forest Edge,<br>$20.79/ton</td><td>Sorting, Contaminant Removal, Tipping Fees Avoided<br>$15/ton</td></tr>
<tr><td colspan="4">Hauling to Secondary Storage, Secondary Storage, Hauling to Plant<br>$21.53/ton (average)</td></tr>
<tr><td colspan="4">Grinding<br>$11/ton</td></tr>
<tr><td colspan="4">Total<br>$67.42/ton</td></tr>
</table>

*Crop Residue Costs*

The FASOM agricultural econometric model described in Chapter 5 estimated the roadside price for corn stover, which we used to be representative of all agricultural residues. The FASOM model accounted for harvesting, shredding, raking, baling and hauling the corn stover to the farm edge, and replenishing the soil with nutrients. It predicts a roadside price of $34.49 per dry ton in 2022 for corn residue. In order to validate FASOM's cost estimate we also performed an analysis of a possible agricultural residue harvest system. We based our analysis on a Purdue University study of the logistics of corn stover storage and transportation. Our analysis, described in Section 4.1.1.2.2, predicts a roadside cost for corn stover ranging from $44.97 to $46.20 per dry ton, depending on the size of the farms from which the stover is harvested. The FASOM cost is approximately $10 per ton lower than the price calculated in our analysis. While this is a significant price difference it is in the same vicinity as the FASOM estimate, and it is not unreasonable to expect that advances in technology and changes in harvesting practice for corn stover and other agricultural residues will significantly reduce the cost for these feedstocks. For all of the biofuel production cost analysis work, the FASOM price was used as the projected price of agricultural residue. To this roadside cost was added the cost of transportation and secondary storage as calculated by the tool discussed in Section 1.3. A detailed description of our analysis of a likely agricultural residue harvest system using existing machinery can be found below.

*Energy Crops*

The FASOM model predicts a roadside cost for switchgrass and similar energy crops of $40.85 per dry ton in 2022. While this costs is higher than the cost of agricultural residues the delivered cost of energy crops is expected to be slightly lower because of the lower transportation and secondary storage costs associated with the higher production density of energy crops. The $40.85 per dry ton roadside cost has been used in our cost analysis of biofuel production, with appropriate transportation and storage costs added using the tool described in Section 1.3. See Table 4.1-6 for a summary of the expected delivered costs of various feedstocks.

*Wood Residue*

The FASOM model estimates costs for two different types of wood residues, hardwood logging residue ($21.16 per dry ton) and softwood logging residue ($18.37 per dry ton). We decided to use $19.77 per dry ton, an average of these two prices, as the roadside cost of wood residue for our analysis of biofuel production costs. Despite the low roadside cost of wood residues, FASOM predicts that few biofuels production facilities (less than 1%) will use wood residues. We believe that the reason for this is that the high transportation costs for wood residue in the FASOM model cause the delivered cost of wood residue to be relatively high. The FASOM model allowed biofuel producers to use only one type of feedstock (wood residue, agricultural residue, energy crops, or MSW). Therefore, in order for a facility to use wood residues, the entire feedstock supply must come from wood residues. Logging operations are less likely to be concentrated in a small area than other potential feedstock supply systems such as agricultural residues or energy crops. The result is that in order to supply a 100 million gallon per year biofuel production plant (the size specified in the FASOM model) with sufficient feedstock from wood residues the residues must be transported long distances. In most cases these high transportation costs outweighed the low roadside costs despite the fact that no secondary storage will be required for wood residues. If this assumption were relaxed and the FASOM model allowed biofuel production facilities to use locally available wood residues in combination with other feedstocks such as agricultural residues, energy crops, or MSW, we believe that much more wood residues would be selected for biofuel production. At this point, however, it is not clear whether biofuel production facilities would require uniform feedstock or be able to process a diverse feedstock stream. This uncertainty was one of the factors in our decision to use the FASOM estimates for our cost analysis work.

*Municipal Solid Waste*

Unlike the other three sources of cellulosic feedstock, the FASOM model does not predict a roadside cost for MSW. We therefore relied on our own analysis, together with input from the Office of Solid Waste and conversations with companies who intend to use MSW as a feedstock for producing biofuels. One of the biggest costs associated with using MSW as a biofuel feedstock is the cost to sort the waste material. Some materials, such as metals and contaminated materials, must be removed so that they do not interfere with the biofuel production process. Other materials, such as paper or plastics, may also be separated due to their value as recovered materials or in order to increase the renewability content of the resulting fuel.

The Office of Solid Waste has estimated that sorting costs will likely be $20 - $30 per ton. In addition to sorting costs, the biofuel producer would also have to pay for the transportation and disposal of unusable material. These costs may be relatively high due to the nature of this contaminated material. Offsetting these costs would be tipping fees received by the biofuel producer, which we estimate would be in the $30 per ton range.

In addition to our own analyses presented in Section 4.1.1.2.2, we also contacted companies that intend to use MSW as a feedstock for biofuel production. In confidential conversations these companies indicated that they believed that MSW would be available, at least initially, at close to zero net cost, after accounting for the receipt of tipping fees and the sale of recoverable materials. One company told us that whether the MSW was sorted or unsorted was not expected to make much of a difference from a cost perspective, as they expected that the higher tipping fees received for unsorted MSW and the money received from the sale of the recovered materials would pay for the cost of sorting. We believe that while these costs may be accurate, they are likely only representative of the cheapest and most readily available sources of MSW. It is likely that as more biofuel producers seek to use MSW as a feedstock, the cost of this feedstock source will increase. Competition from waste to energy companies may be another driver for the cost increase of MSW. Taking all this into account, we have conservatively estimated that the average cost of MSW will be $15 per dry ton in 2022. While this is an admittedly conservative estimate, MSW remains the cheapest source of feedstock for the production of biofuels. More details of our cost assessment for MSW can be found below.

#### 4.1.1.2.2 EPA Internal Assessment of Potential Roadside Cellulosic Feedstock Costs

While the FASOM model provides an estimate for the roadside costs of agricultural residue, energy crops, and wood residue, we were also interested in performing our own internal assessment of the potential roadside cost of these feedstocks. This assessment served as a second estimate for the costs of these feedstocks, and allowed us to verify the costs generated by FASOM. They also allowed us to have a better understanding of the costs of each of the steps in the harvest process. In each of these cases we found that our own assessments matched reasonably well with the roadside costs reported by FASOM. Our internal assessment of the roadside costs of crop residue, energy crops, wood residue, and MSW is shown in detail in the following sections.

##### *Crop Residue*

We could have used any of the crop residues as an example feedstock in the following discussion, since similar logistics apply to all of them. We chose to use corn stover, e.g., the stalks, leaves, and cobs that remain following grain harvest, since it is likely to represent a significant portion of cellulosic feedstocks in the future. Since there is no equipment specifically designed to harvest corn, the system we describe below uses combines, mowers, rakes, balers, and bale haulers already in use for harvesting hay or straw. Differences in stalk or stem diameter and density, bale density, moisture content, machine field speeds and efficiencies are a few things that make it relatively more difficult to harvest stover than hay or straw. One of the main concerns is that the density of the large stover bales, whether round or rectangular, can be as little as one-half that of similar dimension hay bales, which usually translates into higher transportation costs.[1092]

Most biomass feedstocks must be harvested, stored, and transported to a processing facility before they can be converted into ethanol. At present, there are no commercial sized cellulosic ethanol plants in the U.S. Likewise, there are no commercially proven, fully-integrated feedstock supply systems dedicated to providing any of the crop residues or other feedstocks to ethanol facilities of any size. We emphasize ‘integrated feedstock supply systems’ because logistically the delivery of a feedstock to a processing facility will require the planning, executing, and controlling of several different, closely integrated operations, e.g., feedstock harvesting, gathering, storing, and moving by road and rail. Apart from the large numbers and wide variety of equipment, these operations will require professional and technical support services and personnel such as office space, staff, and office equipment such as computers and printers. Also, engineers, light- and heavy-duty equipment operators, vehicle maintenance personnel and repair and storage facilities for tractors, rakes, balers, loaders, and trucks and trailers, as well as transportation infrastructure planning and management.

Ordinarily, to determine the operational sufficiency and efficiency of such a system, we would ‘analyze’ it. We would first break it down into its component parts or essential features and then study them, e.g., how much they cost, and how and/or whether they operate efficiently within the ‘system.’ However, no such system currently exists. Therefore, we ‘synthesized’ a feedstock supply system in order to analyze it. We used a Purdue University, School of Industrial Engineering simulation study of corn stover logistics from satellite storage to an ethanol plant, to set up our feedstock harvesting and gathering operation. Purdue’s notional cellulosic ethanol plant was to be constructed next to an actual existing corn grain plant in northern Indiana. They used discrete event simulation software and GIS tools to study the transportation logistics associated with supplying the conversion facility directly from satellite storage. They identified 785,200 available acres out of 848,453 potential acres, on 2,052 actual farms, of 200-, 400-, or 800-acres, in 12 northern Indiana counties within 50-miles of the production facility (they disregarded fields or farms of less than 200-acres). We reproduced their original table as Table. 4.1-7.

## Table 4.1-7.
## Feedstock Availability at Various Distances From South Bend, IN

| | | | | Average Farm Size | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| Average Distance | County | Actual Acres | Cumulative Acres | 200 | 400 | 800 | Available Acres | Cumulative Acres | bales/ day | bales/day /farm set |
| | | | | | Acres | | | | | |
| 12 | St Joseph | 69 | 69 | 74 | 51 | 35 | 63 | 63 | 4,956 | 4,956 |
| 25 | Elkhart | 150 | 219 | 90 | 47 | 23 | 55 | 118 | 4,328 | 10,257 |
| | Marshall | | | 110 | 52 | 41 | 76 | 194 | 5,928 | |
| 30 | La Porte | 113 | 332 | 113 | 73 | 70 | 108 | 302 | 8,453 | 8,453 |
| 35 | Starke | 60 | 392 | 34 | 39 | 41 | 55 | 357 | 4,328 | 4,328 |
| 40 | Kosciusko | 93 | 485 | 108 | 66 | 43 | 82 | 439 | 6,461 | 6,461 |
| 45 | Lagrange | 132 | 617 | 53 | 47 | 20 | 45 | 485 | 3,560 | 9,049 |
| | Fulton | | | 86 | 66 | 43 | 70 | 555 | 5,489 | |
| 50 | Porter | 225 | 842 | 76 | 59 | 34 | 66 | 621 | 5,175 | 18,224 |
| | Noble | | | 115 | 47 | 21 | 59 | 679 | 4,595 | |
| | Pulaski | | | 39 | 72 | 64 | 108 | 787 | 8,453 | |
| | | 842 | | 998 | 619 | 435 | 787 | | 61,726 | 61,728 |

We initially assumed that the stover had been harvested (square bales), gathered, field-transported, and stored at seven-satellite storage areas located near the corn fields.[1093] However, upon further study, we determined the counties that Purdue combined into each of the farm sets, weren't anywhere near each other. In reality, it would have been far too costly to gather all the bales from the Porter, Noble, and Pulaski counties into one site, because these three counties are actually separated by other counties. Rather than try to construct seven satellite storage sites, we constructed a site at the center of each county. This was done in order to estimate the cost to collect the bales from all the fields in each county. We determined that the distance from the center of each of the Porter, Noble, and Pulaski counties, as well as the other two so-called farm-sets, to the ethanol plant was about equal, so regardless of whether we treat them as single sites, the transport costs for the bales to the ethanol plant will be the same. We 'synthesized' the feedstock system to harvest, gather, field transport, and store stover bales at the 11-notional satellite storage units rather than the seven farm-set units used in the Purdue transportation model (our study was not done in conjunction with the Purdue study; rather we used their information/data as the basis from which to synthesize our notional operation). The format we chose to analyze was to shred, rake, square-bale, gather, field-side, and then load and haul the bales to satellite storage; then, as needed, haul the bales to the processing plant.

Rather than guess at how such a system should look and function, we carefully studied several similar systems that were put forward by various agricultural and biological experts.[1094, 1095, 1096, 1097, 1098, 1099, 1100, 1101, 1102] We used the American Society of Agricultural and Biological Engineers (ASABE), 2007 Standards, Engineering Practices, and Data as the primary source for our equipment capital and operating cost estimates. It has a machinery management section, ASE EP496.3, FEB2006, devoted to providing helpful information in making management decisions involving machine power requirements, capacities, cost, selection, and replacement, as well section ASAE D497.5 FEB2006, with data which includes representative values of farm machinery operating parameters, to aid managers, planners, and designers in estimating the performance of field machines. These data are intended for use with ASAE EP496 (some data are also presented in equation form for easier use with computers, etc.).[1103] We used these sections along with other examples by other experts to estimate the machinery capital and operating costs for our analysis.[1104, 1105, 1106, 1107, 1108] We were able to get some machinery purchase prices from vendors whose identities are confidential. We reduced the equipment listed price by 10% to determine the purchase price, a standard industry estimating practice. Otherwise, most of the data used to calculate machinery costs were generated with equations and appropriate data from the ASABE 2007 Standards. We used the equipment, list and purchase prices, along with their power and size estimates, with the suggested data and equations, mentioned previously, to calculate the lifetime hours and years, annual use, field efficiency, salvage value, fuel and oil use and cost (we obtained vendor quotes for oil cost), capital charge, repairs, insurance, housing, taxes, and labor. We compared our data, where appropriate, with the USDA 2006 Price Summary, published July 2007.[1109] We also compared our results with those generated by the experts we listed earlier in this paragraph.

The Purdue study was based on supplying a 100-million gallon per year ethanol production facility, which they assumed would convert the stover-to-ethanol at 72-gallons per ton; they assumed that 2-dry tons corn stover could be harvested per acre, as did we. We used National Agricultural Statistical Service (NASS) data to determine the actual corn grain yield in 2005 (the data year for the Purdue study) for the counties studied in the simulation. We determined how much corn each county produced and from that how much stover was produced, 2,455,000 tons or 3.12 dry tons per acre, with an assumed harvest index (HI) of 1:1 (see Table. 4.1.1.2.2.)[1110] HI is based on the assumption that, for a single corn plant, half of the above ground dry matter is made up of stover and the other half is made up of grain. This is a fairly common assumption, although more than one group of researchers has found that this 1:1 ratio may not be the most accurate under some conditions. When considering above ground dry matter before and after full grain physiological maturation, they found that a stover to grain ratio of 0.8 to 1 may be more realistic especially when grain moisture is between 18 and 31 percent.[1111]

**Table 4.1-8.**
**NASS Indiana Data and Purdue Data Comparison**

| USDA-NASS – Counties in State of Indiana - 2005 | | | | | Purdue Model Year – 2005 | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | Planted | Harvested | Grain Yield | Grain Production | Model | Available Acres | Prorated Grain Production | Wet Tons Stover | Dry Tons Stover |
| County | acres x $10^3$ | acres x $10^3$ | bu/ acre | bu x $10^6$ | acres x $10^3$ | acres x $10^3$ | bu x $10^6$ | x $10^3$ | x $10^3$ |
| St Joseph | 71 | 70 | 147 | 10.2 | 69 | 65 | 9.5 | 266 | 225 |
| Elkhart | 60 | 53 | 142 | 7.6 | 150 | 52 | 7.4 | 206 | 174 |
| Marshall | 94 | 89 | 150 | 13.4 | 0 | 87 | 13.1 | 366 | 309 |
| La Porte | 117 | 112 | 137 | 15.3 | 113 | 104 | 14.2 | 398 | 336 |
| Starke | 61 | 60 | 137 | 8.2 | 60 | 56 | 7.7 | 214 | 181 |
| Kosciusko | 102 | 100 | 149 | 14.9 | 93 | 93 | 13.8 | 386 | 326 |
| Lagrange | 55 | 51 | 113 | 5.8 | 132 | 45 | 5.0 | 141 | 119 |
| Fulton | 90 | 89 | 159 | 14.1 | 0 | 78 | 12.3 | 345 | 291 |
| Porter | 68 | 67 | 137 | 9.2 | 225 | 61 | 8.4 | 234 | 198 |
| Noble | 65 | 62 | 142 | 8.8 | 0 | 57 | 8.0 | 225 | 190 |
| Pulaski | 103 | 101 | 152 | 15.3 | 0 | 92 | 13.9 | 390 | 330 |
| | | 855 | | | 842 | 787 | | 3,172 | 2,455 |

However, a professor of agricultural engineering at the University of Wisconsin found that several researchers, going back to 1973 reported a grain mass fraction of 45% to 55% of total corn crop DM yield. On average, the variations seem to confirm the common rule of thumb of one unit mass of stover for a unit mass of grain. However, differences among harvesting methods, stages of maturity, and harvest dates can no doubt lead to much of the variation the researchers found in this estimate. His research indicates that the ratio of grain dry mass to total mass increased from about 38% in late August to about 59% in mid-October, during a recent harvest. Therefore, the stover to total ratio declined from 62% to 41%. During the typical harvest period in the Upper Midwest when grain moisture is between 20% and 30%, the ratio of stover to total dry mass was less than 45% and averaged 43%. These results are similar to those found by others.[1112] Mainly, because we have no information upon which to base a reason to use something different, we chose to use the 1:1 ratio for corn stover to corn grain. We also assumed 56-lbs per wet bushel (15.5% moisture) and 47.3-lbs per dry bushel, for the corn grain, to make our stover yield calculations.[1113] Table 4.1-9 summarizes the general operating parameters for our study.

**Table 4.1-9. Operating Parameters**

| | |
|---|---|
| EtOH Operating Year | 350-days/yr |
| On Stream Factor | 0.96 |
| Hours per year | 8,400-hr/yr |
| EtOH Production Rate | 100,000,000-gal/yr |
| EtOH Yield | 72-gal/dry ton |
| Feedstock Required | |
| per year | 1,389,000-dry tons/yr |
| per day | 3,970-dry tons/day |
| Expected Dry Matter Loss | 11.8% |
| Feedstock Harvested | 1,574,000-dry tons/yr |
| Feedstock Yield | 2-dry tons/acre |
| Harvest Period | |
| Days, | 50-days |
| Hours per Day | 16-hr/day |
| Harvest Hours | 800-hr |
| Format: | Shred/Rake, |
| | Bale - Lg. Sq. - 3'x4'x8' |
| | Field Side - Self-Propelled Wagon |
| | Satellite Storage – Pole Barn on Concrete |
| | Transport to EtOH Facility – Truck & Trailer |

At 72 gallons per dry ton, the processing plant would require 1,389,000 dry tons of stover per year. However, we believe storage and transportation losses can be significant and should be taken into account. If, as stated in the report, they harvested 2-tons per acre, they actually harvested 1,574,000 tons of stover, or 64% of the 2,455,000 tons of available dry stover. The quantity of stover used versus the quantity harvested represents an 11.8% loss.[RRRRRRRRR] Thus, we assumed that with an 11% loss, we would need to harvest 4,500- dry tons of stover per day, which by the time it reaches the plant will actually equal 3,970-dry tons – the amount required per day at the ethanol plant. During a 350-day production year, 1.574-million tons of stover would have be stored in about 3.5-million, 900-lb bales (Purdue study bale weight), at the various satellite storage areas. For this study, we assumed all the loss took place between the satellite storage areas and the ethanol plant, rather than guess what the losses would be at various points within the harvest/transport scheme.

In the following analysis, we did not account for the extra time or equipment that would be necessary for inevitable break-downs. Nor was time and equipment factored in for driving between fields and for weather delays. Stover suppliers face several, in some cases, difficult problems. At best, the actual harvest period is nearly always too short; winter weather can suddenly set in, which in some cases may completely stop a potential stover or straw harvest. Once the grain is harvested and the stalks are mowed, stover usually must be left in the field for three or four days to dry to below 20% moisture before it's baled, otherwise spoilage or rot as well as spontaneous combustion are possible. If it rains, additional time is required for drying and muddy roads and fields can be badly damaged and the field-soil compacted by the increased

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[RRRRRRRRR] We indicated in a previous section that there may be as little as 25% to 50% stover actually available; however, since we didn't have the computer software and database Purdue used and therefore couldn't rerun the simulation, we chose to use the data we had.

heavy-weight harvest and transport equipment traffic. One expert commented that, "If there's a rainy harvest, you might as well forget about it. Also, the longer the wet material is left in the field, there's more of a chance for microbes to eat away at the hemicellulose."[1114] Delayed baling also raises the chances of dry matter loss. The stover needs to field-dry, so the stover harvest can't actually begin for at least a few days after the grain harvest starts. But, once it begins it can continue until either it's finished or until winter weather stops it.

For reasons that weren't explained in the report, the researchers at Purdue chose 50-days for the harvest period, which at their 16-hr per day schedule, provided a total of 800-hrs to complete the harvest and store the stover. In this harvest format (800-hrs), most of the machinery will be stored for the balance of the year. Crop harvest schedules in the Midwest and upper-Midwest are determined by the length of the growing season, the time of year when the crops are mature enough to harvest, and the time when winter weather sets in. Under ordinary conditions, farmers use their harvesting machinery during just a few weeks each year. During the past few years, as machinery costs have risen, many farmers have turned to custom harvesters, that move into an area and harvest several farms. A farmer must always weigh the differences in the custom rates and what it would cost him to own the equipment and complete the harvest himself, but then store most of the harvesting machinery for the rest of the year. In the South, winters are milder and it's possible to harvest some crops all year long. In such cases, feedstocks could conceivably be harvested and shipped to a conversion facility on an 'as needed' basis; storage costs could be saved and machinery would be used all year long. However, an important factor, when it comes to harvest machinery, is the usable-life of the equipment. The more hours used each year, the more often the machine will need to be replaced. A machine lasts only so many hours, whether it's used 800-hrs per year or 8,000-hours per year. We obviously could have arbitrarily chosen some longer period, but in order to maintain at least some consistency with the Purdue study, we chose to use the 50-day schedule for our study. This short period means we must harvest and store a full year's inventory within a few weeks.

*Mow, Shred, Rake:* Modern corn combines strip most of the leaves from a corn stalk, but leave up to about half of the stalk standing when they cut it off just below the bottom ear. In the combine, the corn grain is stripped from the cob, and the top part of the stalk, the leaves, and the cobs are subsequently discharged out the spreader at the rear of the machine. According to a group of researchers, at the time of grain harvest, of the total stover dry mass, 16% resides in the cob, 7% in the husk, 16% in the leaves, and 60% in the stalk fractions. Of the stalk dry mass, roughly 45% is found in the bottom one-quarter and 80% in bottom one-half of the stalk. If stover yield is to be maximized, harvesting systems must be developed that allow the bottom half of the stalk to be fully harvested.[1115] We summarized the costs to shred and rake in Table 4.1-10

## Table 4.1-10. Corn Stover Shredding & Raking Operation

| | | Tractor – 245-hp | Flail-Shredder -30’ | Tractor 75-hp MFWD | Wheeled V-Rake - 20 ft |
|---|---|---|---|---|---|
| Equipment Factors | | | | | |
| Purchase price | $ | 144,502 | 28,733 | 59,383 | 3,660 |
| Useful life | yrs | 11.3 | 3.1 | 11.3 | 15 |
| Discounted Salvage value | $ | 11,736 | 0.00 | 7,861 | |
| Annual use | hr | 800 | 800 | 800 | 800 |
| Fixed Costs | $/hr | | | | |
| Depreciation and interest | | 25.47 | 14.51 | 10.06 | 1.87 |
| Taxes Insurance Housing (THI) | $/hr | 3.97 | 0.79 | 1.63 | 0.10 |
| Total Fixed Costs | $/hr | 29.44 | 15.30 | 11.69 | 1.97 |
| Variable Costs | | | | | |
| Repairs and maintenance | $/hr | 19.62 | 14.05 | 8.06 | 1.63 |
| Fuel consumption[sssssssss] | gal/hr | 9.6 | 8 | 5.6 | |
| Fuel and lubrication | $/hr | 23.82 | 19.87 | 13.81 | 4.27 |
| Operating Interest | | 1.70 | 1.21 | 0.82 | 0.21 |
| Labor | $/hr | 15.91 | 15.91 | 15.91 | 4.00 |
| Total Variable Cost | $/hr | 61.05 | 51.04 | 38.60 | 10.11 |
| Total Costs | | | | | |
| Total | $/hr | 90.49 | 66.34 | 50.29 | 12.08 |
| Equipment capacity | MT/hr | 32.7 | | 13.27 | |
| Total | $/ton | 4.80 | | 4.70 | |

It will likely be necessary to flail-cut or mow the standing-stalks, and then rake and bale the windrows. We estimated that it cost about $4.80 per ton of stover for shredding and about $4.70 per ton for raking.

*Bale:* As previously discussed, large square bales will likely be the bale-format for this system, although large round bales could be used. There are currently more round balers than square balers in use, mainly because large square balers are more expensive. However, gathering, stacking, and transporting large, round bales is much less efficient. It is difficult to stack round bales more than about three high, since they tend to deform rather badly, during even short storage periods; square bale stacks can be stacked up to five or six bales high, which translates into a more efficient use of storage area as well as more stable stacks that are far less prone to deformation over extended storage periods. Although large round bales tend to weather better out in the open, for the reasons just stated as well as those given in the Purdue report, we used large square bales in this analysis. Table 4.1-11 summarizes the cost of the baling operation, which we estimate to be $10.87 per ton.[1116, 1117]

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[sssssssss] We have received comment that it may be inappropriate to assign a fuel usage to both the 245-hp tractor and the flail shredder. We were unable to determine whether this was the case. The impact of not including such fuel would be a decrease in the price per ton cost of $0.61.

### Table 4.1-11. Corn Stover Baling Operation

| | | Tractor - 275-hp | Lg. Sq. Baler - 3' x 4' x 8' |
|---|---|---|---|
| Equipment Factors | | | |
| Purchase price | $ | 147,102 | 110,723 |
| Useful life | yrs | 11.3 | 3.8 |
| Discounted Salvage value | $ | 7,553 | 32,455 |
| Annual use | hr | 800 | 800 |
| Fixed Costs | $/hr | | |
| Depreciation and interest | | 25.93 | 36.74 |
| Taxes Insurance Housing (THI) | $/hr | 4.05 | 3.04 |
| Total Fixed Costs | $/hr | 29.98 | 39.78 |
| Variable Costs | | | |
| Repairs and maintenance | $/hr | 19.98 | 45.11 |
| Fuel consumption[TTTTTTTTT] | gal/hr | 10 | 8 |
| Fuel and lubrication | $/hr | 24.84 | 19.87 |
| Operating Interest | | 1.71 | 2.38 |
| Labor | $/hr | 15.91 | 10.66 |
| Total Variable Cost | $/hr | 62.44 | 78.02 |
| Total Costs | | | |
| Total | $/hr | 92.42 | 117.80 |
| Equipment capacity | DMT/hr | 19.4 | |
| Total | $/ton | 10.87 | |

*Bale Pick-Up & Field Side:* It is important to remove the stover bales from off the fields. Few farmers will tolerate bales left for long periods on their fields, especially if there is a chance spring planting will be negatively affected. Nor do we expect farmers will allow random piles of bales left at field edges, for retrieval over the winter and spring months. Aside from the likelihood that trucks and other equipment would get stuck in muddy roads and fields, thus slowing down deliveries and running up operating costs, farmers would have little tolerance for torn-up roads and fields. This may not be a big problem, if the farmer/grower intends to plow a field in the spring. However, it could be highly problematic for a farmer/grower who “no till” farms and would be forced to repair ruts and holes in fields and roads before spring planting. Apart from this, dry matter losses from bales, left out in the open on dirt, can be as high as 10% to 20%. At harvest time, the bales, regardless of format, must be picked up and hauled either to a satellite storage site for intermediate storage or hauled directly to the processing plant.

Several variables must be taken into account for bale pickup and the field-side haul operation that could easily affect the cost. Because the exact location on a field where a bale lands as it falls from a baler varies according to stover yield and harvest efficiency, there is no easy or accurate method for predicting the exact location of each bale on the field, either relative to each other or to the field edges or entry. The distance between bales and the potential variability in the area, shape, and relative dimensions of each field add to the difficulty of estimating bale pickup costs. If it was possible to somehow tag each bale with GPS coordinates as it fell to the ground, theoretically the coordinates could be used in some type of ‘bale retrieval’ program to optimize the time and pickup distance traveled.[1118, 1119]

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[TTTTTTTTT] We have received comment that it may be inappropriate to assign a fuel usage to both the 275-hp tractor and the baler. We were unable to determine whether this was the case. The impact of not including such fuel would be a decrease in the price per ton cost of $1.06.

For this study, we used the theoretical stover density on the field, the speed and width of the harvester to estimate the distance between bales. We used a spreadsheet with these data to position the bales in a variety of patterns on a notional rectangular 100-acre field. We devised three or four drive-patterns in which the bales could be retrieved, by using simple visual inspection. We calculated the time to pick up the bales using each pattern and the average speed of the self-propelled bale-wagon. There were a few variables for which we couldn't adjust our numbers because we simply had no way of knowing their effect. For example, if the field was furrowed, it seemed that the less time spent driving across the furrows, at, as we assumed a slower speed than could be traveled along the furrows, the more efficient would be the pick up. Table 4.1-12 summarizes the information we used for our calculations.

**Table 4.1-12. Bale Pickup and Field-Side**

| | | | |
|---|---|---|---|
| Ft. Between Each Bale | 490 | | |
| Pickup One 10-Bale Load - Ft/Load | 4,901 | | |
| Bales/Acre | 4.4 | | |
| Bales/Load | 10 | | |
| Tons/Load | 4.5 | | |
| Loader Speed - mph | 7.5 | | |
| Field Size - Acres | 200 | 400 | 800 |
| Number of Loads per Field Size | 89 | 178 | 356 |
| Bales/Field Size - Total | 889 | 1,778 | 3,556 |
| Miles Traveled per Load | 1.74 | 2.05 | 2.51 |
| Tons/Hour | 26 | 22 | 18 |
| Cost per Ton – Pickup & Field-Side | $2.82 | $3.31 | $ 4.05 |

In any case, using our basic assumptions, the time it took to retrieve a 10-bale load didn't vary significantly for any of our plots. Table 4.1-13 presents the operating data for the bale wagon.

## Table 4.1-13. Self-Propelled Bale-Wagon

| | | Bale Wagon |
|---|---|---|
| Equipment Factors | | |
| Purchase price | $ | 153,716 |
| Useful life | yrs | 18.1 |
| Discounted Salvage value | | 6,013 |
| Annual use | hr | 800 |
| Fixed Costs | $/hr | |
| Depreciation and Interest | $/hr | 20.70 |
| Taxes Insurance Housing (THI) | $/hr | 4.23 |
| Total Fixed Costs | $/hr | 24.93 |
| Variable Costs | | |
| Repairs and Maintenance | $/hr | 12.96 |
| Fuel Consumption gal/hr | | 7 |
| Fuel and Lubrication | $/hr | 17.39 |
| Operating Interest | | 1.21 |
| Labor | $/hr | 15.91 |
| Total Variable Cost | $/hr | 47.47 |
| Total Costs | $/hr | 72.40 |
| Total | $/hr | 72.40 |
| Equipment capacity | DMT/hr | 23 |
| Total | $/ton | 3.15 |

Since the fields were no smaller than 200-acres, we piled the bales at one of the corners, which we assumed as the field-entry. We calculated the cost to haul bales for each of the 200-, 400-, and 800-acre fields. We assumed the 20-ft rake made 148-passes across the 200-acre field; 209-passes across the 400-ft field; and 295-passes across the 800-ft field. We used the number of windrows the rake left to determine the number of passes the baler would make. The baler dropped a bale every 490-ft; to collect a 10-bale load the loader would need to travel 4,900-ft. We estimated that the average distance every bale would need to travel to the corner of the field, e.g., the field entry, would be the distance from the field center to the corner (field-entry); we assumed the fields were square. The loader would need to travel that distance and then return empty, for the next load. Therefore, each loader would travel 4,900-ft to pickup the load, and then an additional 4,174-ft for the 200-acre field; 5,903-ft for the 400-acre field; and 8,348-ft for the 800-acre field to haul to the field edge (corner) and return. We chose to pick up 10-bales per load with a self-propelled bale wagon with an average speed of about 10-mph. We assumed the bales would be picked up, transported, and dumped at the field-edge at a cost of $2.82-per ton for the 200-acre fields; $3.31-per ton for the 400-acre fields; and $4.05-per ton for the 800-acre fields. We weighted the DM hauled for each field size by the total tons recovered from each size, to arrive at 23-weighted dry tons/hr hauled for $3.15-per ton

*Haul to Satellite Storage:* Theoretically, we could store all the bales at the ethanol plant. If so, we would need to move 3,149,000-bales or about 100-loads per hour for 16 hours each day during the 50-day harvest. It would require 50-stacks, each, eight-bales wide by 5-bales high, by 1,577-bales (12,615-ft.) long, with 51 x 20-ft aprons and isles, between each stack and along two-sides of the entire area, plus a 20-ft apron, across the entire front and rear. The area would total ~33-million square feet or 1.19-square miles.

We stored the bales at satellite facilities near the center of each county. As previously discussed, the Purdue study established ‘farm-sets,’ but did not describe how they were configured and how bales were to be hauled to each storage site, nor did the study specify exactly where each storage site was. Rather, they only estimated the distance between each storage area and the ethanol plant. The following table summarizes the cost factors used to estimate the costs to haul the bales to satellite storage.

**Table 4.1-14.**
**Haul - Field Side to Satellite Storage**

| | | High-Speed Tractor | Bale Wagon | 2-Telescopic Handlers |
|---|---|---|---|---|
| Equipment Factors | | | | |
| Purchase price | $ | 133,865 | 23,851 | 130,106 |
| Useful life | yrs | 15 | 15 | 12.5 |
| Discounted Salvage Value | $ | 10,782 | 4,803 | 6,490 |
| Annual use | hr | 800 | 800 | 800 |
| Fixed Costs | $/hr | | | |
| Depreciation and Interest | $/hr | 19.62 | 3.34 | 21.48 |
| Taxes Insurance Housing(THI) | $/hr | 3.68 | 0.66 | 3.58 |
| Total Fixed Costs | $/hr | 23.30 | 4.00 | 25.06 |
| Variable Costs | | | | |
| Repairs and Maintenance | $/hr | 13.63 | 1.94 | 15.90 |
| Fuel Consumption gal/hr | | 6 | 0 | 2 |
| Fuel and Lubrication | $/hr | 14.90 | 0 | 9.94 |
| Operating Interest | $/hr | 1.13 | 0.09 | 1.02 |
| Labor | $/hr | 15.91 | 7.95 | 31.82 |
| Total Variable Cost | $/hr | 45.57 | 9.98 | 58.68 |
| Total Costs | $/hr | 68.87 | 13.98 | 83.74 |
| Total | $/hr | 166.59 | | |
| Equipment capacity | DMT/hr | 9.3 | | |
| Total | $/ton | 17.91 | | |

We assumed that a telescopic loader would load the bales at the field-edges onto 20-bale, 2-axle, 30-ft long wagons, each pulled by a high-speed tractor to the storage area located at the center of each county, where they were unloaded by another telescopic loader and the bales stacked for temporary storage. Several variables make the cost of this operation difficult to estimate. A cursory inspection of the general outline/shape of many of the counties in the study reveals that they are by no means square. However, to make our calculations manageable, we assumed they were in order to determine the average distance each bale would need to be transported to its respective storage area in each county. We estimated that the average distance any load would travel from any position in the counties, e.g., from the furthest to the nearest, would be equal to one-half the distance from the corner of the county to its center. We used the published area of each county, from which we determined the distance from one-corner to the center; that distance equaled the trip to the storage area and the return. We multiplied each by a 30% winding factor (rather than a straight-line drive, this accounts for turns and other meanderings).[1120] We estimated the operation would cost about $17.91 per ton.

*Satellite Storage:* We assumed each storage unit would consist of a concrete slab with open sides and pole-supported tin roof. Smooth paved surfaces are safer and make work easier. Gravel and dirt do not stick to the bottoms of the bales. If winter (wet, muddy) access is necessary, this cost should be included in the overall costs for storage; particularly from the highway to the stack. Beyond the need to keep the area around the stack accessible and clean, there could be problems with local authorities if trucks leaving the property carry significant quantities of mud onto a public highway. Ordinarily, in an agricultural area a certain amount of mud is expected to be left on highways during wet weather. However, at the truck and trailer volumes we're anticipating, the amount being tracked onto highways and possibly through municipalities, would increase rapidly. We used 1% of construction costs for upkeep, and 2% of the construction cost for the storage unit to cover the cost of access. These are incurred costs within the overall maintenance of stored stacks of biomass. These costs are essentially insignificant in the overall storage costs, are subject to great fluctuations due to weather and equipment availability, and, therefore, were rolled up into a percentage of the overall storage costs of stacked bales. The following table summarizes our storage area construction cost factors and costs.

**Table 4.1-15.**
**Satellite Storage Construction & Maintenance Costs – For Each of 11-Areas**

| | | | | | | |
|---|---|---|---|---|---|---|
| Land Rent ($/acre/yr) | 100 | | | | | |
| Land Preparation ($/acre) | 30,000 | | | | | |
| Construction ($/sq ft) | 3.75 | | | | | |
| Upkeep – 1% of Construction ($/ton) | 0.91 | | | | | |
| Access – 2% of Construction ($/ton) | 1.81 | | | | | |
| Depreciation Period (yrs) | 12 | | | | | |
| | Number of Bales | Bale Storage Area (sq ft) | Bale Storage Area (acres) | Tons Stover per site | Supply days | Total Storage Cost |
| St Joseph | 280,889 | 2,943,716 | 67.6 | 126,400 | 28.1 | $1,123,463 |
| Elkhart | 245,333 | 2,571,093 | 59.0 | 110,400 | 24.5 | $981,252 |
| Marshall | 336,000 | 3,521,280 | 80.8 | 151,200 | 33.6 | $1,343,889 |
| La Porte | 479,111 | 5,021,084 | 115.3 | 215,600 | 47.9 | $1,916,286 |
| Starke | 245,333 | 2,571,093 | 59.0 | 110,400 | 24.5 | $981,252 |
| Kosciusko | 366,222 | 3,838,009 | 88.1 | 164,800 | 36.6 | $1,464,768 |
| Lagrange | 201,778 | 2,114,631 | 48.6 | 90,800 | 20.2 | $807,044 |
| Fulton | 311,111 | 3,260,444 | 74.8 | 140,000 | 31.1 | $1,244,342 |
| Porter | 293,333 | 3,074,133 | 70.6 | 132,000 | 29.3 | $1,173,236 |
| Noble | 260,444 | 2,729,458 | 62.7 | 117,200 | 26.1 | $1,041,692 |
| Pulaski | 479,111 | 5,021,084 | 115.3 | 215,600 | 47.9 | $1,916,286 |
| Total | | | | 1,574,400 | 350 | $13,993,510 |
| Total Cost | | | | | | $8.89/ton |

With well-paved surfaces, equipment can be maneuvered regardless of weather, and surfaces can be sloped to enhance drainage. We also assumed the bales would be stored in multiple stacks, 8-bales wide and 5-bales high, and long enough to accommodate the number of bales we expect; there would 20-ft aprons along the outside of the stacks and 20-ft isles between stacks for stacking, stack management, and for general and fire safety.[1121] One researcher determined that the economics of scale, in the current situation, did not really apply. The cost for secondary storage would therefore be approximately equal on a per ton basis regardless of the size of the biofuel production facility. Based on the numbers above, we estimated that storage would cost about $8.89 per ton.[1122] We used this as the cost per ton for the satellite storage as well as for storage at the plant.

We used 11-telehandlers at the storage areas. (However, once the harvest is complete the telehandlers being used for loading and unloading bale wagons during the field-side to storage area operation could possibly be pressed into transport – load, unload service (see Table 4.1-15). If so, the cost to use the telehandlers could be reduced from $3.28 to $3.08 per ton.) Plus 11-telehandlers at the plant to load and unload trucks and trailers that deliver the stover from satellite storage to the plant; extra telehandler time at the plant will be used to move feedstock as needed. The following table summarizes the cost associated with the transportation. The following table summarizes the cost associated with the transportation.

**Table 4.1-16. Haul From Satellite Storage to Plant**

| | Class 8 Truck | 53-ft Flatbed Trailer | 22-Telescopic Handlers |
|---|---|---|---|
| Equipment Factors | | | |
| Purchase price $ | 103,839 | 42,173 | 130,106 |
| Useful life yrs | 20 | 22 | 13 |
| Discounted Salvage Value $ | 4,025 | 931 | 6,490 |
| Annual use hr | 5,600 | 5,600 | 800 |
| Fixed Costs $/hr | | | |
| Depreciation and Interest $/hr | 1.91 | 0.74 | 236.28 |
| Taxes Insurance Housing(THI) $/hr | 0.41 | 0.71 | 39.38 |
| Total Fixed Costs $/hr | 2.31 | 1.45 | 275.66 |
| Variable Costs | | | |
| Repairs and Maintenance $/hr | 1.13 | 3.16 | 174.90 |
| Fuel Consumption gal/hr | 9 | 0 | 2 |
| Fuel and Lubrication $/hr | 33.95 | 0 | 109.34 |
| Operating Interest $/hr | 0.37 | 0.14 | 11.22 |
| Labor $/hr | 17.46 | | 350.02 |
| Total Variable Cost $/hr | 52.91 | 2.31 | $645.48 |
| Total Costs $/hr | 55.22 | 3.76 | 921.14 |
| Total $/hr | 58.97 | | 921.14 |
| Equipment capacity DMT/hr | 4.5 | | 281 |
| Total, each $/ton | 13.10 | | 3.28 |
| Total $/ton | 16.38 | | |

To transport the bales to the ethanol plant, we calculated the ton-weighted average trip-time to be 4.09 hr. We plan to ship 4,497-tons of stover to the plant on each of the 350-operating days. At 17.5-tons per load, we anticipate there will be about 256-loads per day. Using the 4.09-ton weighted trip time, we estimated that it would require 63-trucks and trailers to haul 4 x 17.5-ton per day. The cost of transportation plus loading and unloading is estimated to be $16.38 per dry ton. The following table summarizes all the costs to harvest, bale, field-side, haul to satellite storage, store, and haul to the plant.

**Table 4.1-17.**
**Ag Residue Cost Summary**

| Farm-Set Size, acres | 200 | 400 | 800 | Total Tons |
|---|---|---|---|---|
| Tons per Farm-Set, t | 756,439 | 476,402 | 341,559 | 1,574,400 |
| Farmer/Grower $/t | 10.00 | 10.00 | 10.00 | |
| Nutrient Replace $/t | 11.81 | 11.81 | 11.81 | |
| Shred $/t | 4.80 | 4.80 | 4.80 | |
| Rake $/t | 4.70 | 4.70 | 4.70 | |
| Bale $/t | 10.84 | 10.84 | 10.84 | |
| Haul – Edge $/t | 2.82 | 3.31 | 4.05 | |
| Total Farm Edge Cost $/t | **44.97** | **45.46** | **46.20** | |
| Haul – SS $/t | 17.91 | 17.91 | 17.91 | |
| Storage $/t | 8.89 | 8.89 | 8.89 | |
| Haul to Ethanol Plant $/t | 16.38 | 16.38 | 16.38 | |
| Field to Plant – Total $/t | **43.18** | **43.18** | **43.18** | |
| | | | | |
| Per Farm- Set – Total $/t | 88.15 | 88.64 | 89.38 | |
| Avg. Total Cost $/t | **88.71** | | | |

We anticipate that by 2022 the industry will improve the efficiency of feedstock delivery and reduce the cost of feedstocks. The current harvest-system is usually referred to as a multipass system: the corn grain is first combined, and then the stover is shredded, raked, baled, and the bales hauled to the field side. Each field-pass adds to the final cost and further compacts the soil; soil compaction is especially critical if the soil is prone to compaction or in no-till situations.[1123] Because the combine-spreader drops the stover on to the ground, not only are fewer cobs collected, but dirt, dirt clods, and other debris, including metal, are inevitably gathered up with the stover by the baler.[1124, 1125] Thus, extra effort and money must be expended to remove the debris before processing can begin, apart from the fact that dry matter is also lost during this operation. In their 2002 study report, NREL included a wash table to remove dirt and grit and had magnets to remove tramp iron, e.g., wire, etc. from the stover.[1126]

According to a few sources, which for reasons of confidentiality, we can’t quote, there appears to be active interest in restructuring the system we just described to move the preprocessing (feedstock preparation) forward in the chain, away from the ethanol plant, and closer to the fields. Including the issues highlighted in the previous paragraphs, a major concern has to do with the use of standard hay and forage equipment, for which the overall collection efficiency of stover (ratio of stover collected to the total above-ground stover excluding grain) using flail choppers, rakes, and balers was less than 30%.[1127] Until now, most research has been based on a multi-pass system similar to the one we synthesized.[1128,1129] In addition, the timeliness for collection (weather concerns) and moisture content issues are major problems associated with a multi-pass corn stover harvest.[1130]

The restructuring efforts also include exploring other methods to more efficiently gather the stover that avoids the need to pick it up from the ground, e.g., gather or catch it before it hits the ground.[1131] In one early case, a baler was hitched directly onto a combine, to capture the combine effluent and square-bale it. The problem was that there was a strict need to limit moisture to under 20% if bales are to be stored, plus the extra equipment slowed the grain harvest.[1132] Ideally, the stover harvest system should be capable of harvesting stover at any level of moisture even while the grain is being harvested. All the cobs would be collected, the stover wouldn't touch the ground and a controlled amount of residue would be left to meet any conservation requirements (we believe finding a way to leave the correct amount of residue behind will be difficult, and should be a top priority).

A modification of the system we previously described would be to use a mobile tub grinder that could be towed from one satellite storage area to the next. A telehandler would feed the grinder to directly fill trucks for transport to the production facility. The 'walking floor,' rear-dump, or belly-dump trailers would unload the ground-up stover into silos or tanks at the facility. These silos or tanks could be sized to provide as much feed surge capacity as the facility required to maintain continuous operation.[1133]

Again, ideally, the corn stover harvest should be reduced to a single-pass operation during which the amount of residue left on the field will be less a function of harvest efficiency and more a function of the farmer/grower and the harvesting company being able to determine how much residue must be left to maintain soil health. In reality, most of the equipment doesn't yet exist that could perform some of the operations we will describe. Nevertheless, we believe this reflects some of the forward thinking that is currently taking place. For example, a combine designed specifically for the job must still be constructed. A single-pass harvester would cut the whole stalk a few inches above the soil, leaving some stalk anchored to the ground. It would pull the entire plant, e.g., stalks, leaves, and cobs with grain into the combine, where they are mixed into a single, clean, grain and stover stream. It would then blow the entire stream into tractor-pulled grain-carts that run along-side the harvester. It is important to be able to change full carts for empties without stopping the harvester. As a cart is filled, it is pulled from beneath the discharge tube, as an empty cart is pulled under it. The full cart is hauled to the field side, where the harvested material is unloaded directly into bulk 'walking-floor' semi trailers, for transport to a co-op or depot type elevator/facility. After the biomass stream is unloaded, equipment at the elevator/depot separates the stover from the grain, following which the stover is chopped, dried, and sent to tanks or silos for intermediate storage. Currently, there are no simple methods for drying wet corn stover, other than to let it field-dry. However, if the single-pass harvest is to become a reality, the stover will need to be dried or else stored in much the same way silage is stored.[1134] At harvest, corn grain has a moisture content of 25%, while at the same time, the stover ordinarily ranges from 35% to well over 50% moisture. There have been studies to artificially dry corn stover as well as other biomass types; there will likely be changes to the reported results of these and other studies, but, then we expect advancements and certainly changes in several parts of the feedstock supply system.[1135, 1136, 1137] Given that these changes take place, the stover, would have flowability characteristics similar to small cereal grains, and could be moved by standard grain loading and unloading systems into large corrugated steel bins (silos) for intermediate storage. In this harvest format, the stover is handled by only two machines before it reaches the roadside and never hits the ground. Dry matter losses should be significantly reduced.[1138]

Harvesting, storing, and transporting a denser feedstock should offer significant savings.[1139] Using this and other anticipated improvements, it appears possible that in the out years, e.g., by 2022, corn stover and other residues could be commoditized, much as is the case with grain, and then purchased by a processor on an as-needed basis.

However, commoditization offers its own set of issues, among which are both tangible and non-tangible infrastructures. Although tangible infrastructure with regard to ethanol distribution is discussed in greater detail in Section 4.2, we believe the following comments fit within the context of our preceding information. The impact of both feedstock and finished ethanol on rural road, highway and railroad infrastructure is likely to be even greater than the current and anticipated impact of corn based ethanol. Raw cellulosic feedstocks have lower levels of concentrated fermentable carbohydrates and therefore require a greater mass of feedstock to produce an equivalent level of ethanol. Thus, public and private transportation infrastructure must move a greater volume of feedstock per gallon of ethanol produced. The magnitude of the impact will depend on the field density of feedstocks near the plant and whether feedstock densification will make it possible to ship more dense carbohydrate product to the cellulosic ethanol plant.

Intangible infrastructure is essentially absent for crop residue type cellulosic feedstocks. Intangible infrastructure includes such things as uniform grade and quality standards, market price discovery mechanisms, collateral warehouse receipts, regulatory structure and other marketing institutions. Grain market institutions have been developed and fine-tuned over the past century which provide corn ethanol plants a decided benefit. Daily price information, as well as a wealth of crop condition, and supply and demand information from a variety of public and private sources is available on corn grain. Well known institutions such Uniform Grade and Quality Standards, FGIS, Grain Warehouse Regulations, Collateral Warehouse Receipts, Trade Associations, Non-Recourse Government Commodity Loans, and a set of futures markets that efficiently price grain over time and space are all readily available. This infrastructure is already in place, tested and readily accessible to corn grain ethanol producers. Although not highly visible and frequently taken for granted, it plays a critical role in efficient feedstock pricing, risk management, trading and financing. The cellulosic marketing infrastructure required for similar efficient commercial transactions will need to be established from top to bottom.

Pricing infrastructure is one of the most pressing needs. Large daily volumes of corn and other grains are traded on well established exchanges with a great deal of confidence on the part of buyers and sellers that the other party will perform. Initially, it could be difficult, at best, to develop these infrastructure benefits for crop residues such as corn stover. Cellulosic feedstocks will be starting from a relatively small production base with no pricing institutions in place. There are no existing grades and quality standards to underpin transactions over distance and time. Nor are there any trade rules or established patterns for prompt and efficient settlement of trade disputes between buyers and sellers. The absence of these factors does not mean that they won't develop, but there could be a stressful transition period.

Also, there is no regulatory infrastructure to protect producers who wish to hold inventory after harvest in a public warehouse or handlers warehouse. This kind of infrastructure serves an important role in underpinning warehouse receipts and producer financing by creating a higher and more reliable collateral value for inventory. Nor are there equivalents to the U.S. grain grades and quality standards or Federal Grain Inspection Service. While there are other ways these functions can be provided some type of commodity grades and standards will be necessary to permit trading. Another possibility would be to have the production of cellulosic feedstocks and the production of ethanol vertically integrated in some fashion so that the responsibility for quality is internalized.[1140]

### *Energy Crops*

Energy crops such as switchgrass and miscanthus would be harvested, baled, stored and transported very similar to crop residues. Because energy crops are not currently grown on a commercial scale, and are therefore not harvested, it is difficult to model the costs of harvesting these crops. Given the process for harvesting is likely to resemble the corn stover harvesting system described in our internal analysis of agricultural residue costs, we believe the costs would also be similar. Despite these similarities, there are several key differences that will cause the price of energy crops to differ from that of corn stover and other agricultural residues.

One of the main advantages of growing energy crops is the low nutrient inputs, and therefore low nutrient replacement costs, that are required as compared to traditional crops. Energy crops are also expected to produce higher yields per acre than the harvesting of agricultural residues. This higher density is likely to increase the number of tons of feedstock than can be harvested per hour, while at the same time decreasing the transportation distance between the farms where the feedstock is produced and the biofuel production facility. Both of these factors would further decrease the cost of energy crop production, as labor and transportation costs would be lower and less secondary storage facilities would be required.

Not all of the traits of energy crops would indicate lower costs of production, however. Energy crops will also incur a land rent cost. In the scenario described in our internal analysis for corn stover no land rent cost was charged to the production of corn stover. This is because the stover is assumed to be a secondary crop, and therefore all the land rent charges are assumed to be included in the cost of grain production. Because energy crops will likely be grown as primary crops there will be some land rent cost associated with their production. How big this cost is will vary greatly, depending on where and on what type of land the energy crops are grown. If energy crops are grown on marginal land that is unsuitable for traditional crops, as has been suggested, this cost may be low. In any case, it will be an increase when compared with agricultural residues, which do not have any associated land rent costs[UUUUUUUUU].

### *Wood Residue*

As we did with agricultural residues, we also examined the costs associated with wood residue harvesting to validate the cost generated with FASOM. Harvest and transport costs for woody biomass in its different forms vary due to tract size, tree species, volumes removed, distance to the wood-using/storage facility, terrain, road condition, and other many other considerations. There is a significant variation in these factors within the United States, so timber harvest and delivery systems must be designed to meet constraints at the local level.

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[UUUUUUUUU] Land rent charges are included in the FASOM estimate of the roadside cost of energy crops.

Harvesting costs also depend on the type of equipment used, season in which the operation occurs, along with a host of other factors. Much of the forest residue is already being harvested by logging operations, or is available from milling operations. However, the smaller branches and smaller trees proposed to be used for biofuel production are not collected for their lumber so they are normally left behind. Thus, this forest residue would simply have to be collected and transported out of the forest, although it would still have to be chipped before transport to the biofuel plant.

In general, most operators in the near future will chip at roadside in the forest, blowing the chips directly into a chip van. When the van is full it will be hauled to an end user's facility and a new van will be moved into position at the chipper. The process might change in the future as baling systems become economically feasible or as roll-off containers are proven as a way to handle logging slash. At present, most of the chipping for biomass production is done in connection with fuel-reduction treatments. This could change if the price of raw biomass increases to a point where it becomes feasible to recover logging residues associated with normal commercial operations. The major problem associated with collecting logging residues and biomass from small trees is handling the material in the forest before it gets to the chipper. Balers and roll-off containers offer some promise to reduce this cost. Whether the material is collected from a fuel-reduction treatment or a commercial logging operation, chips from residues will be dirty and will require screening or some type of filtration at the end-user's facility.[vvvvvvvvv]

Results from a study in South Georgia show that under the right conditions, a small chipper can be added to a larger operation to obtain additional chip production without adversely impacting roundwood production, and chips can be produced from limbs and tops of harvested trees at costs ranging from $11 per ton and up. Harvesting understory (the layer formed by grasses, shrubs, and small trees under the canopy of larger trees and plants) for use in making fuel chips is about $1 per ton more expensive.

Per ton costs decrease as the volume chipped increases per acre. Some estimates suggest that if no more than 10 loads of roundwood are produced before a load of chips is made, that chipper-modified system could break even. Cost projections suggest that removing only limbs and tops may be marginal in terms of cost since one load of chips is produced for about every 15 loads of roundwood.

The U.S. Forest Service provided us a cost curve for different categories of forest residue, including logging residue, other removals (i.e., clearing trees for new building construction), timberland trimmings (forest fire prevention strategy) and mill residues.[1141] The data was provided to us on a county-by-county basis. The national forest lands are omitted from consideration, and the urban forest residue is not considered here, but in the section discussing MSW. The information was also provided at different price points. The quantities of forest residue are summarized by source type in Tables 4.1-18, 4.1-19 and 4.1-20. To avoid presenting

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[vvvvvvvvv] Personal Communication, Eini C. Lowell, Research Scientist, USDA Forest Service a huge amount of data, we aggregated the county data by state, and we are presenting the data at specific price points: $30/dry ton, $45/dry ton and $70/dry ton.

# Table 4.1-18.
# Volume of Wood Residue Available for Producing Biofuel
## Biomass Available at $30/ton (dry tons)

| | Logging Residue | Other Removals | Timberland Thinnings | Unused Mill Residue | Total Quantity |
|---|---|---|---|---|---|
| Alabama | 1,202,541 | 253,620 | 433,519 | 7,117 | 1,896,798 |
| Arizona | 8,849 | 22,436 | 33,085 | 1,351 | 65,721 |
| Arkansas | 851,772 | 385,492 | 369,083 | 12,889 | 1,619,236 |
| California | 334,870 | 0 | 871,351 | 65,088 | 1,271,309 |
| Colorado | 9,203 | 7 | 0 | 2,302 | 11,511 |
| Connecticut | 4,195 | 15,339 | 10,465 | 3,949 | 33,949 |
| Delaware | 15,051 | 12,109 | 4,918 | 0 | 32,077 |
| Florida | 535,215 | 257,704 | 240,947 | 2,202 | 1,036,067 |
| Georgia | 1,556,954 | 496,631 | 553,627 | 45,138 | 2,652,350 |
| Idaho | 126,573 | 0 | 41,548 | 6,006 | 174,126 |
| Illinois | 139,101 | 117,589 | 115,431 | 18,523 | 390,644 |
| Indiana | 281,242 | 52,087 | 198,112 | 10,627 | 542,068 |
| Iowa | 56,049 | 27,580 | 48,991 | 159 | 132,780 |
| Kansas | 7,329 | 44,202 | 9,676 | 8,720 | 69,928 |
| Kentucky | 513,989 | 332,179 | 344,948 | 55,196 | 1,246,311 |
| Louisiana | 1,317,139 | 440,293 | 300,924 | 30,075 | 2,088,431 |
| Maine | 1,206,438 | 470 | 80,314 | 42,483 | 1,329,705 |
| Maryland | 90,722 | 415 | 40,994 | 17,067 | 149,197 |
| Massachusetts | 35,461 | 31,043 | 13,801 | 0 | 80,305 |
| Michigan | 379,463 | 122,476 | 327,640 | 13,763 | 843,343 |
| Minnesota | 348,807 | 331,492 | 132,712 | 26,878 | 839,889 |
| Mississippi | 1,548,534 | 355,071 | 425,344 | 95,138 | 2,424,088 |
| Missouri | 387,434 | 265,146 | 342,077 | 79,787 | 1,074,443 |
| Montana | 131,335 | 0 | 66,592 | 9,136 | 207,063 |
| Nebraska | 10,572 | 9,386 | 11,707 | 4,971 | 36,637 |
| Nevada | 15 | 53 | 0 | 0 | 67 |
| New Hampshire | 157,321 | 174 | 47,802 | 7,019 | 212,316 |
| New Jersey | 2,959 | 39 | 2,288 | 1,437 | 6,723 |
| New Mexico | 11,929 | 1,279 | 25,898 | 4,902 | 44,008 |
| New York | 367,003 | 54,671 | 163,336 | 27,390 | 612,400 |
| North Carolina | 1,013,165 | 629,632 | 560,814 | 12,811 | 2,216,422 |
| North Dakota | 1,453 | 7,601 | 3,822 | 265 | 13,141 |
| Ohio | 185,398 | 9,053 | 83,676 | 22,600 | 300,726 |
| Oklahoma | 173,869 | 98,794 | 53,043 | 495 | 326,200 |
| Oregon | 760,276 | 31 | 527,702 | 16,316 | 1,304,326 |
| Pennsylvania | 543,663 | 699 | 224,978 | 170,972 | 940,312 |
| Rhode Island | 884 | 22,860 | 2,800 | 389 | 26,934 |
| South Carolina | 714,551 | 348,289 | 301,850 | 1,051 | 1,365,741 |
| South Dakota | 6,972 | 14,436 | 2,993 | 2,294 | 26,695 |
| Tennessee | 316,706 | 244,920 | 423,906 | 187,583 | 1,173,115 |
| Texas | 616,777 | 218,464 | 185,718 | 3,021 | 1,023,979 |
| Utah | 2,973 | 7 | 9,909 | 4,437 | 17,325 |
| Vermont | 104,876 | 18,652 | 48,395 | 0 | 171,923 |
| Virginia | 741,673 | 406,800 | 436,870 | 39,366 | 1,624,709 |
| Washington | 641,144 | 22 | 925,479 | 21,446 | 1,588,091 |
| West Virginia | 488,356 | 24,714 | 161,653 | 118,779 | 793,502 |
| Wisconsin | 568,800 | 491,132 | 260,293 | 60,410 | 1,380,636 |
| Wyoming | 11,343 | 0 | 14,050 | 34,014 | 59,407 |
| Total | 18,530,943 | 6,165,088 | 9,485,083 | 1,295,560 | 35,476,674 |

## Table 4.1-19.
## Tons of Wood Residue Available for Producing Biofuel
## Biomass Available at $45/ton (dry tons)

| | Logging Residue | Other Removals | Timberland Thinnings | Unused Mill Residue | Total Quantity |
|---|---|---|---|---|---|
| Alabama | 1,202,541 | 253,620 | 506,045 | 7,117 | 1,969,324 |
| Arizona | 13,566 | 21,210 | 34,967 | 1,351 | 71,094 |
| Arkansas | 851,772 | 385,492 | 429,414 | 12,889 | 1,679,567 |
| California | 583,478 | 0 | 949,468 | 65,088 | 1,598,034 |
| Colorado | 10,056 | 11 | 30,619 | 2,302 | 42,988 |
| Connecticut | 4,301 | 16,095 | 10,465 | 3,949 | 34,810 |
| Delaware | 17,932 | 14,145 | 6,700 | 0 | 38,777 |
| Florida | 535,215 | 257,704 | 266,597 | 2,202 | 1,061,718 |
| Georgia | 1,556,954 | 496,631 | 644,295 | 45,138 | 2,743,018 |
| Idaho | 216,303 | 0 | 52,594 | 6,006 | 274,902 |
| Illinois | 139,153 | 117,589 | 115,431 | 18,523 | 390,696 |
| Indiana | 281,464 | 52,087 | 221,845 | 10,627 | 566,023 |
| Iowa | 56,050 | 27,607 | 49,551 | 159 | 133,367 |
| Kansas | 7,329 | 44,202 | 9,676 | 8,720 | 69,928 |
| Kentucky | 513,989 | 332,179 | 407,371 | 55,196 | 1,308,735 |
| Louisiana | 1,317,139 | 440,293 | 330,512 | 30,075 | 2,118,019 |
| Maine | 1,280,511 | 495 | 102,442 | 42,483 | 1,425,931 |
| Maryland | 94,579 | 421 | 40,994 | 17,067 | 153,060 |
| Massachusetts | 39,127 | 33,191 | 13,801 | 0 | 86,119 |
| Michigan | 391,732 | 128,600 | 410,302 | 13,763 | 944,398 |
| Minnesota | 358,518 | 341,894 | 159,990 | 26,878 | 887,280 |
| Mississippi | 1,548,534 | 355,071 | 467,935 | 95,138 | 2,466,679 |
| Missouri | 387,434 | 265,146 | 466,082 | 79,787 | 1,198,448 |
| Montana | 215,597 | 0 | 70,775 | 9,136 | 295,507 |
| Nebraska | 10,710 | 9,434 | 11,707 | 4,971 | 36,822 |
| Nevada | 22 | 71 | 0 | 0 | 93 |
| New Hampshire | 165,519 | 197 | 57,566 | 7,019 | 230,301 |
| New Jersey | 3,184 | 40 | 2,423 | 1,437 | 7,084 |
| New Mexico | 17,239 | 1,287 | 26,862 | 4,902 | 50,291 |
| New York | 384,457 | 56,552 | 189,696 | 27,390 | 658,094 |
| North Carolina | 1,013,165 | 629,632 | 668,420 | 12,811 | 2,324,028 |
| North Dakota | 1,454 | 7,601 | 3,822 | 265 | 13,142 |
| Ohio | 186,022 | 9,069 | 88,572 | 22,600 | 306,263 |
| Oklahoma | 173,869 | 98,794 | 62,700 | 495 | 335,858 |
| Oregon | 1,341,835 | 34 | 574,948 | 16,316 | 1,933,133 |
| Pennsylvania | 1,341,835 | 34 | 574,948 | 170,972 | 2,087,789 |
| Rhode Island | 957 | 25,039 | 2,800 | 389 | 29,185 |
| South Carolina | 714,551 | 348,289 | 352,018 | 1,051 | 1,415,909 |
| South Dakota | 11,872 | 15,581 | 3,253 | 2,294 | 32,999 |
| Tennessee | 316,706 | 244,920 | 507,698 | 187,583 | 1,256,906 |
| Texas | 616,777 | 218,464 | 219,187 | 3,021 | 1,057,448 |
| Utah | 3,758 | 0 | 10,786 | 4,437 | 18,980 |
| Vermont | 108,542 | 19,182 | 53,836 | 0 | 181,560 |
| Virginia | 741,673 | 406,800 | 524,372 | 39,366 | 1,712,212 |
| Washington | 1,067,587 | 23 | 981,839 | 21,446 | 2,070,895 |
| West Virginia | 488,356 | 24,714 | 241,184 | 118,779 | 873,033 |
| Wisconsin | 576,938 | 499,302 | 327,027 | 60,410 | 1,463,677 |
| Wyoming | 18,163 | 0 | 18,202 | 34,014 | 70,380 |
| Total | 20,928,463 | 6,198,742 | 11,301,737 | 1,295,560 | 39,724,502 |

## Table 4.1-20.
## Tons of Wood Residue Available for Producing Biofuels
## Biomass available at $70/ton (dry tons)

| | Logging Residue | Other Removals | Timberland Thinnings | Unused Mill Residue | Total Quantity |
|---|---|---|---|---|---|
| Alabama | 1,202,541 | 253,620 | 581,654 | 7,117 | 2,044,933 |
| Arizona | 13,566 | 24,510 | 38,678 | 1,351 | 78,105 |
| Arkansas | 851,772 | 385,492 | 492,094 | 12,889 | 1,742,247 |
| California | 583,478 | 0 | 1,000,615 | 65,088 | 1,649,181 |
| Colorado | 10,056 | 11 | 30,619 | 2,302 | 42,988 |
| Connecticut | 4,301 | 16,095 | 10,465 | 3,949 | 34,810 |
| Delaware | 17,932 | 14,145 | 6,700 | 0 | 38,777 |
| Florida | 535,215 | 257,704 | 332,353 | 2,202 | 1,127,474 |
| Georgia | 1,556,954 | 496,631 | 776,911 | 45,138 | 2,875,634 |
| Idaho | 216,303 | 0 | 61,926 | 6,006 | 284,235 |
| Illinois | 139,153 | 117,589 | 115,431 | 18,523 | 390,696 |
| Indiana | 281,464 | 52,087 | 221,845 | 10,627 | 566,023 |
| Iowa | 56,050 | 27,607 | 49,551 | 159 | 133,367 |
| Kansas | 7,329 | 44,202 | 9,676 | 8,720 | 69,928 |
| Kentucky | 513,989 | 332,179 | 463,904 | 55,196 | 1,365,268 |
| Louisiana | 1,317,139 | 440,293 | 375,052 | 30,075 | 2,162,559 |
| Maine | 1,280,511 | 495 | 166,117 | 42,483 | 1,489,605 |
| Maryland | 94,579 | 421 | 40,994 | 17,067 | 153,060 |
| Massachusetts | 39,127 | 33,191 | 13,801 | 0 | 86,119 |
| Michigan | 391,732 | 128,600 | 533,107 | 13,763 | 1,067,203 |
| Minnesota | 358,518 | 341,894 | 200,599 | 26,878 | 927,889 |
| Mississippi | 1,548,534 | 355,071 | 516,598 | 95,138 | 2,515,342 |
| Missouri | 387,434 | 265,146 | 643,929 | 79,787 | 1,376,295 |
| Montana | 215,597 | 0 | 83,023 | 9,136 | 307,755 |
| Nebraska | 10,710 | 9,434 | 11,707 | 4,971 | 36,822 |
| Nevada | 22 | 71 | 0 | 0 | 93 |
| New Hampshire | 165,519 | 197 | 58,098 | 7,019 | 230,833 |
| New Jersey | 3,184 | 40 | 2,423 | 1,437 | 7,084 |
| New Mexico | 17,239 | 1,287 | 32,187 | 4,902 | 55,616 |
| New York | 384,457 | 56,552 | 192,851 | 27,390 | 661,249 |
| North Carolina | 1,013,165 | 629,632 | 800,455 | 12,811 | 2,456,063 |
| North Dakota | 1,454 | 7,601 | 3,822 | 265 | 13,142 |
| Ohio | 186,022 | 9,069 | 88,572 | 22,600 | 306,263 |
| Oklahoma | 173,869 | 98,794 | 81,634 | 495 | 354,792 |
| Oregon | 1,251,094 | 34 | 566,594 | 16,316 | 1,834,037 |
| Pennsylvania | 546,418 | 707 | 340,497 | 170,972 | 1,058,594 |
| Rhode Island | 957 | 25,039 | 2,800 | 389 | 29,185 |
| South Carolina | 714,551 | 348,289 | 395,555 | 1,051 | 1,459,446 |
| South Dakota | 11,872 | 15,581 | 4,129 | 2,294 | 33,875 |
| Tennessee | 316,706 | 244,920 | 516,550 | 187,583 | 1,265,759 |
| Texas | 616,777 | 218,464 | 253,670 | 3,021 | 1,091,931 |
| Utah | 3,758 | 7 | 14,717 | 4,437 | 22,918 |
| Vermont | 108,542 | 19,182 | 71,105 | 0 | 198,829 |
| Virginia | 741,673 | 406,800 | 630,366 | 39,366 | 1,818,206 |
| Washington | 1,067,587 | 23 | 1,029,985 | 21,446 | 2,119,041 |
| West Virginia | 488,356 | 24,714 | 287,639 | 118,779 | 919,489 |
| Wisconsin | 576,938 | 499,302 | 420,775 | 60,410 | 1,557,425 |
| Wyoming | 18,163 | 0 | 21,598 | 34,014 | 73,775 |
| Total | 20,042,304 | 6,202,722 | 12,593,373 | 1,295,560 | 40,133,959 |

The relatively flat supply curve indicates that small changes in the demand for wood residues could have a significant impact on the cost of these residues. This makes predicting an appropriate cost for these residues a difficult task. The FASOM model estimates that 1.67 million dry tons of wood residues will be used in cellulosic biofuel production in 2022. This number is far less than the 35.5 million dry tons of wood residue that the US Forestry service estimates will be available at $30 a ton. This would suggest that the low costs estimated by FASOM ($19.77 per dry ton) are reasonable.

Delivery of woody biomass from the harvesting site to a conversion facility, like delivery of more conventional forest products, accounts for a significant portion of the delivered cost. In fact, transportation of wood fiber (including hauling within the forest) accounts for about 25 to 50 percent of the total delivered costs and highly depends on fuel prices, haul distance, material moisture content, and vehicle capacity and utilization. Also, beyond a certain distance, transportation becomes the limiting factor and the costs become directly proportional to haul distance. We believe Class 8 over-the-road hauling will be used to transport the wood residues from the roadside to the biofuel production facilities. The cost for the transportation of wood residues was determined using the transportation and secondary storage tool presented in Section 1.3 and in further detail below. Because wood residues can be harvested throughout the year and delivered to the biofuel production plant on an as needed basis no secondary storage costs were included.

*Municipal Solid Waste*

Million of tons of municipal solid waste (MSW) continue to be disposed of in landfills across the country, despite recent large gains in waste reduction and diversion. The biomass fraction of this total stream represents a potentially significant resource for renewable energy (including electricity and biofuels). Because this waste material is already being generated, collected and transported (it would solely need to be transported to a different location), its use is likely to be less expensive than other cellulosic feedstocks. One important difficulty facing those who plan to use MSW fractions for fuel production is that in many places, even today, MSW is a mixture of all types of wastes, including biomaterials such as animal fats and grease, tin, iron, aluminum, and other metals, painted woods, plastics, and glass. Many of these materials can’t be used in biochemical and thermochemical ethanol production, and, in fact, would inflate the transportation costs, impede the operations at the biofuel plant and leave an expensive waste stream for biofuel producers.

Thus, accessing sorted MSW would likely be a requirement for firms planning on using MSW for producing cellulosic biofuels. In a confidential conversation, a potential producer who plans to use MSW to produce ethanol indicated that their plant plans are based on the obtaining cellulosic biowaste which has already been sorted at the waste source (e.g., at the curbside, where the refuse hauler picks up waste already sorted by the generating home-owner or business). For example, in a tract of homes, one refuse truck would pick up glass, plastic, and perhaps other types of waste destined for a specific disposal depot, whereas a different truck would follow to pick up wood, paper, and other cellulosic materials to be hauled to a depot that supplies an ethanol plant. However, only a small fraction of the MSW generated today is sorted at the curbside.

Another alternative would be to sort the waste either at a sorting facility, or at the landfill, prior to dumping. There are two prominent options here. The first is that there is no sorting at the waste creation site, the home or business, and thus a single waste stream must be sorted at the facility. This operation would likely be done by hand or by automated equipment at the facility. To do so by hand is very labor intensive and somewhat slower than using an automated system. In most cases the 'by-hand' system produces a slightly cleaner stream, but the high cost of labor usually makes the automated system more cost-effective. Perhaps the best approach for low cost and a clean stream is the combination of hand sorting with automated sorting.

The third option is a combination of the two which requires that there is at least some sorting at the home or business which helps to prevent contamination of the waste material, but then the final sorting occurs downstream at a sorting site, or at the landfill.

We have little data and few estimates for the cost to sort MSW. One estimate from our Office of Solid Waste for a combination of mechanically and manually sorting of a single waste stream downstream of where the waste is generated puts the cost in the \$20 to \$30 per ton range. There is a risk, though, that the waste stream could still be contaminated and this would increase the cost of both transporting and using this material at the biofuel plant due to the toxic ash produced which would require disposal at a toxic waste facility. If a less contaminated stream is desired it would probably require sorting at the generation site – the home or business - which would likely be more costly since many more people in society would then have to be involved and special trucks would need to be used. Also, widespread participation is difficult when a change in human behavior is required as some may not be so willing to participate. Offering incentives could help to speed the transition to curbside recycling (i.e., charging fee for nonsorted waste, or paying a small amount for sorted tree trimmings and construction and demolition waste). Assuming that curbside sorting is involved, at least in a minor way, total sorting costs might be in the \$30 to \$40 per ton range.

These sorting costs would be offset by the cost savings for not disposing of the waste material as well as the value of the recovered materials. Most landfills charge tipping fees, the cost to dump a load of waste, a societal cost that would be avoided. In the United States, the national average nominal tipping fee increased fourfold from 1985 to 2000. The real tipping fee almost doubled, up from a national average (in 1997 dollars) of about \$12 per ton in 1985 to just over \$30 in 2000. Equally important, it is apparent that the tipping fee is much higher in densely populated regions. Statewide averages also varied widely, from \$8 a ton in New Mexico to \$75 in New Jersey. Tipping fees ranged from \$21 to 98 per ton in 2006 for MSW and \$18/ton to \$120/ton for construction and demolition waste. It is likely that the tipping fees are highest for waste contaminated by toxic materials that require the disposal at Resource Conservation and Recovery Act (RCRA) certified toxic waste sites as opposed to a composting site. However, this same contaminated material would not be desirable to biofuel producers. Presuming that only the noncontaminated cellulosic waste (yard and food wastes, building construction and demolition waste and some paper) is collected as feedstocks for biofuel plants, the handling and tipping fees are likely much lower, in the \$30 per ton range.[wwwwwwwww]

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[wwwwwwwww] A much more thorough analysis of tipping fees by waste type is planned for the final rulemaking analysis.

The avoidance of tipping fees, however, is a complex issue since landfills are generally not owned by municipalities anymore. Both large and small municipalities recognized their inability to handle the new and complex solid waste regulations at a reasonable cost. Only 38 out of the 100 largest cities own their own landfills. To deal with the solid waste, large private companies built massive amounts of landfill capacity. The economic incentive is for private landfill operators to fill their landfills with garbage as early as possible to pay off their capital investment (landfill site) quickly. Also, the longer the landfill is operating the greater is its exposure to liability due to leakages and leaching. Furthermore, landfills can more cost-effectively manage the waste as the scale of the landfill is enlarged. As a result, there are fewer landfills and landfill owners, and an expansion of market share by large private waste management firms, thus decreasing the leverage a biofuel producer may have.[xxxxxxxxx] Hence, MSW-biofuel plants could be opposed by landfill operators. This may also be true in the case of a waste-to-energy (WTE) facility, which burns as much garbage as possible to produce electricity. For sustainable operation, a certain amount of daily waste supply should be guaranteed. A MSW-biofuel plant may therefore be seen as an unwelcome competition to both landfill owners and WTE facilities. This competition may increase the cost of cellulosic biomass to the biofuel producers.

Once the cellulosic biomass has been sorted from the rest of MSW, it would have to be transported to the biofuels plant. Transportation is different for MSW biomass compared to forest and crop residues. Forest and crop residues are collected from forests and farms, which are both rural sites, and transported to the biofuel plant which likely is located at a rural site. The trucks which transport the forest and crop residues are large over-the-road trucks which can average moderate speeds because of the lower amount of traffic that they experience. Conversely, MSW is collected from throughout urban areas and would have to be transported through those urban areas to the plant site. If the cellulosic biomass is being collected at curbside, it would likely be collected in more conventional refuse trucks. If the biofuel plant is nearby, then the refuse trucks could transport the cellulosic biomass directly to the plant. In this case, the refuse trucks would simply be delivering the MSW to the biofuel producer instead of a landfill or waste sorting facility, and therefore would not result in any additional cost to the biofuel producer. If, however, the plant is located far away from where the waste is collected, then the refuse trucks would probably to be offloaded to more conventional over-the-road trucks with sizable trailers to make transport more cost-effective. This would likely be an additional cost charged to the biofuel producer, as the MSW is now being transported farther to be used as a biofuel feedstock instead of disposed of at a local landfill. Because the roadside cost of MSW is significantly lower than the other feedstock sources it may still be cheaper to import MSW from some distance away rather than use an alternative, locally available feedstock.

Cellulosic biomass sourced from MSW is generated year-round. If a steady enough stream of this material is available, then secondary storage would not be necessary, thus avoiding the need to install secondary storage. We assumed that no secondary storage costs would be incurred for MSW-sourced cellulosic biomass. If the MSW is sourced from within the same county as the biofuel plant we have assumed that there is no cost to the biofuel producer for the

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[xxxxxxxxx] Osamu Sakamoto, <u>The Financial Feasibility Analysis of Municipal Solid Waste to Ethanol Conversion,</u> Michigan State University, Plan B Master Research Paper in partial fulfillment of the requirement for the degree of Master of Science, Department of Agricultural Economics, 2004 transportation of the feedstock. If, however, the feedstock comes from a county other than the one in which the biofuel plant is located we assume that the biofuel producer must pay to have the MSW transported in large over-the-road trucks. These assumptions are used for the transportation and secondary storage tool discussed in Section 1.3 and in detail in the following section.

#### 4.1.1.2.3 Transportation and Secondary Storage

For many of the feedstocks such as corn or soy oil, the feedstock costs include the cost for transportation and any storage costs. However, for cellulosic feedstocks, the FASOM model only estimates the feedstock costs at the “farm-side” or “forest side,” therefore, it was necessary to estimate the transportation and secondary storage costs for these feedstocks. These transportation and secondary storage cost estimates were ultimately used in the Cellulosic Feedstock Transportation and Storage Cost Tool described in Section 1.3. Each feedstock involves a different set of assumptions for transportation and whether or not secondary storage would be necessary.

##### Agricultural Residue and Energy Crops

For agricultural residue and energy crops (assumed to be switchgrass), we assume that for most of these feedstocks, that the feedstocks will be transported to secondary storage, stored and then transported from secondary storage to the plant. Since a portion of this feedstock may be harvested close to the plant, we assumed that some of the feedstock would be transported directly to the plant.

For transportation to secondary storage, we used the cost information in Table 4.1-14. The transportation to secondary storage involves loading a trailer with 12 tons of baled cellulosic material, and pulling the trailer to the secondary storage site using a high speed farm tractor. At the secondary storage site, the bales must be offloaded for storage. The loading and unloading of the trailer involves the use of a tele-handler. Total time for loading and unloading is estimated to require 40 minutes of time, or 20 minutes at each site.

For estimating costs, we subdivided the transportation from farm to secondary storage into two different operations. One operation is the loading and offloading of the cellulosic feedstock bales which require the use of the farm tractor, trailer and one tele-handler per tractor/trailer. To estimate these costs we summed the total per-hour costs of these three pieces of equipment (assuming one telehandler instead of two), minus the farm tractor fuel and lube costs since the farm tractor is parked, which sums to $110 per hour. Assuming that these loading and unloading operations require 40 minutes of time for 12 tons of cellulosic feedstock, we derive a cost of $6.14 per ton.

The second operation for the transportation costs to secondary storage involves the actual hauling of the agricultural residue and energy crop cellulosic feedstocks from the farm to the secondary storage site. For this operation, the farm tractor pulls the trailer containing the bales of cellulosic feedstock. We again use the total costs of the farm tractor and trailer, but include the fuel and lube costs since the farm tractor is using fuel pulling the trailer; this totals to $83 per hour. We assume that the farm tractor will average 22 miles per hour hauling the 12 tons of cellulosic feedstock to secondary storage. This results in a cost of $0.64 per ton-mile which accounts for the roundtrip from the farm to the secondary storage facility. Therefore, the total transportation costs per ton of feedstock is $6.14 + $0.64 x D where "D" is the one way distance from farm to secondary storage. Whenever we estimated the distance traveled from the farm to secondary storage, we assumed that the distance would be 1.3 times the most direct route between the two. This assumption makes sense because roads in farming regions of the country are less numerous than in urban areas, and they often require traveling in circuitous routes to reach the desired site. For example to reach a location north and west of a starting location, it may be necessary to travel due north and then due west on two different roads until the desired site is reached. Also, rural roads can be windy which also adds to the travelled distance

The secondary storage costs are accounted for in Table 4.1-15. However, an inherent assumption of that analysis is that the per-ton storage costs are the same $8.89 per ton regardless of the size of the storage facility, which is inconsistent with how construction costs are incurred. To optimize the secondary storage costs with the transportation costs, we scaled the secondary storage costs such that small secondary storage facilities would incur a higher per ton cost than a larger facility. The scaling factor we used is 0.8.[YYYYYYYYY] The base size for the secondary storage facility is 25,800 tons of cellulosic feedstock which is the size of secondary storage site which matched the costs for another secondary storage cost estimate. The costs scale up and down from the $8.89 per ton value indicated in Table 4.1-15 depending on whether the facilities are smaller or larger facilities. For example, a secondary storage facility which stores 9900 tons of cellulosic feedstock is estimated to cost $10.7 per ton of feedstock stored, while a facility which stores 132,000 tons of cellulosic feedstock is estimated to cost $6.40 per ton of feedstock stored.

Scaling the secondary storage costs was important for conducting an optimization analysis with respect to transportation and secondary storage costs. If secondary storage costs did not vary based on size, then the most efficient means for storing the cellulosic feedstock would be in very small secondary storage facilities located at the farm, which would essentially eliminate transportation costs to the secondary site. However, we feel that such an assumption would not be realistic considering how the construction costs are incurred.

In conducting our optimization analysis, we assumed that denser agricultural residue or energy crop densities would help to lower the transportation and secondary storage costs compared to less dense cellulosic feedstocks. This is logical because the higher the density, the shorter the distance that cellulosic feedstock would have transported to secondary storage facilities and the less numerous and larger the secondary storage facilities could be for the same amount of feedstock. The optimization analysis we conducted considered three different densities for the cellulosic material and these were 1.8, 5.7 and 15 tons per acre. We assumed that 25% of the acres of the land are planted in the area. We then assessed an array of distances

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[YYYYYYYYY] The capital cost is estimated using an exponential equation. The equation is as follows: $(Sb/Sa)^{e}xCa=Cb$, where Sa is the size of reference sized secondary storage site which can hold 25,800 tons of cellulosic feedstock, Sb is the size of the unit for which the cost is desired, e is the exponent, Ca is the cost of the reference secondary storage site, and Cb is the desired cost for the different sized unit. The exponential value "e" used in this equation is 0.8 for secondary storage sites (equation from Peters and Timmerhaus, 1991) from farm to secondary storage sites and secondary storage site capacities consistent with the distances. For example, for the 5.7 tons per acre crop density case, one situation we analyzed assumed that the cellulosic feedstock would be transported 7.5 miles to 10 different secondary storage sites each storing 107,000 tons of cellulosic feedstock per site. This example estimated an average transportation to secondary storage and secondary storage cost of $17.63 per ton. Another example for the 5.7 tons per acre crop density case assumed that there would be 60 secondary storage sites each storing 17,900 tons of cellulosic feedstock which would require that, on average, the cellulosic feedstock would need to be transported 3.1 miles to the secondary storage site. This example costs about the same, which is $17.60 per ton of feedstock. However, our optimization analysis estimates that the optimum situation for the 5.7 tons per acre crop density case is 23 secondary storage sites each storing 46,800 tons of cellulosic feedstock. The average transportation distance for this optimum case is 5.0 miles and the average cost for both the transportation to the secondary storage site and the secondary storage cost is $17.20 per ton of cellulosic feedstock.

When conducting this analysis, we realized that for a portion of the feedstock grown closest to the plant, that it would make more sense to build the secondary storage site at or adjacent to the plant to avoid extensive transportation costs moving the feedstock for storage when the plant was nearby. The assumption we made is that for all feedstock grown within the radius equal to the optimal transportation distance to secondary storage, the feedstock would be transported directly to the plant. For example, for the 5.7 tons per acre case, the average transportation distance to secondary storage is 5.0 miles when the costs are optimized. To avoid excessive transportation costs, we assumed that all the feedstock grown within 5.0 miles of the plant would be transported directly to the plant or to storage adjacent to the plant. This assumption for the optimized 5.7 tons per acre case resulted in 14% of the cellulosic feedstock being transported directly to the plant. As the density of the feedstock increases, this assumption resulted in a larger amount of cellulosic feedstock being transported directly to the plant.

Table 4.1-21 summarizes the optimal number and size of secondary storage sites and average transportation distances for transporting the cellulosic feedstock from the farm to the secondary storage sites, and the costs for the optimal situation for each cellulosic feedstock density case. Table 4.1-21 also summarizes our estimate of the percentage of cellulosic feedstock being transported directly to the plant.

### Table 4.1-21
### Optimal Number of Secondary Storage Sites and Optimal Transportation Distances to those Sites

| | | | |
|---|---|---|---|
| Celluosic Feedstock Density (tons/acre) | 1.8 | 5.7 | 15 |
| Average Transportation Distance (miles) | 5.66 | 4.96 | 4.36 |
| Number of Secondary Storage Sites | 60 | 23 | 11 |
| Amount of Cellulosic Feedstock per Secondary Storage Site (tons) | 19,400 | 46,800 | 88,000 |
| Cost for Storage and Transportation to Secondary Storage Site ($/ton) | 19.17 | 17.20 | 15.88 |
| Percentage of Cellulosic Transported directly to the Plant | 7 | 14 | 23 |
| Average Cost including Storage and Transportation to Secondary Storage Site ($/ton) | 17.83 | 14.81 | 12.30 |

Our transportation and secondary storage optimization analysis shows that as crop density decreases, there is a corresponding increase in the secondary storage costs and the transportation costs for transporting the cellulosic feedstock from the farm to secondary storage. Low crop density requires an increased number of smaller secondary storage sites, however smaller secondary storage sites are associated with higher per-ton costs. Another advantage of higher density feedstocks is it becomes more likely that more of the cellulosic feedstocks will be taken directly to the plant as opposed to being stored at secondary storage sites, which further helps to reduce the feedstock costs.

For integrating the secondary storage costs and the transportation costs into our model described in Section 1.3, we needed to represent these costs in a form that could be used by the model. Since our model contains crop density information for each crop, we conducted a linear regression of the cellulosic feedstock density values against the average secondary storage cost and transportation to secondary storage costs (bottom row of Table 4.1-21). This regression resulted in the following equation: SSTC = -0.473 x DY +18.90 where “SSTC” equals the secondary storage cost and transportation cost from the farm to secondary storage and “DY” equals the cellulosic feedstock density in the farm field in tons per acre.

Once the cellulosic feedstock is at a secondary storage facility, it must be transported from secondary storage to the plant. This additional transportation step will incur an additional cost. To estimate this transportation cost we used the cost information in Table 4.1-16.

To facilitate these calculations we once again subdivided the cost estimate into two different operations. One operation is the loading and offloading of the cellulosic feedstock bales. For the loading operation, we assumed the use of the truck, flatbed trailer and two tele-handlers. We assumed that two tele-handlers would be used to optimize the time required for loading of 24 tons of cellulosic feedstock. To estimate these costs we summed the total per-hour costs of these three pieces of equipment, minus the truck fuel and lube costs because the truck is parked (using one-eleventh of the costs for 22 tele-handlers), which sums to $109 per hour. We assume that the actual loading operation would require about 30 minutes. However, the over-the-road truck would likely require that a tarp be secured over the bales to as a safety measure for hauling the bales over principal roadways, so we increased the loading time to an hour. For offloading the feedstock, we assumed that the plant would have its own offloading equipment, so we only included the total cost minus fuel and lube for the truck and trailer, which is $25.03 per ton. However, because the truck would also have to be weighed for determining the mass of feedstock being delivered, we increased the total offloading time including weighing of the cellulosic feedstock to 1 ½ hours. Totaling the loading and offloading costs for 24 tons of cellulosic feedstock, we derive a cost of $6.90 per ton.

The second operation is the actual hauling of the cellulosic feedstock from secondary storage to the plant. For this operation, the truck pulls the flatbed trailer containing the bales of cellulosic feedstock. We used the total costs of the truck and flatbed trailer, but include the fuel and lube costs since the truck is pulling the trailer; this totals to $69 per hour. We assume that the truck will average 30 miles per hour hauling the 24 tons of cellulosic feedstock to the plant. Although the over-the-road is capable of much higher speeds compared to the farm tractor which hauled the feedstock to the secondary storage, we assumed that the truck's speed would be limited by driving on dirt roads and smaller county roads and by needing to drive through smaller towns located in rural areas. This results in a cost of $0.17 per ton-mile which accounts for the roundtrip from the secondary storage facility to the plant. Therefore, the total transportation costs per ton of feedstock can be summarized into the following equation: TC = $6.90 + $0.17 x D where "TC" is transportation cost in dollars per ton and "D" is the one-way distance in miles.

We needed to estimate an average distance traveled for the cellulosic feedstock when it is being transported from secondary storage to the plant. The average distance can be estimated by knowing the size of the area from which the cellulosic feedstock is being harvested, such as the entire county. The average distance from each point within the area to the centerpoint of the area (the cellulosic biofuel plant is assumed to be located in the center of the country) is estimated to be 70 percent of the total radius or distance to the outer edge of the area. Another way to understand the 70 percent value, assuming that the area is a circle, is that half the area of the circle is within the area marked by 70% of the circle's total radius while the other half of the radius falls within the last 30% of the circle's radius. This same relationship holds true for a square as well. Therefore, knowing the area of the region from which the cellulosic feedstock is being harvested for processing by a particular plant, we assumed that the average transportation distance is 70% of the total average distance from the centerpoint to the outer edge of the area.

### Forest Residue and Municipal Solid Waste

By the nature of how they are produced, MSW and forest residue were assumed to not need secondary storage. MSW is created throughout the year and can be processed and then transported directly to the plant as it is produced. This is true for forest residue as well. Forest material is "stored on the stump" until it is needed. Since the primary uses of forest material is for pulp and paper production and wood products for the building industry, and these uses demand product year-round, the forest residue from these operations are assumed to be made available on the year-round basis as well. Thus for these categories of cellulosic feedstocks, only transportation directly to the plant was assumed.

Another factor that we considered is that MSW already incurs a transportation cost for transporting the MSW to a landfill.  Thus, when MSW is being transported to a cellulosic biofuel plant, instead of additional transportation cost being incurred, the MSW would simply be rerouted to a cellulosic biofuel plant and no new transportation cost would be incurred.  This assumes that the MSW has been partially or perhaps completely presorted such that the MSW feedstock would simply be rerouted to the cellulosic biofuel plant.  However, if sorting still needs to occur, it very well would occur at the landfill and additional transportation costs would be incurred if the cellulosic biofuel plant is not located at the landfill.  If the MSW is being transported to a plant located away from the landfill, for example, if the plant were to be located in an adjacent county, then additional transportation costs would be incurred.

For estimating the transportation costs for MSW and forest residue we assumed that the transportation cost methodology for transporting cellulosic feedstock from secondary storage to the cellulosic biofuel plant would apply in this case as well.  Thus, the transportation costs per ton of feedstock for forest residue and for intercounty shipments of MSW would be TC = \$6.90 + \$0.17 x D where "TC" is transportation cost in dollars per ton and "D" is the one-way distance in miles.

#### 4.1.1.2.4  Cellulosic Ethanol Production Costs

Two different technologies served as the basis for estimating the costs for converting cellulose into ethanol.  One technology relies on the biochemical conversion of the cellulose to ethanol.  The second technology converts the cellulose to a syngas and then reacts the syngas to mixed alcohols over a catalyst.

*Biochemical Conversion of Cellulose to Ethanol*

We contracted with the National Renewable Energy Laboratory (NREL) to estimate the cost to convert corn stover into ethanol for the years 2010, 2015, and 2022.  It is of particular importance for the following discussion, to note the following: NREL used the same feedstock mass (772,168 dry tons of corn stover) in all three cases.

For the three cases, NREL assumed the feedstock, 'as-needed,' was hauled to the plant by trucks and trailers from satellite storage, already shredded to the appropriate size for processing, and free of dirt, iron, and other contaminates; in other words – process ready.  The transport vehicles were unloaded into surge tanks, large enough to hold feedstock for three days of operation.  The pretreatment and hydrolysis reactors are charged from these feed surge tanks.

The following is background information for our discussion of both operating and capital costs, some of which is also included in our brief discussion of the process flow description and capital equipment charges.  The first step was to develop a set of process flow diagrams that set the arrangement of the equipment.  Based on the desired production volume, these diagrams, were used within an ASPEN Plus4© model to develop complete mass and energy balance. The model consists of 164 unit operation blocks, 457 streams (247 material and 210 heat or work), 63 components, and 82 control blocks.

The overall model is thermodynamically rigorous and uses physical properties for the feedstock and process chemicals included in the ASPEN software as well as property data developed at NREL. The individual unit models are also thermodynamically consistent and can be either rigorous (for example, the simulation of the distillation) or simple. The reactors could be modeled with kinetic expressions, but because of the level of development of the experimental data, they were modeled as experimentally determined conversions of specific reactions. This type of model still satisfies the rigorous mass and energy balance. Other unit operations, such as liquid-solid separations, are typically modeled with fixed solids removal and liquid retention (in the solids stream) data from vendor tests.[zzzzzzzzz] Using the process flow diagrams and the mass and energy balance information, NREL estimated stream flows and conditions, along with the estimated quantities of raw materials and other process chemicals.

The following table presents NREL's summary of each of the three year's total project investment. For each year's total project investment, NREL provided capital charge, which includes income tax, depreciation, and average return on investment, the cost of raw materials, waste handling charges, and by-product credits.

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[zzzzzzzzz] A. Aden, M. Ruth, K. Ibsen, J. Jechura, K. Neeves, J. Sheehan, and B. Wallace
National Renewable Energy Laboratory (NREL); L. Montague, A. Slayton, and J. Lukas Harris Group, Seattle, Washington, Ethanol Process Design and Economics Utilizing Co-Current Dilute Acid Prehydrolysis and Enzymatic Hydrolysis for Corn Stover; June 2002; NREL is a U.S. Department of Energy Laboratory Operated by Midwest Research Institute • Battelle • Bechtel; Contract No. DE-AC36-99-GO10337

Table 4.1-22. Summary of NREL's Capital Charges and Operating Costs

| Year Technology | 2010 | | 2015 | | 2022 | |
|---|---|---|---|---|---|---|
| Plant Size MMgal/yr | 56 | | 69 | | 71 | |
| Capital Cost $MM (TPI) | 232 | | 220 | | 199 | |
| | $MM/yr | ¢/gal | $MM/yr | ¢/gal | $MM/yr | ¢/gal |
| Capital Charge 10% after tax ROI | 42 | 75 | 39 | 56 | 35 | 50 |
| Fixed Costs | 9 | 16 | 9 | 12 | 8 | 12 |
| Feedstock Cost | 84 | 46 | 51 | 35 | 50 | 35 |
| Other Raw Matl. Costs | 17 | 30 | 4 | 5 | 16 | 16 |
| Enzyme Cost | 18 | 32 | 7 | 10 | 5 | 8 |
| Enzyme Nutrients | 8 | 14 | 2 | 3 | 2 | 2 |
| Electricity | -6 | -10 | -7 | -9 | -12 | -16 |
| Waste Disposal | 1 | 2 | 3 | 4 | 1 | 1 |
| Total Costs | 173 | 205 | 108 | 116 | 105 | 108 |

The quantities of all raw material, generated electricity, and produced wastes were determined using the ASPEN mass and energy balance model. These costs include: *Feedstock* – corn stover, *CSL* – purchased corn steep liquor (a nutrient); *Cellulase* – purchased cellulase enzymes; *Other Raw Materials* – sulfuric acid, diammonium phosphate, make-up water, boiler feed water chemicals, cooling water chemicals. Waste Disposal – waste water chemicals, waste water polymers, ash disposal, gypsum disposal. *Electricity* – marketing and distribution of surplus electricity to the grid for credit.

We note that the percent change in total project investment from year to year is not insignificant and reflects improvements in mechanical process efficiencies among other general improvements in the process technology, including the automatic distributed process control system, all of which are off-set to some extent by increases in the real cost of the technology improvements, as well as those of constructions materials. We discuss capital costs following this discussion of operating costs.

The most notable reductions in NREL's operating costs are in the price per dry ton of the corn stover feedstock and in the cost of cellulase enzyme. NREL anticipates significant improvement in the efficiency of these enzymes, especially those that saccharify glucan to glucose and xylose oligomers[AAAAAAAAAA] generated during hydrolysis. They also expect improvement in the yeasts that ferment xylose. According to the 2007 NREL – State of Technology report, they anticipate that as a first step, the relationship between corn stover hydrolysate conditioning and fermentation will be better defined and understood. Commercial cellulase preparations will continue to be analyzed for baseline performance (specific activity), and due to increased research efforts, cellulase function will be better understood, which should lead to efficiency improvements. Integrated testing of whole slurry and recycle options will also be conducted resulting in potential improvements in that area. Last, the efficacy of advanced enzyme preparations (including oligomerases and/or hemicellulases) will continue to be tested in conjunction with alternative pretreatment technologies. NREL expects that the cost of pretreatment will deminish, hydrolysis time will decrease, and the sugar (xylose and glucose) yields will increase.[BBBBBBBBBB]

As the process costs decline over time, the feedstock costs become a larger fraction of the overall costs. We also note that in the following table that the cost of the feedstock makes up 50% of the total cost in 2010; 67% in 2015; and 68% in 2022. The reduction in feedstock cost, from $60 per dry ton in 2010, to $45.90 per dry ton in both 2015 and 2022 also has a significant effect on operating costs. In addition, NREL did not include payments to the farmers/growers nor for soil nutrients (fertilizer, etc.) that were removed with the harvested corn stover. The cost of the cellulase enzyme is the next highest contributor, with percent reductions contributed to total cost that reduced from ~19% in 2010, to 13% in 2015 and 10% in 2022. It should be obvious that any reductions in these costs have significant effects on the total operating cost. The majority of research going forward will be focused on these two items, although some work will be done to reduce the cost of the others. Table 4.1-23 summarizes NREL's operating costs for a biochemical cellulosic ethanol plant.

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[AAAAAAAAAA] Xylan polymer chains, with considerably fewer residue numbers in the chain than were in the original xylan polymer; they were broken off the polymer as these short chains rather than as single molecule sugars.

[BBBBBBBBBB] Andy Aden, National Renewable Energy Laboratory, Golden, Colorado, Biochemical Production of Ethanol from Corn Stover: 2007 State of Technology Model, Technical Report NREL/TP-510-43205, Task No. BB07.2410; May 2008

**Table 4.1-23.**
**Percent of the total operating cost for each actual operating cost item**

| | 2010 | | 2015 | | 2022 | |
|---|---|---|---|---|---|---|
| | ¢/gal | % of Total | ¢/gal | % of Total | ¢/gal | % of Total |
| Feedstock | 84 | 50 | 51 | 67 | 50 | 68 |
| Biomass to Boiler | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| CSL[a] | 14 | 8 | 3 | 4 | 2 | 3 |
| Cellulase | 32 | 19 | 9 | 13 | 8 | 10 |
| Other Raw Matl. Costs | 31 | 18 | 5 | 7 | 16 | 22 |
| Waste Disposal | 2 | 1 | 4 | 5 | 2 | 2 |
| Electricity | -10 | -6 | -9 | -12 | -16 | -22 |
| Fixed Costs | 16 | 10 | 12 | 16 | 12 | 16 |
| | 168 | | 76 | | 72 | |

[a] Corn steep liquor – provides nutrients for the enzymes.

The following table includes our adjustments to NREL's variable or operating cost data for the three years studied. We note that the two main differences between NREL's and our estimates are in the feedstock costs and in the way we calculate capital charges. We adjusted NREL's capital charges which were calculated using a 10% after tax return on investment, to reflect a 7 percent before tax rate of return, which is the capital cost basis for our cost analyses. We also adjusted the NREL feedstock costs to those that we estimated in Table 4.1-6, which was $67.42 per dry ton. This significant difference between their and our feedstock cost estimates is due to our including payments to farmers/growers plus covering the cost to replace nutrients (fertilizer, etc.) removed at the time the stover was harvested. According to a personal communication, NREL used unpublished data from the Idaho National Laboratory that indicate feedstock costs will be significantly reduced between 2010 and 2015.

**Table 4.1-24.**
**Adjusted Capital Charges and Operating Costs**

| Year<br>Technology | 2010 | | 2015 | | 2022 | |
|---|---|---|---|---|---|---|
| Plant Size MMgal/yr | 56 | | 69 | | 71 | |
| Capital Cost $MM | 232 | | 220 | | 199 | |
| | $MM/yr | ¢/gal | $MM/yr | ¢/gal | $MM/yr | ¢/gal |
| Capital Cost 7% ROI before taxes | 25 | 46 | 24 | 35 | 22 | 31 |
| Fixed Costs | 9 | 16 | 9 | 12 | 8 | 12 |
| Feedstock Cost | 52 | 94 | 55 | 75 | 52 | 73 |
| Other Raw Matl. Costs | 17 | 30 | 4 | 5 | 16 | 16 |
| Enzyme Cost | 18 | 32 | 7 | 10 | 5 | 8 |
| Enzyme Nutrients | 8 | 14 | 2 | 3 | 2 | 2 |
| Electricity | -6 | -10 | -7 | -9 | -12 | -16 |
| Waste Disposal | 1 | 2 | 3 | 4 | 1 | 1 |
| Total Costs | 124 | 224 | 94 | 135 | 90 | 127 |

The changes in the minimum ethanol selling prices for the three years studied are partially due to the changes in necessary capital investments. In order to determine capital costs, NREL developed specifications for pieces of equipment that fall within different areas of a biochemical plant. A biochemical plant is divided up into 8 different areas (Area 200 through Area 900). For each equipment specification, they developed individual purchased equipment and installation costs. Vendors supplied installation costs where possible; in other cases installation factors were used. Equipment costs were obtained from vendor quotations when possible, especially for uncommon equipment such as pretreatment reactors. These costs reflect the base case for which the equipment was designed. If process changes were made and the equipment size changed, the equipment is not generally re-costed, in detail. Rather, the cost was adjusted by scaling using the following exponential scaling expression, [New Cost = Original Cost x (New Size/Original Size)^exp]. They also scaled the size of equipment that was known to change linearly with a change in inlet flow. The scaling exponents (exp) were obtained from vendor quotes, or from a standard reference, such as Garrett.[CCCCCCCCCC]

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[CCCCCCCCCC] Garrett, D.E., Chemical Engineering Economics, Van Nostrand Reinhold, New York, 1989

Installation costs were taken primarily from Delta-T, a process consultant's experience. Once the scaled, installed equipment costs (total installed capital costs) were determined, they applied overhead and contingency factors to determine a total plant investment cost. That cost, along with the plant operating expenses (generally developed from the ASPEN model) was used in a discounted cash flow analysis to determine the cost of ethanol production, using a set discount rate. NREL use a discount rate of 10%, whereas we used 7%, a factor generally used in our financial calculations. For this analysis, the minimum ethanol selling price was the primary value used to compare cases.

The total project investment was briefly discussed previously in our summary discussion of operating costs; we used NREL's total project investment for our estimates. The following summarizes the capital expenditures that account for that capital investment.

Area 200: Pretreatment and Hydrolysis. The equipment in this area consists of an assortment of pipe, pumps, tanks, tank-agitators, tank-mixers, coolers, 3-pneumapress filters, as well as three separate process trains, each of which includes a presteamer, a blow tank, and a reactor. The presteamer uses low-pressure steam to heat the feedstock to about 212 $^{o}$F. It discharges the hot, saturated mix into a blow tank that serves as a seal between the presteamer and the hydrolysis reactor. The mix is charged to the reactor and dilute sulfuric acid is added; the reactor operates at 191 psia and 547 $^{o}$F. Most of the hemicellulose, e.g., primarily xylose, mannose, arabinose, and galactose are converted into sugars. Glucan in the hemicellulose and a small portion of the glucan in the cellulose are converted to glucose. These conditions also solubilize some of the lignin in the feedstock and 'expose' the cellulose for subsequent enzymatic hydrolysis, in a downstream section. In addition, acetic acid is liberated from the hemicellulose hydrolysis. Degradation products of pentose sugars (primarily furfural) and hexose sugars (primarily hydroxymethyl furfural (HMF)) are also formed.

Following the pretreatment reactor, the hydrolyzate liquid and solids are flash cooled, which vaporizes a large amount of water, a portion of the acetic acid, and much of the furfural and HMF, which can be toxic to downstream fermentation microorganisms.

In addition to the flash removal of aldehydes, the solids are washed and filter-pressed to remove the liquid portion of the hydrolyzate, which contains sulfuric acid. The liquid is then neutralized to pH 10 with ammonia and held until the gypsum precipitates and is filtered out. The hydrolyzate, which contains the hydrolyzed xylose sugars and some glucose sugars, is mixed back with dilution water and the filter cake, which contains the unhydrolyzed cellulose and is sent to saccharification and co-fermentation (Area 300)

An important issue on an industrial scale is accurate pH control. By pH 11, as much as 30% of the glucose may be lost to HMF and other side reactions. Several factors increase the probability of overshooting pH endpoints during neutralization. The natural buffering capacity of hydrolyzates causes neutralization reactions to be slow. Plus, measurements using pH membrane probes are affected by temperature and the presence of dissolved organic compounds (sugars and lignin).

Since we are handling the same mass of feedstock in each of the modeled years, we don't expect the cost of the equipment for pretreatment and hydrolysis will change much over the 2010-2022 time period. The equipment costs for Area 200 – Pretreatment & Hydrolysis are 2010: $23-million; 2015: $22.7-million; and 2022: $18.9-million. Neutralization and Conditioning costs were separated out from the Pretreatment & Hydrolysis costs, even though the NREL's design report includes both cost centers in Area 200. Neutralization and Conditioning costs are as follows: 2010: $8.4-million; 2015: $9.4-million; and 2022: $7.7-million. The combined cost for Area 200 is as follows: 2010: $31.4-million; 2015: $32.1-million; and 2022: $26.6-million. In total, this area contributed about 23.5% to the total installed capital cost of the project in 2010; about 25.3% in 2015; and 23.2% in 2022

Area 300: Saccharification and Co-Fermentation. The equipment in this area consists of pumps, tanks, tank-agitators, coolers, and heaters. Two different operations take place in this process area — the saccharification of the cellulose to glucose using cellulase enzymes, and the fermentation to ethanol of that glucose plus the xylose and glucose sugars from the dilute acid pretreatment of hemicellulose from Area 200.

Glucan from the cellulose undergoes hydrolysis or saccharification, at about 149 $^{o}$F, prior to fermentation. This slightly higher temperature increases enzyme activity and reduces the time and amount of enzyme required for saccharification. Saccharification or cellulase enzymes, purchased from an enzyme manufacturer, and the diluted, detoxified hydrolyzate are continuously added to a train of five 1-million gallon saccharification vessels; residence time is estimated to be 36-hours.

Cellulase enzyme is actually a 'cocktail' of enzymes, comprised of: (1) endoglucanases, which attack randomly along the cellulose fiber to reduce polymer size rapidly; (2) exoglucanases, which attack the ends of cellulose fibers, allowing it to hydrolyze highly crystalline cellulose; and (3) β-glucosidase, which hydrolyzes cellobiose to glucose. Several bacteria and fungi naturally produce these enzymes, including bacteria in ruminant and termite guts and white rot fungus. The most common organism used to produce cellulase industrially is *Trichoderma reesei*. Genencor International and Novozymes Biotech are developing more cost effective cellulase enzymes. DOE is funding this important work, which should improve the economic viability of biomass conversion.

The recombinant *Z. mobilis bacterium* is used as the biocatalyst to ferment glucoses and xyloses to ethanol. Several research institutions are genetically engineering strains, such as *Z. mobilis,* to treat additional sugars and identifying other naturally occurring organisms that metabolize hemicellulosic sugars.

The *Z. mobilis* must be 'grown' in increasingly higher volume stages. Initially, a small amount of saccharified slurry and nutrients are combined in a very small vessel with a seed inoculum, that's been grown in the laboratory. This initial seed batch is used as the inoculum for the next larger size seed batch, and so on. This series of batch scale-ups continues until the last batch is large enough to support the actual production fermentation.

Finally, the seed inoculum, nutrients (corn steep liquor) & (diammonium phosphate – a source of nitrogen for the yeast), and saccharified slurry are cooled to about 106 $^{o}$F and added to a train of five 1-million gallon continuous fermentors. At this point, the process actually becomes a simultaneous saccharification and co-fermentation (SSCF) process. Even though the temperature in the fermentation tanks has been reduced to account for the ethanologen's intolerance to heat, the enzymes do continue to hydrolyze cellulose, albeit at a slightly reduced rate. The main byproduct, produced during fermentation is carbon dioxide ($CO_2$), which is removed in a later process stage. The ethanol broth called 'beer' is collected in a storage tank, called a beer well, before it's pumped to distillation.

NREL anticipates significant capital savings for saccharification and co-fermentation between 2010 and 2015, with fewer between 2015 and 2022. We note that this area contributed 15.4% to the total installed capital cost in 2010, but only 8.8% in 2015 and 8.8% in 2022. The equipment costs for Area 300 – Saccharification and Fermentation are 2010: $20.5-million; 2015: $11.2-million; and 2022: $10.1-million.

Area 400 – In earlier studies, NREL included plans to produce enzymes in Area 400. For the current studies, Area 400 has been removed and enzymes will be purchased and grown on site under licensing agreements with enzyme suppliers.

Area 500 – Product, Solids, and Water Recovery (Distillation, Dehydration, Evaporation, and Solid-Liquid Separation). The equipment in this area includes distillation and rectification columns, pumps, condensers and coolers, pumps, pipe, filter-presses, and evaporators.

Beer, from the beer well in Area 300, is preheated and fed to a distillation column. The column overhead containing all the $CO_2$ and about 0.2% of the ethanol and a small quantity of water is sent to a scrubber, which recovers and recycles about 99% of the vented ethanol. In the tower bottoms, about 90% of the water has been removed and it contains approximately 0.7% of the total volume of ethanol fed to the tower. Over 99% of the total ethanol fed to the tower is removed as a 39.4% w/w mixture with water vapor through a side draw and fed directly to a rectification column for further ethanol enrichment. We discuss the distillation column bottoms in the evaporation and solid-liquid separation section of this area.

The rectification tower operating conditions are set to produce an overhead 92.5% w/w ethanol/water saturated vapor mixture. The tower bottoms are a 0.05% w/w ethanol/water mixture. In fact, only 0.1% of the total ethanol from the fermentation area is lost to the bottoms.

The rectification column overhead is superheated and fed to one of two adsorption columns in a molecular sieve adsorption unit. The two columns operate alternately; while one bed is operated to remove water from the ethanol, the other is regenerated by passing a very small slipstream of pure ethanol vapor back through the loaded bed that strips the water off the adsorbent, while the column is under a vacuum. The mixture is condensed and returned to the rectification column feed stream. The adsorption column removes 95% of the water and a small quantity of ethanol. The 99.5% pure ethanol vapor is condensed, cooled, and pumped to storage.

Evaporation, and Solid-Liquid Separation: The beer column bottoms, with about 5.8% insoluble solids, are fed to the first effect evaporator, where 24% of the water in the feed is evaporated. The evaporator bottom slurry, cooled from ~243 $^{o}$F to ~189 $^{o}$F, is sent to a filter-press, from which the filtrate is returned to the second evaporator effect; the filter cake is not washed. In the second effect evaporator, 44% of the feed water is evaporated. The third effect evaporates 76% of the remaining water. The final vapor is condensed and fed to a condensate drum. Of the total feed to the evaporation/separation system, 10.5% remains as syrup, 11.5% is removed as a wet cake in the pressure filter, 17% is recycled back to the process as recycle water, and 61% is evaporated. The syrup from the third evaporator bottoms is 60% water, e.g., the maximum dissolved solids level that can be achieved without rapid fouling of the evaporator; the flow of very low-pressure steam to the evaporator is set to achieve this level. This syrup is mixed with the cake from the filter-press and sent to the combustor for disposal. Air from the filter-press is used for combustion air.

The equipment costs for Area 500 – Product, Solids, and Water Recovery (Distillation, Dehydration, Evaporation, and Solid-Liquid Separation) are for 2010: $23.4-million; 2015: $26.1-million; and 2022: $23.3-million. This area's contribution to the total installed capital cost in 2010 is 17.5%; in 2015, 20.6%; and in 2022, 20.3%. We believe that some of the increase from 2010 to 2015 has to do with the increased liquid flow due to the conversion improvements; larger pipe, pumps, tanks, etc may be necessary to handle the increased flow. The changes from 2015 to 2022 are not that significant, as reflected by the percent contribution of the area to total installed equipment cost.

Area 600 – Wastewater Treatment: The equipment in Area 600 consists mainly of aerobic and anaerobic digesters, digester agitators, tanks (basins), a biogas emergency flare, coolers, and pumps. The main purpose of the wastewater treatment section is to reduce the plant makeup water requirement by recovering, treating and recycling as much process water as possible. The feed to the wastewater treatment section consists of: condensed pretreatment flash vapor, condensate from the hydrolyzate filter-press vent, boiler blowdown, cooling tower blowdown, clean-in-place waste, and the non-recycled evaporator condensate. Rain and snow run-off, equipment washing, and other non-process wastewater are assumed to flow to the municipal wastewater treatment system. The stream is screened to remove large waste particles that are sent to a landfill; any remaining organic matter is anaerobically and aerobically digested. Anaerobic digestion produces a methane rich (75%-methane, 25%-carbon dioxide) biogas that's fed to the combustor. Aerobic digestion produces relatively clean water that's recycled back to the process and sludge that's burned in the combustor.

NREL didn't expect much change over the 2010 to 2022 time period. In 2010 the installed capital cost for this area was $3.4-million; in 2015, $3.7-million; and in 2022 it was 3.1-million. As important as this area is to the entire operation its contribution to the total project installed capital cost is relatively minor. In 2010 the contribution was 2.5%; in 2015, 2.9%; and in 2022 it was 2.7%.

Area 700: Bulk Storage of Chemicals. This section of the plant stors chemicals in bulk for the process and for finished, fuel-grade ethanol. The feedstock feed surge tanks we discussed just prior to the discussion of Area 200 are not included in this area. Process chemicals stored in this area include: corn steep liquor (a nutrient), sulfuric acid, cellulase enzyme, gasoline (used as a denaturant finish the fuel grade ethanol), and water for fire suppression.

There are approximately five-days of SS316-stainless steel[DDDDDDDDDD] tank sulfuric acid storage. Corn steep liquor (CSL), a nutrient for fermentation seed growth and ethanol production, also has about five-days of SS304-stainless steel[EEEEEEEEEE] storage; NREL expects the plant will require about three-25,000 gallon rail cars of CSL every three-days. There are seven-days of storage for diammonium phosphate (DAP), delivered as pellets via rail car. Appropriate quantities of CSL and DAP are mixed in a day-tank and used in Area 300 for fermentation seed production and ethanol production. A producer that supplies cellulase enzymes is expected to set up an enzyme production operation either on site or on a nearby location. Liquid enzyme storage is set for four-days in SS304 stainless steel tanks. The carbon steel fire-fighting water storage tanks provide about four-hours of operating time; the firewater pump delivers 2,500 gpm. Other pumps are sized per process requirements

There are seven-days of ethanol product storage in two 600,000 gallon carbon steel tanks. Five percent gasoline (v/v), a denaturant, is added to the ethanol as it's loaded for shipment to customers. The pumps in this section are generally sized to load a 10,000 gallon truck and trailer in about 15 min. to 20 min. maximum filling time. They can also be used to fill process day tanks.

The installed capital costs for bulk storage are, for 2010, \$3.8-million; for 2015, \$2.4-million; and for 2022, \$2.4-million. The contribution to total project installed capital costs are, for 2010, 2.8%; for 2015, 1.9%; and for 2022, 2.1%.

Area 800: Combustor, Boiler, and Turbogenerator. The purpose of the combustor, boiler, and turbogenerator is to burn various by-product or waste streams to produce steam and to generate electricity. All of the feedstock lignin and some of the cellulose and hemicellulose are not hydrolyzed in Area 300.

As previously discussed, a high soluble, solids syrup is generated in Area 600 and anaerobic and aerobic digestion of the remaining wastewater produced biogas and a small quantity of biomass sludge which are burned to generate steam and produce electricity. This contributes to over-all plant energy self-sufficiency, reduces solid waste disposal costs, and generates additional revenue through sales of excess electricity. Because of heightened interest in using biomass, pulping wastes, and sewage sludge in place of fossil fuels, new methods are being developed to handle higher moisture feeds. Traditional methods include blending the wet feed with dry material or adding auxiliary fuel to maintain the combustion temperature. When the dry solids from the filter-press cake are combined with the high soluble, solids syrup, it helps

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[DDDDDDDDDD] SS316 is an improved version of SS304, with the addition of molybdenum and a slightly higher nickel content. The resultant composition of 316 gives it much increased corrosion resistance in many aggressive environments. The molybdenum makes the steel more resistant to pitting and crevice corrosion in chloride-contaminated media, sea water and acid vapors.

[EEEEEEEEEE] SS304-stainless steel is the most versatile and the most widely used of all stainless steels. Its chemical composition, mechanical properties, weldability and corrosion/oxidation resistance provide the best all-round performance stainless steel at relatively low cost.

ensure a stable combustion bed temperature and improved boiler efficiency. In these studies NREL used a circulating fluidized bed combustor that is suitable for varying feeds and feed characteristics; however, this flexibility makes the unit more expensive than a grate or pile combustor. A Lower Heating Value (LHV) of 2,000-2,500 BTU/lb is considered the minimum for maintaining combustion.[FFFFFFFFFF] The combined feed to the combustor has a LHV of 4,179 Btu/lb. Thus, the total higher-heating value energy of the combined feed streams to the combustor is 706 MMBtu/hr. The solids contribute 59% of this energy and the syrup contributes 37%. A baghouse removes particulates from the combustion flue gas after it preheats the incoming combustion air and before it's discharged through the stack.

The boiler feed water (BFW) system includes a softener for makeup and condensate water, a deaerator to remove air and other non-condensables, surge tanks and pumps. The amount of water pretreatment necessary depends on the incoming water quality, metallurgy of the boiler, and the ratio of makeup to condensate in the feed water. Pretreatment chemicals for pH control, scale removal, and oxygen removal are added. Treated well water used for makeup and condensate are softened, deaerated, preheated and mixed to provide BFW that's converted to steam that's superheated to 950 $^{o}$F at 1,265 psia at the rate of 407,420 lb/hr. Support equipment includes BFW pumps, deaerator, automatic water pretreatment chemical injection, and condensate gathered from the various heat exchangers in the process. Boiler efficiency, the percentage of the feed heat converted to steam heat, is estimated to be 68%. Boiler blowdown is 3% of steam production. The turbine efficiency was estimated to be 85%.

The turbogenerator consisting of a multistage turbine with extraction ports, a generator, and condenser is used to generate electricity. After high pressure steam drives the multistage turbines, it is extracted at three different conditions for injection into the pretreatment reactor and heat exchange in distillation and evaporation. Twenty-eight percent of the steam is extracted from the turbine at 191 psia and 514°F, 60% at 65 psia and 327°F, and 3% at 25 psia and 239°F for process needs, as described. The remaining steam (9%) is condensed at 1.5 psia with cooling water and returned to the BFW system. For this design, a total of 30.4 megawatts (MW) of power is generated from the system. The process uses 11.7 MW, leaving 18.7 MW that is sold to the grid.

The installed capital cost for Area 800 are, for 2010, \$45.5-million; for 2015, \$46-million; and for 2022, \$43.3-million. This area's contribution to the total installed capital cost is, for 2010, 34.1%; for 2015, 36.2%; and for 2022, 37.7%.

Area 900: Utilities. All utilities, except steam and electricity, necessary for the production of ethanol are accounted for in this area. The utilities provided include cooling water, chilled water, plant and instrument air, process water, and the clean-in-place (CIP) system. No chilled water is used in the plant; the required process temperatures can be achieved by cooling water year-round.

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[FFFFFFFFFF] Steam and Electricity Generation Options For the Biomass-To-Ethanol Process, NREL Subcontract ACO-8-18019-01, Reaction Engineering International, Salt Lake City, UT, March 16, 1998. http://www.ott.doe.gov/biofuels/process_engineering.html

The plant and instrument air systems provide compressed air for air-driven equipment, instrument operation, for clean up, and the filter-press units in the post-distillation dewatering. The process water system mixes fresh well water with treated wastewater and provides water at a constant pressure to the facility. Water is provided to seed production, boiler feed water, cooling tower make-up, the CIP system, and the scrubber. It is also mixed with recycle water for dilution before saccharification. Process water is also used throughout the facility for cleaning on an as-needed basis. The CIP system provides a solution that can be heated and includes cleaning and sterilization chemicals to saccharification and co-fermentation, seed vessels, and the distillation system.

The installed capital costs for the utilities area are, for 2010, $5.6-million; for 2015, $5.5-million; and for 2022, $6.1-million. This area's contribution to the total project installed equipment costs are, for 2010, 4.2%; for 2015, 4.3%; and for 2022, 5.3%.

Table 4.1-25 summarizes the total projected capital costs for a biochemical cellulosic ethanol plant for the years 2010, 2015 and 2022.

**Table 4.1-25.**
**Projected Capital Costs for a Biochemical Cellulosic Ethanol Plant**
**($million/yr)**

| | 2010 | 2015 | 2022 |
|---|---|---|---|
| Total Capital Investment | 133.5 | 127 | 114.8 |
| Added Costs* | 98.2 | 93.1 | 83.8 |
| Total Project Investment | 231.7 | 220.1 | 198.6 |

*Added costs include the following:

Warehouse: This is estimated to be 1.5% of total installed cost

Site Development: This includes fencing, curbing, parking, lot, roads, well drainage, rail system, soil borings, and general paving. This factor allows for minimum site development assuming a clear site, with no unusual problems such as right-of-way, difficult land clearing, or unusual environmental problems, usually calculated as 9% of the installed cost of process equipment.

Prorateable Costs: This includes fringe benefits, burdens, and insurance of the construction contractor, usually calculated as 10% of total installed cost.

Field Expenses: This includes consumables, small tool equip. rental, field services, temporary construction facilities, and field construction supervision, usually calculated as 10% of total installed cost.

Home Office and Const.: This includes engineering plus incidentals, purchasing, and construction, usually calculated as 25% of total installed cost.

Project Contingency: These costs are small because of the detail included in the process design usually calculated as 3% of total installed cost.

Other Costs: This includes start-up and commissioning costs; land, rights-of-way, permits, surveys, and fees; piling, soil compaction/dewatering, unusual foundations; sales, use, and other taxes; freight, insurance in transit and import duties on equipment, piping, steel, instrumentation, etc.; overtime pay during construction; field insurance; project team; transportation equipment, bulk shipping containers, plant vehicles, etc.; escalation or inflation of costs over time; interest on construction loan. These other costs are usually calculated as 10% of total capital investment.

The costs for cellulosic ethanol produced biochemically could be lower if not all the water would have to be removed from the ethanol. Separating the water from ethanol is costly because water forms an azeotrope with ethanol. Removing the last of the water above the azeotrope requires additional capital and operating costs. Some research conducted with hydrous ethanol as well as practical experience in Brazil suggests that by not removing the last few percent of water from ethanol, the ethanol production costs would be lower and the water contained in ethanol might not cause driveability, not cause corrosion problems and not lower the fuel economy. A lot more research needs to be conducted before hydrous ethanol would be proven as a viable and safe motor vehicle fuel in existing U.S. vehicles.

### *Thermochemical Conversion of Cellulose to Ethanol*

Thermochemical conversion is another reaction pathway which exists for converting cellulose to ethanol. Thermochemical technology is based on the heat and pressure-based gasification or pyrolysis of nearly any biomass feedstock, including those we've highlighted as likely biochemical feedstocks. The syngas could then be converted into mixed alcohols, hydrocarbon fuels, chemicals, and power. To produce ethanol, the syngas is passed over a catalyst which converts the syngas to mixed alcohols – mainly methanol. The methanol can be reacted further to ethanol.

NREL has authored a thermochemical report which already provided a cost estimate.[1142] However, this report only hypothesized how a thermochemical ethanol plant could achieve production costs at a very low cost of $1 per gallon. However, to obtain a more detailed cost assessment that may be achievable within the timeframe of our program, EPA contracted NREL to assess the costs for a thermochemical technology which produces mixed alcohols for years 2010, 2015 and 2022.[1143] Table 4.1-26 summarizes the cost information provided by NREL.

**Table 4.1-26**
**Summary of Mixed Cellulosic Alcohol Production Costs by NREL**
**(2007 dollars, 10% after tax ROI)**

| | **2010** | | **2015** | | **2022** | |
|---|---|---|---|---|---|---|
| **Annual Ethanol Production** | 48.8 | | 56.7 | | 61.9 | |
| **Annual Total Alcohol Production** | 57.5 | | 66.6 | | 72.7 | |
| **Ethanol Yield** | 63.2 | | 73.4 | | 80.1 | |
| **Total Alcohol Yield** | 74.5 | | 86.2 | | 94.1 | |
| | | | | | | |
| **Capital Costs** | | | | | | |
| **Feed Handling and Drying** | 25.2 | | 25.2 | | 25.2 | |
| **Gasification** | 14.0 | | 14.0 | | 14.0 | |
| **Tar Reforming and Quench** | 53.4 | | 38.6 | | 41.6 | |
| **Acid Gas and Sulfur Removal** | 20.4 | | 14.6 | | 15.8 | |
| **Alcohol Synthesis Compression** | 35.4 | | 18.5 | | 17.3 | |
| **Other Synthesis Costs** | 6.1 | | 4.7 | | 5.1 | |
| **Alcohol Separation and Purification** | 6.8 | | 7.5 | | 7.8 | |
| **Steam System and Power Generation** | 19.2 | | 19.7 | | 18.2 | |
| **Cooling Water and other Utilities** | 4.2 | | 4.3 | | 3.9 | |
| **Total Installed Equipment Cost** | 184.7 | | 147.1 | | 148.9 | |
| **Added Cost Factors** | 72.1 | | 57.5 | | 58.1 | |
| **Total Project Investment** | 256.8 | | 204.6 | | 207.0 | |
| | | | | | | |
| **Operating and Amortized Capital Costs** | **$MM/yr** | **$/gal Ethanol** | **$MM/yr** | **$/gal Ethanol** | **$MM/yr** | **$/gal Ethanol** |
| **Feedstock** | 46.4 | 0.95 | 35.4 | 0.63 | 35.6 | 0.58 |
| **Catalysts** | 7.6 | 0.16 | 0.2 | 0.003 | 0.2 | 0.003 |
| **Olivine** | 0.5 | 0.01 | 0.5 | 0.01 | 0.5 | 0.01 |
| **Other Raw Materials** | 0.4 | 0.02 | 0.4 | 0.02 | 0.3 | 0.02 |
| **Waste Disposal** | 0.3 | 0.01 | 0.3 | 0.01 | 0.3 | 0.01 |
| **Electricity** | -1.8 | -0.04 | 0.0 | 0.00 | 0.0 | 0.00 |
| **Fixed Costs** | 14.8 | 0.30 | 12.7 | 0.23 | 12.8 | 0.21 |
| **Co-Product Credits** | -10.4 | -0.21 | -11.8 | -0.21 | -12.9 | -0.21 |
| **Capital Depreciation, Income Tax and Return on Investment** | 46.3 | 0.95 | 37.1 | 0.66 | 37.5 | 0.61 |
| **Total** | 104.1 | 2.15 | 74.8 | 1.33 | 74.3 | 1.21 |

In its mixed cellulosic alcohol report, NREL did not assess the technology's costs on the same basis that EPA is using. NREL used a feedstock cost of $46.1/dry ton which is lower than our estimate of $67.4/dry ton. Also, NREL amortized the capital costs based on a 10 percent after tax return on investment (ROI) compared to our 7% before tax ROI. Thus, we adjusted the NREL cellulosic mixed alcohol costs to reflect our feedstock costs and capital cost amortization assumptions. Table 4.1-27 contains a summary of the mixed cellulosic alcohol costs based on our feedstock and capital amortization cost assumptions.

**Table 4.1-27**
**Summary of Adjusted Mixed Cellulosic Alcohol Production Costs by NREL**
**(2007 dollars, 7% before tax ROI)**

| | 2010 | | 2015 | | 2022 | |
|---|---|---|---|---|---|---|
| **Operating and Amortized Capital Costs** | **$MM/yr** | **$/gal Ethanol** | **$MM/yr** | **$/gal Ethanol** | **$MM/yr** | **$/gal Ethanol** |
| **Feedstock** | 67.8 | 1.39 | 51.8 | 0.92 | 52.1 | 0.85 |
| **Catalysts** | 7.6 | 0.16 | 0.2 | 0.003 | 0.2 | 0.003 |
| **Olivine** | 0.5 | 0.01 | 0.5 | 0.01 | 0.5 | 0.01 |
| **Other Raw Materials** | 0.4 | 0.02 | 0.4 | 0.02 | 0.3 | 0.02 |
| **Waste Disposal** | 0.3 | 0.01 | 0.3 | 0.01 | 0.3 | 0.01 |
| **Electricity** | -1.8 | -0.04 | 0.0 | 0.00 | 0.0 | 0.00 |
| **Fixed Costs** | 14.8 | 0.30 | 12.7 | 0.23 | 12.8 | 0.21 |
| **Co-Product Credits** | -10.4 | -0.21 | -11.8 | -0.21 | -12.9 | -0.21 |
| **Capital Depreciation, Income Tax and Return on Investment** | 28.3 | 0.58 | 22.8 | 0.40 | 22.8 | 0.37 |
| **Total** | 107.5 | 2.22 | 76.8 | 1.38 | 76.0 | 1.26 |

### 4.1.1.3 Imported Sugarcane Ethanol Costs

Our analysis of imported ethanol costs began with a literature search of recent estimates for production costs for sugar cane ethanol in Brazil. Since the liberalization of ethanol prices in Brazil, few cost estimation studies have been made and most of the cost analyses refer to the same study.[1144] This study was carried out by the Brazilian Ministry of Science and Technology (MC&T), based on 1990 data, and referred to a production cost of $0.87/gallon. Table 4.1-28 gives a breakdown of costs based on this data.

**Table 4.1-28. Sugarcane Ethanol Production Costs in Brazil, circa 1990**

| | Average cost (US$ per gallon) |
|---|---|
| **Operating costs** | **$0.64** |
| Labor | $0.02 |
| Maintenance | $0.02 |
| Chemicals | $0.01 |
| Energy | $0.01 |
| Other | $0.02 |
| Interest payments on working capital | $0.08 |
| Feedstock (cane) | $0.48 |
| **Fixed costs** | **$0.23** |
| Capital at 12% depreciation rate | $0.19 |
| Other | $0.04 |
| **Total** | **$0.87** |

Since then, there have been significant variations in exchange rates, costs of sugarcane and oil products, etc. For example, earlier estimates may underestimate crude and natural gas costs which influence the cost of feedstock as well as energy costs at the plant. Another possible difference in production cost estimates is whether or not the estimates are referring to hydrous or anhydrous ethanol. Costs for anhydrous ethanol (for blending with gasoline) are typically several cents per gallon higher than hydrous ethanol (for use in dedicated ethanol vehicles in Brazil).[1145] It is not entirely clear from the majority of studies whether reported costs are for hydrous or anhydrous ethanol. Yet another difference could be the slate of products the plant is producing, for example, future plants may be dedicated ethanol facilities while others involve the production of both sugar and ethanol in the same facility. Due to economies of scale, production costs are also typically smaller per gallon for larger facilities. Table 4.1-29 summarizes the various estimates reported by others. Production costs range from as low as $0.57 per gallon of ethanol to as high as $1.48 per gallon of ethanol.

### Table 4.1-29. Other Sugarcane Ethanol Production Cost Estimates

| Reference | Cost (US$ per gallon) |
|---|---|
| AgraFNP. 2007. Sugar and Ethanol in Brazil: A Study of the Brazilian Sugar Cane, Sugar and Ethanol Industries. | $0.80-$1.07 per gallon (in 2006 $'s depending on region in Brazil), avg. is $0.78 per gallon for cane production cost and $0.13 per gallon for industrial costs |
| IEA. 2004. Biofuels for Transport: An International Perspective. | $0.87 per gallon (in 1990 $'s) references MC&T study; also reports recent production cost estimates for hydrous ethanol as low as $0.57 per gallon (at the prevailing exchange rate in Jan. 2004) |
| USDA. 2006. The Economic Feasibility of Ethanol Production from Sugar in the United States. | Avg. is $0.81 per gallon |
| Von Lampe, Martin. OECD. 2006. Working Party on Agricultural Policies and Markets: Agricultural Market Impacts of Future Growth in the Production of Biofuels. | $0.83 per gallon |
| Brazil Institute. April 2007. The Global Dynamics of Biofuels: Potential Supply and Demand for Ethanol. Issue No. 3. | $0.83 per gallon. |
| ESMAP. October 2005. Potential for Biofuels for Transport in Developing Countries. | $.87-$1.10 per gallon |
| OECD, March 2008. ITF Round Tables No. 138. Biofuels: Linking Support to Performance. | Avg. is $1.40 per gallon |
| Bain, R. December 2007. World Biofuels Assessment Worldwide Biomass Potential: Technology Characterizations. NREL/MP-510-42467. | $1.04-$1.48 per gallon depending on size of plant, i.e. 100 MGY-4.6 MGY; Sugarcane feedstock costs $0.68 per gallon, Variable operating costs $0.27 per gallon, Fixed costs $0.02-0.13 per gallon, and Capital costs $0.07-0.40 per gallon |
| Macedo, I.C. and L.A.H. Nogueira. 2005. "Biocombusíveis". Cadernos NAE, No. 2. Núcleo de Assuntos Estratégicos da Presidência da República, Brasilia; As sited in OECD, *op. sit.* | $0.79 per gallon in the Center-South Brazil |
| Kojima, M. and T. Johnson. 2006. "Potential for Biofuels for Transport in Developing Countries". ESMAP Knowledge Exchange Series, No. 4.; As sited in OECD, *op sit.* | $0.87-$1.09 per gallon |
| Smeets, E. 2008. The Sustainability of Brazilian Ethanol-An Assessment of the Possibilities of Certified Production. Biomass and Bioenergy | $1.18 assuming exchange rate of $1.20= 1 Euro |
| Van den Wall Bake, J.D., et. al. 2009. Explaining the experience curve: Cost reductions | $1.29 per gallon presently; Estimates for 2020 range from $0.76-$0.98 per gallon, Sugarcane costs |

| | |
|---|---|
| of Brazilian ethanol from sugarcane | $0.35-$0.46 per gallon, rest from industrial costs[GGGGGGGGGG] |

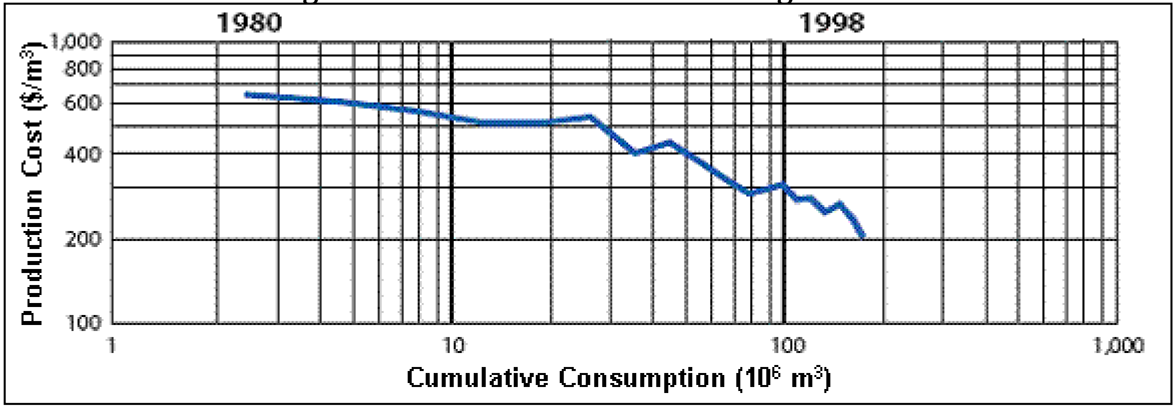
The study by OECD (2008) entitled "Biofuels: Linking Support to Performance", appears to provide the most recent and detailed set of assumptions and production costs. As such, our estimate of sugarcane production costs primarily relies on the assumptions made for the study, which are shown in Table 4.1-30. The estimate assumes an ethanol-dedicated mill and is based off an internal rate of return of 12%, a debt/equity ratio of 50% with an 8% interest rate and a selling of surplus power at $57 per MWh.

**Table 4.1-30. Cost of Production in a Standard Ethanol Project in Brazil**

| | |
|---|---|
| Sugarcane Productivity | 71.5 t/ha |
| Sugarcane Consumption | 2 million tons/year |
| Harvesting days | 167 |
| Ethanol productivity | 85 liters/ton (22.5 gal/ton) |
| Ethanol Production | 170 million liters/year (45 MGY) |
| Surplus power produced | 40 kWh/ton sugarcane |
| Investment cost in mill | USD 97 million |
| Investment cost for sugarcane production | USD 36 million |
| O & M (Operating & Maintenance) costs | $0.26/gal |
| Variable sugarcane production costs | $0.64/gal |
| Capital costs | $0.49/gal |
| Total production costs | **$1.40/gal** |

The estimate above is based on the costs of producing ethanol in Brazil on average, today. However, we are interested in how the costs of producing ethanol will change by the year 2022. Although various cost estimates exist, analysis of the cost trends over time shows that the cost of producing ethanol in Brazil has been steadily declining due to efficiency improvements in cane production and ethanol conversion processes. Between 1980 and 1998 (total span of 19 years) ethanol cost declined by approximately 30.8%.[1146] This change in the cost of production over time in Brazil is known as the ethanol cost "Learning Curve". See Figure 4.1-2.

**Figure 4.1-2. Ethanol Cost "Learning Curve"**



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[GGGGGGGGGG] Costs were given in $/TC and $/m$^3$, conversions were used to translate to per gallon numbers.

The change in ethanol costs will depend on the likely productivity gains and technological innovations that can be made in the future. As the majority of learning has already occurred, it is likely that the decline in ethanol costs will be less drastic in the future as the production process and cane practices have matured. Industrial efficiency gains are already at about 85% and are expected to increase to 90% in 2015.[1147] Most of the productivity growth is expected to come from sugarcane production, where yields are expected to grow from the current 70 tons/ha, to 96 tons/ha in 2025.[1148] Sugarcane quality is also expected to improve, with sucrose content growing from 14.5% to 17.3% in 2025. [1149] All productivity gains together could allow the increase in the production of ethanol from 6,000 liters/ha (at 85 liters/ton sugarcane) to 10,400 liters/ha (at 109 liters/ton sugarcane) in 2025. [1150]

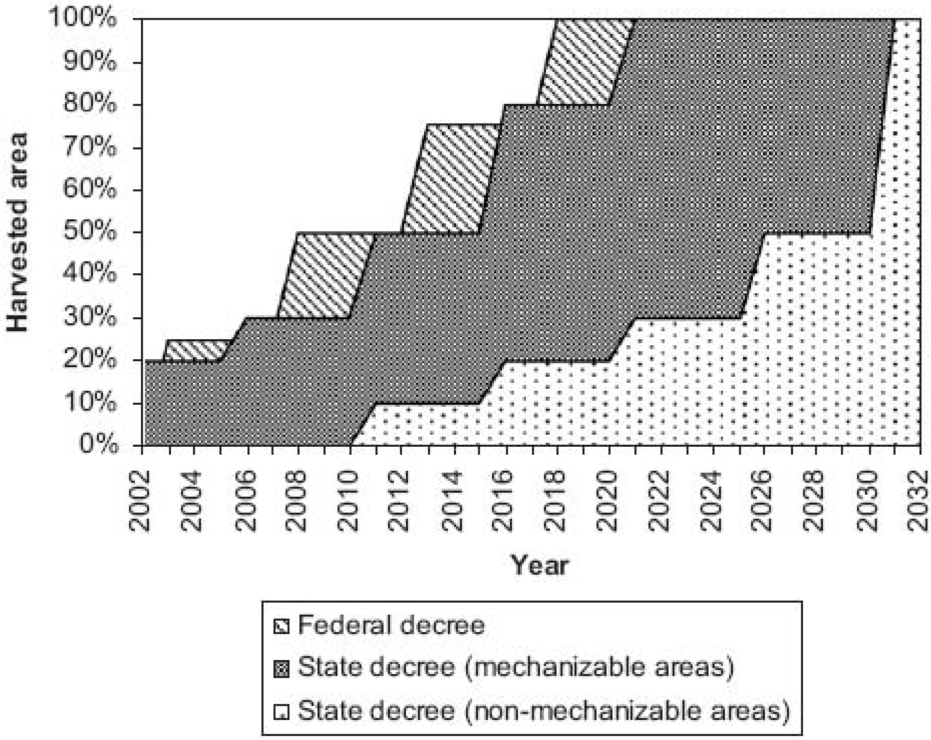
Assuming that ethanol productivity increases to 100 liters/ton by 2015 and 109 liters/ton by 2025, variable sugarcane ethanol production costs are be expected to decrease to approximately $0.51/gal from $0.64/gal since less feedstock is needed to produce the same volume of ethanol using the estimates from Table 4.1-30, above. Table 4.1-31 shows the calculated decrease for the years 2005-2025. We assumed a linear decrease between data points for 2005, 2015, and 2025. Adding operating ($0.26/gal) and capital costs ($0.49/gal) from Table 4.1-27, to a sugarcane cost of $0.51/gal, total production costs are $1.26/gal in 2022.

### Table 4.1-31.
### Estimated Decrease in Sugarcane Production Cost by 2022 Due to Increases in Ethanol Productivity

| | Sugarcane Production Cost $/gal | liters/ton | gal/ton |
|---|---|---|---|
| 2005 | 0.64 | 85 | 22.46 |
| 2006 | 0.63 | 86.5 | 22.85 |
| 2007 | 0.62 | 88 | 23.25 |
| 2008 | 0.61 | 89.5 | 23.65 |
| 2009 | 0.60 | 91 | 24.04 |
| 2010 | 0.59 | 92.5 | 24.44 |
| 2011 | 0.58 | 94 | 24.83 |
| 2012 | 0.57 | 95.5 | 25.23 |
| 2013 | 0.56 | 97 | 25.63 |
| 2014 | 0.55 | 98.5 | 26.02 |
| 2015 | 0.54 | 100 | 26.42 |
| 2016 | 0.54 | 100.9 | 26.66 |
| 2017 | 0.53 | 101.8 | 26.90 |
| 2018 | 0.53 | 102.7 | 27.13 |
| 2019 | 0.53 | 103.6 | 27.37 |
| 2020 | 0.52 | 104.5 | 27.61 |
| 2021 | 0.52 | 105.4 | 27.85 |
| **2022** | **0.51** | **106.3** | **28.08** |
| 2023 | 0.51 | 107.2 | 28.32 |
| 2024 | 0.50 | 108.1 | 28.56 |
| 2025 | 0.50 | 109 | 28.80 |

Brazil sugarcane producers are also expected to move from burned cane manual harvesting to mechanical harvesting. See Figure 4.1-3.[1151] As a result, large amounts of straw are expected to be available. Costs of mechanical harvesting are lower compared to manually harvesting, therefore, we would expect costs for sugarcane to decline as greater sugarcane producers move to mechanical harvesting. However, diesel use increases with mechanical harvesting and with diesel fuel prices expected to increase in the future, costs may be higher than expected. Therefore, we have not assumed any changes to harvesting costs due to the switchover from manual harvesting to mechanical harvesting.

**Figure 4.1-3. Phase-out Schedule for Trash Burning Practices**



As more straw is expected to be collected at future sugarcane ethanol facilities, there is greater potential for production of excess electricity. The production cost estimates in the OECD study assumes an excess of 40 kWh per ton sugarcane, however, future sugarcane plants are expected to produce 135 kWh per ton sugarcane assuming the use of higher efficiency condensing-extraction steam turbine (CEST) systems and use of 40% of available straw.[1152] Assuming excess electricity is sold for $57 per MWh, the production of an additional 95 kWh per ton would be equivalent to a credit of $0.22 per gallon ethanol produced. We have included this potential additional credit from greater use of bagasse and straw in our estimates at this time, calculated as a decrease in operating costs from $0.26 per gallon to $0.04 per gallon.

It is also important to note that ethanol production costs can increase if the costs of compliance with various sustainability criteria are taken into account. For instance, using organic or green cane production, adopting higher wages, etc. could increase production costs for sugarcane ethanol.[1153] Such sustainability criteria could also be applicable to other feedstocks, for example, those used in corn- or soy-based biofuel production. If these measures are adopted in the future, production costs will be higher than we have projected.

In addition to production costs, there are also logistical and port costs. We used the report from AgraFNP to estimate such costs since it was the only resource that included both logistical and port costs. The total average logistical and port cost for sugarcane ethanol is $0.20/gal and $0.09/gal, respectively, as shown in Table 4.1-32.

**Table 4.1-32.**

### Imported Ethanol Cost at Port in Brazil (2007 $'s)

| Region | Logistical Costs US ($/gal) | Port Cost US ($/gal) |
|---|---|---|
| NE Sao Paulo | 0.150 | 0.097 |
| W Sao Paulo | 0.210 | 0.097 |
| SE Sao Paulo | 0.103 | 0.097 |
| S Sao Paulo | 0.175 | 0.097 |
| N Parana | 0.238 | 0.097 |
| S Goias | 0.337 | 0.097 |
| E Mato Grosso do sul | 0.331 | 0.097 |
| Triangulo mineiro | 0.207 | 0.097 |
| NE Cost | 0.027 | 0.060 |
| Sao Francisco Valley | 0.193 | 0.060 |
| **Average** | 0.197 | 0.089 |

Total fuel costs must also include the cost to ship ethanol from Brazil to the U.S. The average cost from 2006-2008 was estimated to be approximately $0.17 per gallon of ethanol.[1154] Costs were estimated as the difference between the unit value cost of insurance and freight (CIF) and the unit value customs price. The average cost to ship ethanol from Caribbean countries (e.g. El Salvador, Jamaica, etc.) to the U.S. from 2006-2008 was approximately $0.13 per gallon of ethanol. Although this may seem to be an advantage for Caribbean countries, it should be noted that there would be some additional cost for shipping ethanol from Brazil to the Caribbean country. Therefore, we assume all costs for shipping ethanol to be $0.17 per gallon regardless of the country importing ethanol to the U.S.

The total imported ethanol fuel costs (at U.S. ports) over the time period of 2010 to 2022 are shown in Table 4.1-33. In 2022, the total sugarcane ethanol cost estimate prior to tariffs and taxes is $1.50/gallon. Direct Brazilian imports are also subject to an additional $0.54 per gallon tariff, whereas those imports arriving in the U.S. from Caribbean Basin Initiative (CBI) countries are exempt from the tariff. In addition, all imports are given an ad valorem tax of 2.5% for undenatured ethanol and a 1.9% tax for denatured ethanol. We assumed an ad valorem tax of 2.5% for all ethanol. Thus, including tariffs and ad valorem taxes, the average cost of imported ethanol is shown in Table 4.1-34 in the "Brazil Direct w/ Tax & Tariff" and "CBI w/ Tax" columns for the years 2010-2022.

### Table 4.1-33. Average Imported Ethanol Costs Prior to Tariff and Taxes

| | Sugarcane Production Cost ($/gal) | Operating Cost ($/gal) | Capital Cost ($/gal) | Logistical Cost ($/gal) | Port Cost ($/gal) | Transport Cost from Port to US ($/gal) | Total Cost ($/gal) |
|---|---|---|---|---|---|---|---|
| 2010 | 0.59 | 0.04 | 0.49 | 0.20 | 0.09 | 0.17 | 1.58 |
| 2011 | 0.58 | 0.04 | 0.49 | 0.20 | 0.09 | 0.17 | 1.57 |
| 2012 | 0.57 | 0.04 | 0.49 | 0.20 | 0.09 | 0.17 | 1.56 |
| 2013 | 0.56 | 0.04 | 0.49 | 0.20 | 0.09 | 0.17 | 1.55 |
| 2014 | 0.55 | 0.04 | 0.49 | 0.20 | 0.09 | 0.17 | 1.54 |
| 2015 | 0.54 | 0.04 | 0.49 | 0.20 | 0.09 | 0.17 | 1.53 |
| 2016 | 0.54 | 0.04 | 0.49 | 0.20 | 0.09 | 0.17 | 1.53 |
| 2017 | 0.53 | 0.04 | 0.49 | 0.20 | 0.09 | 0.17 | 1.52 |
| 2018 | 0.53 | 0.04 | 0.49 | 0.20 | 0.09 | 0.17 | 1.52 |
| 2019 | 0.53 | 0.04 | 0.49 | 0.20 | 0.09 | 0.17 | 1.52 |
| 2020 | 0.52 | 0.04 | 0.49 | 0.20 | 0.09 | 0.17 | 1.51 |
| 2021 | 0.52 | 0.04 | 0.49 | 0.20 | 0.09 | 0.17 | 1.51 |
| **2022** | **0.51** | **0.04** | **0.49** | **0.20** | **0.09** | **0.17** | **1.50** |

### Table 4.1-34. Average Imported Ethanol Costs

| | **Brazil Direct ($/gal)** | **Brazil Direct w/ Tax & Tariff ($/gal)** | **CBI ($/gal)** | **CBI w/ Tax ($/gal)** |
|---|---|---|---|---|
| 2010 | 1.58 | 2.16 | 1.58 | 1.62 |
| 2011 | 1.57 | 2.15 | 1.57 | 1.61 |
| 2012 | 1.56 | 2.14 | 1.56 | 1.60 |
| 2013 | 1.55 | 2.13 | 1.55 | 1.59 |
| 2014 | 1.54 | 2.12 | 1.54 | 1.58 |
| 2015 | 1.53 | 2.11 | 1.53 | 1.57 |
| 2016 | 1.53 | 2.11 | 1.53 | 1.57 |
| 2017 | 1.52 | 2.10 | 1.52 | 1.56 |
| 2018 | 1.52 | 2.10 | 1.52 | 1.56 |
| 2019 | 1.52 | 2.10 | 1.52 | 1.56 |
| 2020 | 1.51 | 2.09 | 1.51 | 1.55 |
| 2021 | 1.51 | 2.09 | 1.51 | 1.55 |
| **2022** | **1.50** | **2.08** | **1.50** | **1.54** |

### 4.1.2 Biodiesel Production Costs

*Virgin vegetable oils, fats, waste oils and greases costs*

The feedstocks that we project to make up the largest share of biodiesel are virgin vegetable oil (primarily soy oil) and non-food-grade corn oil generated as a co-product of dry mill ethanol production. These feedstock streams were included in the agricultural commodity modeling done for this rulemaking using the FASOM model. This work is described in detail in Section 2.5 of this RIA. Table 4.1-35 summarizes the volumes and costs of these feedstocks.

Rendered fats and other waste greases are expected to make up a smaller, but still important, source of biodiesel feedstock. These were not explicitly modeled by FASOM; [HHHHHHHHHH]therefore their value was estimated to be 70% that of soy oil, based on historical trends.

**Table 4.1-35. Summary of biodiesel feedstock use and cost for primary control case in 2022 (2007$).**

| **Fuel / Feedstock** | **Feedstock Price ($/lb)** | **Projected use in 2022 (MMgal)** |
|---|---|---|
| Soy oil | 0.33 [a] | 660 |
| Corn oil from dry mill ethanol production | 0.17 [a] | 680 |
| Yellow grease or other rendered fats | 0.23 [b] | 230 |
| Algae oil or other advanced feedstock | 0.58 [c] | 100 |

*Algae-derived oils costs*

Algae oil cost projections are based on Aspen modeling completed by NREL and are reported in 2007 dollars. Detailed cost information is provided in their report submitted to the docket.[1155] The results are summarized below in Figure 4.1-4. Two production pathways were assumed, open pond (OP) and photobioreactor (PBR) systems. For each production pathway a base case, aggressive case, and maximum development case were evaluated based on assumptions on key variables e.g., yield, lipid content on algae, etc. The oil production cost for the open pond case ranged from $11.25/gal in the base case to $3.99/gal for the max case. The oil production cost for the PBR case ranged from $19.49/gal in the base case to $6.62/gal in the max case.

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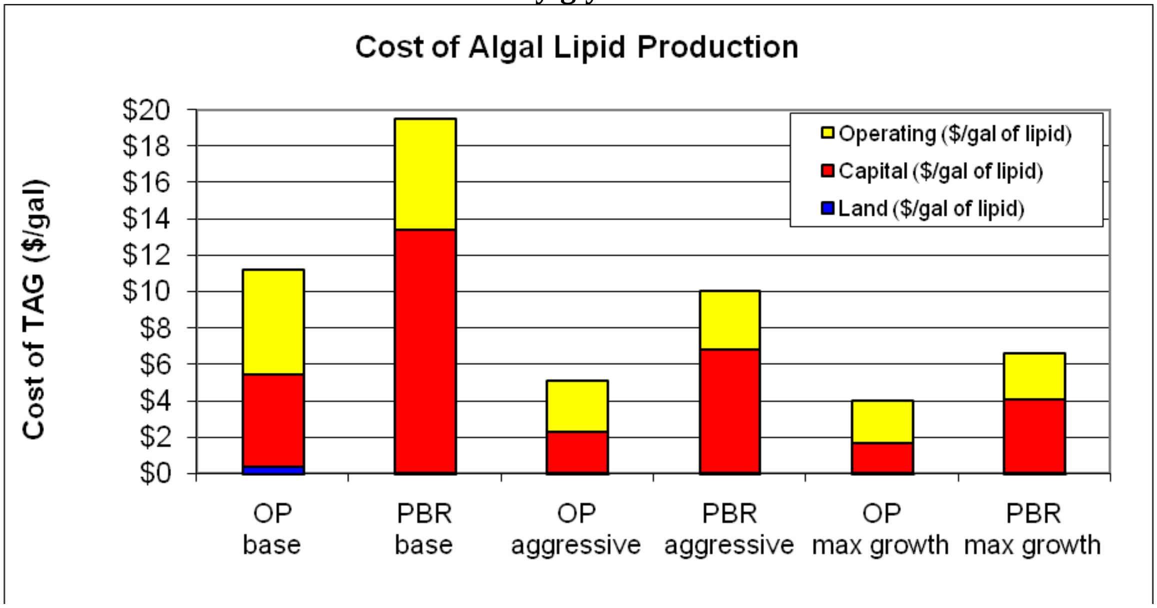
[HHHHHHHHHH] Data available from various sources suggests that tallow and yellow grease prices have been closer to half the value of crude soy oil, but we have chosen to assume 70% as this is what USDA/ARS had assumed during some initial cost modeling they had done for us. Also, given that rendered fat volumes will be more limited than vegetable feedstocks, we might expect their prices to rise against the alternative (and still more expensive) vegetable feedstocks in a climate of higher biofuel production.

**Figure 4.1-4.**
**Cost to Produce 10 MMgal/yr oil at growth rate scenarios developed by NREL for open pond (op) and photobioreactor (PBR) production. TAG = triacylglyceride**



Since algal biofuel technology is still in a relatively early stage of development, there is a higher degree of uncertainty associated with potential performance and cost relative to more established technologies. It is important to note that the "max" case merely means the maximum algae growth and oil content applied to the specific configuration and associated assumptions analyzed and does not imply that these are the absolute lowest costs that can ever be achieved as technology develops. For the algal technology systems analyzed, the report indicated that the areas with the highest economic impact include the optimum amount of nutrients required, the $CO_2$ delivery cost, the flocculant requirement for harvesting, and the material costs for the PBR production system. The economic modeling assumptions and results from NREL for microalgae-derived oil correspond well with other studies which report the cost of production for algae oil from $1 to >$40/gal.[1156]

NREL also investigated the uncertainty in key assumptions and the associated potential cost impact of such assumptions in a sensitivity analysis. Figure 4.1-5 shows that for open ponds, the amount of nutrients required has the highest impact on production cost of the variables evaluated. Figure 4.1-6 shows that the single largest cost item in the PBR system is the cost of the tubes themselves.

Figure 4.1-5. Open Pond Sensitivity Analysis

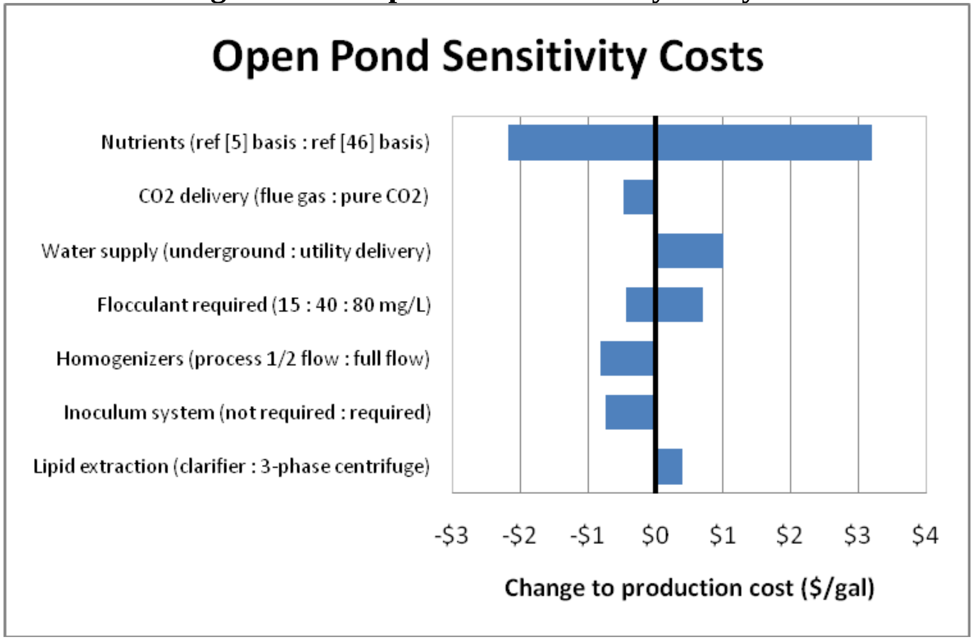
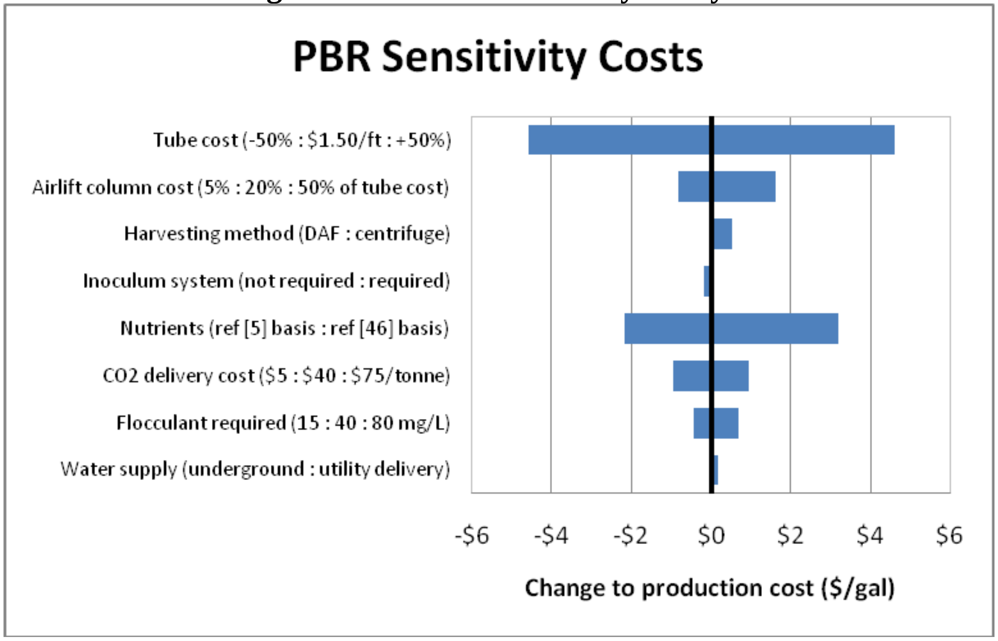


Figure 4.1-6: PBR Sensitivity Analysis



For this rulemaking, we made the simplifying assumption of using the production cost of the open pond aggressive case of $5.11/gal or $0.68/lb for this feedstock to estimate costs of algae-derived fuel. Given the uncertainties in estimating costs for algae as well as the need for a single-value estimate for algal oil for cost analyses purposes, we chose the open pond aggressive case which appears to represent a somewhat middle value as well as a more reasonably competitive feedstock with alternatives, such as soy oil.

### *Biodiesel production costs*

Biodiesel production costs for this rule were estimated using two variations of a model generated by USDA for a 10 million gallon-per-year transesterification biodiesel plant. One version uses degummed soy oil as feedstock, and a second version includes acid pre-treatment steps required to utilize feedstocks such as rendered fat and yellow grease, which have higher free fatty acid content. USDA used the SuperPro Designer chemical process simulation software to build up a process model with estimates of heat and material flowrates and equipment sizing. Outputs from this model were then combined in a spreadsheet with capital, energy, labor, and feedstock costs to generate a final estimate of production cost. Additional details on the model are given in a 2006 technical publication in the peer-reviewed scientific journal Bioresource Technology.[1157] At 10 million gallons per year, the modeled plant size is between the mean and median plant sizes (16 million and 6 million gal/yr, respectively) as given in our industry characterization. Therefore, the model cost estimate is believed to be sufficiently accurate for our analyses and no further work was done to determine the effect of scale on production cost.

This model is periodically updated by USDA to reflect technology upgrades, changes to cost of capital, etc. Such an update was made to the model just before its outputs were used in the analyses presented here. We also made modifications to the capital cost to be consistent with typical cost amortization schemes used for regulatory programs. The capital charge estimate was derived as shown in Table 4.1-36. Installed capital cost was $11.9 million; adding 3% annual maintenance charge, we arrive at a final capital charge of 14% annually. Energy prices were taken from AEO 2009: natural gas at $7.75/MMBtu and electricity at $0.066/kWh for 2022 in 2007 dollars.

**Table 4.1-36. Economic Factors Used in Deriving the Capital Cost Amortization Factor**

| Amortization Scheme | Depreciation Life | Economic and Project Life | Federal and State Tax Rate | Return on Investment (ROI) | Annual Maintenance Charge | Resulting Capital Amortization Factor |
|---|---|---|---|---|---|---|
| Societal Cost | 10 Years | 15 Years | 0% | 7% | 3% | 0.14 |

The value of the glycerin co-product has been depressed and volatile in recent years due to a large increase in production in biodiesel facilities. This has been balanced at times by new uses coming online as feedstocks for traditionally petrochemical-based products as well as increased demand in personal care and other consumer products as the standard of living increases in many parts of the world. Some facilities are even experimenting with using it as a supplemental fuel along with biomass or other materials. We can expect that new uses for glycerin will continue to be found as long as it is plentiful and cheap. For a simple and conservative projection of its value in the future, we have assumed an energy-equivalent value based on residual heating oil. Using a heating value of 7,979 Btu/lb and a heating oil value of $18.90/MMBtu in 2022, we arrive at $0.15/lb as a co-product value. Table 4.1-37 shows the overall process material balance output by the model.

**Table 4.1-37. Material Balance and Values for Biodiesel Production Model in 2022**

| Stream | By weight | Estimated value (2007$) |
|---|---|---|
| Soy oil input | 100 | $0.33/lb |
| Methanol input | 11 | $0.16/lb |
| Biodiesel output (main product) | 100 | - |
| Glycerin output (co-product) | 12 | $0.15/lb |

Table 4.1-38 shows the production cost allocation for the soy oil-to-biodiesel facility as modeled in the 2022 primary control case. Production cost for biodiesel is primarily a function of feedstock price, with other process inputs, facility, labor, and energy comprising much smaller fractions.

**Table 4.1-38. Production cost allocation for soy biodiesel derived from this analysis for the primary control case in 2022**

| Cost Category | Share of Per-Gallon Cost |
|---|---|
| Soy Oil | 85% |
| Other Materials [a] | 6% |
| Capital & Facility | 6% |
| Labor | 2% |
| Utilities | 2% |

[a] Includes acids, bases, methanol, catalyst

### 4.1.3 Renewable Diesel Production Costs

The renewable diesel process converts rendered fats (or plant oils) into diesel fuel using thermal depolymerization, which is similar to refinery hydrotreating used to remove sulfur. The process uses hydrogen and catalyst to remove oxygen from the triglyceride molecules in the feedstocks oils via a decarboxylation and hydro-oxygenation reaction, yielding some light petroleum products and water as byproducts. The reactions also saturate the olefin bonds in the feedstock oils, converting them to paraffins, and may also isomerize some paraffins. Depending on process operating conditions, the yield to diesel-range material is typically between 90-99% volume, with the rest being naphtha and light fuel gases (primarily propane).

As described in the industry characterization discussion (see RIA Section 1.5.4), we have chosen to focus on stand-alone renewable diesel production, as we believe this will be the primary pathway given tax incentives and the definition of the biomass-based diesel fuel category. We assume a total project cost of $150MM for a standalone facility based on materials made publically available by Syntroleum Corp. related to their Geismar, LA, project.[1158]

Our operating cost and yield estimates were derived from material presented by UOP and Eni at a 2007 industry conference, which describes producing renewable diesel in a grass roots standalone production process inside a refinery.[1159] In addition to feedstock and facility costs, another significant cost input is hydrogen. For hydrogen operating costs, we used the UOP analysis and guidance from Conoco Philips to derive our estimate to make renewable diesel. [1160] The UOP paper presents a range of 1000 to 2000 standard cubic feed (scf) per barrel for converting the various feedstock to renewable diesel. Based on characteristics of rendered fats, we estimated a hydrogen demand of 1,590 SCF/bbl of feedstock processed.

Accounting for this quantity of hydrogen, along with a value taken from our refinery modeling work, we derived a figure of 6.9 cents/gallon of diesel product to cover utilities, labor, and other costs. Finally, total cost per gallon was estimated at $2.42 for the 2022 primary control case (2007 dollars). Table 4.1-39 gives more details for the process assumed in this analysis. Co-product values were also taken from refinery modeling work done for this rulemaking. Table 4.1-40 shows the cost allocation we arrived at for renewable diesel production.

**Table 4.1-39.**
**Parameters used in renewable diesel production cost estimates.**

| Stream | By volume | Estimated value (2007$) |
|---|---|---|
| Fat input | 100 gal | $0.23/lb |
| Hydrogen input | 505 scf | $0.0044/scf |
| Renewable diesel output (main product) | 93.5 gal | - |
| Naphtha output (co-product) | 5 gal | $0.55/lb |
| Light fuel gas output (co-product) | 9 gal | $0.13/lb |

**Table 4.1-40.**
**Production Cost Allocation for Renewable Diesel for Primary Control Case in 2022**

| Cost Category | Contribution to Cost |
|---|---|
| Feedstock | 78% |
| Capital & Facility | 11% |
| Hydrogen | 7% |
| Other variable costs | 3% |

## 4.1.4. Biodiesel and Renewable Diesel Cost Summary

Table 4.1-41 summarizes the feedstock prices and fuel production cost for biodiesel. Table 4.1-42 gives the same information for renewable diesel. Combined with information from Table 4.1-35, a weighted average production cost could be estimated (our overall economic impacts take into account this information).

**Table 4.1-41**
**Summary of Costs for Biodiesel for the Primary Control Case in 2022**

| Fuel / Feedstock | Feedstock Price ($/lb) | Fuel Production Cost ($/gal) |
|---|---|---|
| Biodiesel / soy oil | 0.33 [a] | 2.73 |
| Biodiesel / corn oil extraction at ethanol plants | 0.17 [a] | 1.90 |
| Biodiesel / yellow grease or other rendered fats | 0.23 [b] | 2.43 |
| Biodiesel / algae or other advanced virgin oil feedstock | 0.58 [c] | 4.52 [d] |

[a] Taken from outputs of FASOM model.
[b] Derived from outputs of FASOM model, assuming 70% value of soy oil.
[c] Derived from figures in a Technical Memo by Ryan Davis of NREL entitled “Techno-economic analysis of microalgae-derived biofuel production” (available in docket).
[d] This production cost assumes this advanced feedstock has very low free fatty acid content.

**Table 4.1-42**
**Summary of Cost for Renewable Diesel for the Primary Control Case in 2022**

| Fuel / Feedstock | Feedstock Price ($/lb) | Fuel Production Cost ($/gal) |
|---|---|---|
| Renewable diesel / yellow grease or other rendered fats | 0.23 [a] | 2.42 |

[a] Derived from outputs of FASOM model, assuming 70% value of soy oil.

### 4.1.5 BTL Diesel Production Costs

Biofuels-to-Liquids (BTL) processes, which are also thermochemical processes, convert biomass to liquid fuels via a syngas route. If cellulose is converted to syngas, rather than converting the syngas to mixed alcohols, a Fischer Tropsch reactor can be added to convert the syngas to diesel fuel and naphtha. The primary product produced by this process is diesel fuel. This technology is commonly termed biomass-to-liquids (BTL) because of its similarity to gas-to-liquids and coal-to-liquids technology. Diesel fuel's higher energy density per gallon than ethanol and even biodiesel provides it an inherent advantage over these other fuels. In addition, BTL diesel fuel can be more easily distributed from production to retail outlets and used by motor vehicles. The diesel fuel produced by the Fischer Tropsch process tends to be comprised of paraffins which provide a much higher cetane number than petroleum diesel fuel, with a downside of poorer cloud point which reduces its widespread use in cold temperatures.

There are many steps involved in a BTL process which makes this a capital-intensive process. The first step, like all the cellulosic processes, requires that the feedstocks be processed to be dried and ground to a fine size. The second step is the syngas step, which thermochemically reacts the biomass to carbon monoxide and hydrogen. Since carbon monoxide production exceeds the stoichiometric ideal fraction of the mixture, a water shift reaction must be carried out to increase the relative balance of hydrogen. The syngas products must then be cleaned to facilitate the following Fischer-Tropsch (FT) reaction. The Fischer-Tropsch reaction reacts the syngas to a range of hydrocarbon compounds – a type of synthetic crude oil. This hydrocarbon mixture is then hydrocracked to maximize the production of high cetane diesel fuel, although some low octane naphtha and small amounts of wax are also produced. The many steps of the BTL process contribute to its high capital cost.

Although there were several studies available which provided costs estimates for BTL diesel fuel, they did not provide sufficient detail to understand all the cost elements of BTL diesel fuel and naphtha. EPA therefore contracted with NREL to estimate the production costs for BTL diesel fuel and naphtha. Like the other technologies, we asked for cost estimates for the same years assessed above for cellulosic ethanol which was for 2010, 2015 and 2022, however, NREL did not believe that the costs would change that much over this time span. So NREL only provided the costs for 2022, advising us that the costs would only be slightly less for earlier years, and most of that difference would because of the poorer economies of scale if the initial plants are sized smaller. Table 4.1-43 summarizes the cost information provide by NREL to EPA for a year 2022 cellulosic BTL plant.

### Table 4.1-43
### Year 2022 Production Costs for Thermochemcal (BTL) Cellulosic Fischer Tropsch Diesel Fuel Provided by NREL (2007 dollars and 10% after tax rate of return)

| Plant Size MMgal/yr | 33.2 Diesel Fuel<br>49.4 All Liquid |
|---|---|
| Capital Cost $MM | 346 |
| Capital Cost 10% ROI after taxes ($MM/yr) | 61.7 |
| Fixed Costs ($MM/yr) | 18.3 |
| Feedstock Cost ($MM/yr) | 39.1 |
| Coproduct Credit ($MM/yr)[a] | -53.5 |
| Other raw material Costs ($MM/yr) | 0.9 |
| Waste Disposal and Catalyst Costs ($MM/yr) | 1.1 |
| Total Costs ($MM/yr) | 79 |
| Total Costs (cents/gallon of diesel fuel) | 206 |

a Based on a naphtha coproduct value of 327 cents per gallon.

NREL estimated that diesel fuel made by a 33 million gallon per year FT plant in 2022 could be produced at $2.06 per gallon estimated (in year 2007 dollars).[1161] Three adjustments however are needed to make the NREL production cost compatible with the rest of our analysis: 1) increase the feedstock costs, 2) reduce the capital charge costs and 3) adjust the co-product prices for naphtha and wax.

For capital charges, the NREL costs were based on amortizing capital assuming a 10 percent rate of return after taxes, using an annual capital charge factor of 0.178. The report's estimate for capital costs was $346 million for the plant, resulting in annual capital cost of $61.6 million or $1.85 per gallon of diesel fuel produced. We adjusted the capital cost by amortizing the capital cost assuming a 7 percent rate of return before taxes, using an annual capital charge factor of 0.11 which resulted in yearly cost of $38 million or $1.14 per gallon of diesel fuel produced.

In the NREL study, the total operating cost due to feedstock is $1.17 per gallon, using wood at $50.7 per dry ton. We adjusted the feedstock cost to $67.4 per dry ton, see subsection 4.1.1.2.1**,** which increased the feedstock costs to $1.56 per gallon of diesel fuel.

In the NREL analysis, the co-products produced have a credit value of $1.60 per gallon of diesel fuel, assuming a price for naphtha of $3.27 per gallon and wax at $0.49 per pound. The price of naphtha was set by NREL at 40 cents per gallon below the price of gasoline to account for its low octane value. The naphtha produced by the BTL process is also largely comprised of paraffins, however, as a gasoline blendstock it is poor because its octane could potentially be as low as 50. This material could be processed by refinery isomerization units raising its octane to perhaps 70 octane, but it cannot be processed by refinery reformers since it does not contain the napthenic compounds that are necessary for octane improvement by those units. Because of the large amount of octane rich ethanol which is expected to be made available from both corn and cellulose, it could be that BTL naphtha could be blended along with the ethanol into the gasoline pool. Rather than prejudge how this naphtha may be utilized in the future, for our cost analysis we simply assigned it a coproduct credit. So we set the BTL naphtha cost to be 83% as much of the cost of BTL diesel fuel based on its relative energy density. This results in a naphtha price of $1.98 per gallon. We adjusted the price of wax, by ratio-ing the NREL price by the change in price for naphtha. The price adjustment for naphtha and wax, results in a co-product value of $0.97 per gallon of FT diesel produced. The result is a diesel fuel production cost of $2.37 per gallon from the FT process.

Table 4.1-44 summarizes NREL's estimated and projected production costs for a thermochemical Fischer Tropsch biochemical cellulosic ethanol plant technology for their projected year 2022 technology in 2007 dollars reflecting a 7 percent before tax rate of return on investment. The costs are based on a cellulosic feedstock cost of $67.4 per dry ton.

Table 4.1-44
**Year 2022 Production Costs for Thermochemcal (BTL) Cellulosic Fischer Tropsch Diesel Fuel Provided by NREL (2007 dollars and 7% before tax rate of return)**

| Plant Size MMgal/yr | 33.2 Diesel Fuel<br>49.4 All Liquid |
|---|---|
| Capital Cost $MM | 346 |
| Capital Cost 7% ROI before taxes ($MM/yr) | 38 |
| Fixed Costs ($MM/yr) | 18 |
| Feedstock Cost ($MM/yr) | 52 |
| Coproduct Credit ($MM/yr)[a] | -32 |
| Other raw matl. Costs ($MM/yr) | 1.5 |
| Waste Disposal and Catalyst Costs ($MM/yr) | 1.5 |
| Total Costs ($MM/yr) | 79 |
| Total Costs (cents/gallon of diesel fuel) | 237 |

a Based on a naphtha coproduct value of 198 cents per gallon.

Initially, the estimated cost of $2.37 per gallon seems high relative to the projected cost for a year 2022 biochemical cellulosic ethanol plant, which is 126 cents per gallon of ethanol (see subsection 4.1.1.2.4)**.** However, ethanol provides about half the energy content on a per gallon basis as Fischer Tropsch diesel fuel. So, if we double the biochemical cellulosic ethanol costs to $2.52 to be consistent with the energy per diesel fuel-equivalent gallon, the estimated costs are very consistent between the two. The cellulosic biofuel tax subsidy currently favors the biochemical ethanol plant, though, because it is a per-gallon subsidy regardless of the energy content, and it therefore offsets twice as much cost as the BTL plant producing diesel fuel. However, the cellulosic diesel fuel may still be more valuable in the marketplace than cellulosic ethanol. In 2008 and for much of 2009 diesel fuel was priced higher than gasoline, and if this trend continues in the future, it may provide a better market for selling the BTL diesel fuel than for selling biochemical ethanol into the E85 market.

It was necessary to estimate cellulosic diesel fuel costs for previous years for the year-by-year cost analysis (see Section 4.4). However, NREL did not provide costs for previous years, although NREL did say that the primary difference in costs for the previous years would be economies of scale impacts for the capital costs due to smaller sized plants. Thus, to derive a cost for 2010, we estimated that the cellulosic diesel fuel plants that would be installed in 2010 would be half the size of the plant estimated for 2022. While the total capital costs decrease, the capital costs increase relative to the volume of cellulosic diesel fuel produced. We increased the naphtha credit from 198 cents per gallon to 216 cents per gallon to maintain an 83% cost percentage relative to the cellulosic diesel fuel. For this smaller plant size, we estimate the cost for cellulosic diesel fuel to be 258 cents per gallon.

*Other Cellulosic Diesel Fuel Costs*

For our volumes analysis, we assumed early on for our final rule analysis that there would likely be one or more other cellulosic diesel fuel technologies, other than BTL, producing cellulosic diesel fuel. However, we were either not able to obtain cost information from them, or we were uncertain enough about their future that we felt that we should not base the cost of the program on them. For example, Cello Energy has already built a cellulosic diesel fuel facility in Alabama here in the US with projected costs of about one dollar per gallon of diesel fuel. However, the facility has had difficulty operating as designed. As a result, perhaps very conservatively, we assumed that the other cellulosic diesel fuel costs would be the same as the BTL diesel fuel costs, and used the 237 cents per gallon cost for BTL diesel fuel for the entire cost for cellulosic diesel fuel.

## 4.2 Renewable Fuel Distribution Costs

Our analysis of the costs associated with distributing the volumes of biofuels that we project will be used under RFS2 focuses on: 1) the capital cost of making the necessary upgrades to the fuel distribution infrastructure system directly related to handling these fuels, and 2) the ongoing additional freight costs associated with shipping renewable fuels to the point where they are blended with petroleum-based fuels. Our analysis considers distribution costs within the U.S. only. The costs associated with bringing ethanol imports to the U.S. are considered in the context of the cost of the imports themselves. We chose to evaluate the distribution costs for cellulosic distillate and renewable diesel together because the same considerations apply to their handling in the fuel distribution system and because the projected volume of renewable diesel fuel is relatively small. The following sections outline our estimates of the distribution costs for the additional volumes of ethanol, cellulosic distillate fuel/renewable diesel fuel, and biodiesel that we project will be used to meet the RFS2 standards. There will be ancillary costs associated with upgrading the basic rail, marine, and road transportation nets to handle the increase in freight volume due to the RFS2. We have not sought to quantify these ancillary costs because 1) the growth in freight traffic that is attributable to RFS2 represents a minimal fraction of the total anticipated increase in freight tonnage (approximately 0.4% by 2022, see Section 1.6.3 of this RIA), and 2) we do not believe there is an adequate way to estimate such non-direct costs.

The biofuels used in response to the RFS2 standards will displace petroleum-based fuels that would otherwise be used. Thus, it would be appropriate to subtract the distribution costs for the displaced petroleum-based fuels from the distribution costs attributed to the biofuels that replace these petroleum-based fuels. However, we chose not to do so as it is difficult to project exactly what changes would result in cost savings. As a result, our analysis should provide a conservatively high estimate of biofuel distribution costs given the uncertainties in our analysis.

A discussion of the changes that will be needed in the biofuels distribution system to accommodate the increased volumes of biofuels that we project will be used to meet the RFS2 standards is contained in Section 1.6 of this RIA. In this Section, we further detail the nature of these projected changes and estimate the associated costs. Distribution capital costs associated with the additional volume of ethanol, cellulosic distillate fuel/renewable diesel, and biodiesel that we project will be used by 2022 to meet the RFS2 standards under the primary mid-ethanol scenario relative to the AEO 2007 reference case totals $8.4 billion, of which 68% is attributed to ethanol, 17% to cellulosic distillate/renewable diesel fuel, and 14% to biodiesel.

### 4.2.1 Ethanol Distribution Costs

As discussed in the following sections, we estimate that the total capital costs in the U.S to support distribution of the additional volume of ethanol that will be used to meet the RFS2 standards under the primary mid-ethanol scenario will be $5.5 billion by 2022 relative to the AEO 2007 reference case. When amortized, this translates to 7 cents per gallon of additional ethanol used to meet the RFS2 standards. Amortization of capital costs was done over 15 years at a 7% annual cost of capital except in the case of the cost of tank trucks where a 10 year amortization schedule was used. These costs were calculated relative to the AEO 2007 baseline which projects that 13.2 BGY of ethanol would be used in 2022 absent the RFS2 standards. Under the mid-ethanol primary scenario, we project that 22.2 BGY of ethanol will be used by 2022. Ethanol freight costs are estimated to be 13 cents per gallon on a national average basis. Thus, we estimate that total ethanol distribution costs will be 20 cents per gallon of ethanol that we project will be used to meet the RFS2 standards.[IIIIIIIII]

The ethanol distribution capital and freight costs for all the control scenarios relative to the 2 reference cases that we evaluated in this FRM is summarized in Table 4.2-1. The itemized ethanol capital costs are presented in Table 4.2-2 relative to the AEO 2007 reference case, and in Table 4.2-3 relative to the RFS1 reference case. These costs do not include the potential costs to supply butane to terminals for E85 blending, which are presented in Table 4.2-4. The way in which we estimated these costs is detailed in the following sections.

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[IIIIIIIII] As noted previously, we chose not to subtract the distribution costs for the petroleum-based fuels that would be displaced by the use of biofuels from our estimated biofuel distribution costs. We believe that the freight costs to ship petroleum-based fuels to the terminal are approximately 4 cents per gallon. If we were to subtract these costs from the estimated ethanol distribution costs under the mid-ethanol scenario relative to the AEO 2007 reference case, the result would be 16 cents per gallon.

### Table 4.2-1.
### Summary of Estimated Ethanol Distribution Capital and Freight Costs for the RFS2 Control Scenarios Relative to the Reference Cases

| | Low-Ethanol Scenario | | Mid-Ethanol Scenario | | High-Ethanol Scenario | |
|---|---|---|---|---|---|---|
| | RFS1 Reference | AEO Reference | RFS1 Reference | AEO Reference | RFS1 Reference | AEO Reference |
| Billion $ Capital | 5.5 | 3.0 | 7.9 | 5.5 | 11.9 | 9.9 |
| Capital Costs (cpg) | 6 | 8 | 6 | 7 | 5 | 6 |
| Freight Costs (cpg) | 13 | 13 | 13 | 13 | 12 | 12 |
| Total Distribution Costs (cpg) | 19 | 21 | 19 | 20 | 17 | 18 |

### Table 4.2-2.
### Summary of Estimated Ethanol Distribution Capital Costs for the RFS2 Control Scenarios Relative to the AEO 2007 Reference Case

| | Capital Cost (Million $) | | |
|---|---|---|---|
| | Low-Ethanol Scenario | Mid-Ethanol Scenario | High-Ethanol Scenario |
| Rail Cars | 365 | 760 | 1,699 |
| Barges | 22 | 45 | 102 |
| Tank Trucks | 42 | 87 | 194 |
| Storage Tanks at Petroleum Terminals | 355 | 739 | 1,568 |
| Blending and other Miscellaneous Equipment at Petroleum Terminals | 345 | 411 | 503 |
| Unit Train Receipt Facilities | 238 | 434 | 748 |
| Manifest Rail Receipt Facilities | 7 | 12 | 21 |
| Marine Receipt Facilities for Inta-U.S. Transport | 76 | 100 | 144 |
| Import Receipt Facilities | 49 | 53 | 63 |
| E85 Retail Facilities | 1,526 | 2,863 | 4,893 |
| Total (Million $) | 3,025 | 5,505 | 9,935 |
| Total (cpg) | 8 | 7 | 6 |

### Table 4.2-3.
### Summary of Estimated Ethanol Distribution Capital Costs for the RFS2 Control Scenarios Relative to the RFS1 Reference Case

| | Capital Cost (Million $) | | |
|---|---|---|---|
| | Low-Ethanol Scenario | Mid-Ethanol Scenario | High-Ethanol Scenario |
| Rail Cars | 884 | 1,279 | 2,218 |
| Barges | 53 | 77 | 133 |
| Tank Trucks | 107 | 154 | 268 |
| Storage Tanks at Petroleum Terminals | 859 | 1,243 | 2,073 |
| Blending and other Miscellaneous Equipment at Petroleum Terminals | 1,006 | 1,064 | 1,144 |
| Unit Train Receipt Facilities | 444 | 586 | 838 |
| Manifest Rail Receipt Facilities | 15 | 20 | 28 |
| Marine Receipt Facilities for Inta-U.S. Transport | 98 | 130 | 186 |
| Import Receipt Facilities | 49 | 53 | 63 |
| E85 Retail Facilities | 1,957 | 3,293 | 4,973 |
| Total (Million $) | 5,471 | 7,898 | 11,922 |
| Total (cpg) | 6 | 6 | 5 |

### Table 4.2-4.
### Potential Costs to Provide Butane to Terminals for E85 Blending for the RFS2 Control Scenarios

| | Capital Cost (Million $) | | |
|---|---|---|---|
| | Low-Ethanol Scenario | Mid-Ethanol Scenario | High-Ethanol Scenario |
| Butane Blending, Storage, Receipt and Other Miscellaneous Terminal Costs | 235 | 536 | 1,249 |
| Tank Trucks | 325 | 830 | 837 |
| Rail Cars | 32 | 81 | 89 |
| Total Capital Costs | 592 | 942 | 2,175 |
| Freight Cost (Annual cost in 2022) | 16 | 24 | 40 |
| Total Butane Distribution Costs Relative to the RFS1 Reference Case (cpg ethanol) | 1 | 1 | 1 |
| Total Butane Distribution Costs Relative to the AEO Reference Case (cpg ethanol) | 2 | 2 | 2 |

### 4.2.1.1 Capital Costs to Upgrade the Ethanol Distribution System

4.2.1.1.1 Petroleum Terminal Ethanol Distribution Capital Costs

The terminal facility modifications needed to support the use of the volume of ethanol that we project will be used to meet the RFS2 standards are discussed in Section 1.6.7. A summary of the costs associated with these modifications is detailed in Tables 4.2-5 and 4.2-6.

**Table 4.2-5.**
**Ethanol Associated Petroleum Terminal Costs**
**for the RFS2 Control Scenarios Relative to the AEO Reference Case**

| | Capital Cost (Million $) | | |
|---|---|---|---|
| | Low-Ethanol Scenario | Mid-Ethanol Scenario | High-Ethanol Scenario |
| Total Costs | 858 | 1,150 | 1,913 |
| Total Storage Tank Costs | 355 | 739 | 1,568 |
| New Storage Tank Construction Costs | 291 | 606 | 1,287 |
| Cost to Retrofit Existing Storage Tanks | 64 | 133 | 282 |
| Costs to Prepare Terminals to Handle Ethanol for the First Time | 167 | 167 | 167 |
| Tank Truck Unloading Facilities | 277 | 186 | 123 |
| Ethanol Blending and Miscellaneous Ethanol Handling Costs | 59 | 57 | 55 |

**Table 4.2-6.**
**Ethanol Associated Petroleum Terminal Costs**
**for the RFS2 Control Scenarios Relative to the RFS1 Reference Case**

| | Capital Cost (Million $) | | |
|---|---|---|---|
| | Low-Ethanol Scenario | Mid-Ethanol Scenario | High-Ethanol Scenario |
| Total Costs | 2,003 | 2,307 | 3,078 |
| Total Storage Tank Costs | 859 | 1,243 | 2,073 |
| New Storage Tank Construction Costs | 705 | 1,020 | 1,701 |
| Cost to Retrofit Existing Storage Tanks | 154 | 223 | 372 |
| Costs to Prepare Terminals to Handle Ethanol for the First Time | 594 | 594 | 594 |
| Tank Truck Unloading Facilities | 366 | 286 | 231 |
| Ethanol Blending and Ancillary Ethanol Handling Costs | 184 | 183 | 180 |

The above cost estimates are bases on the following. Input from terminal operators indicates that the primary modifications needed to prepare a terminal to handle ethanol for the first time are associated with the modification of vapor recovery equipment to handle ethanol-containing gasoline at a cost of $1,000,000 per terminal. We added another $20,000 to account for related ancillary costs. Input from terminal operators indicates that the cost of ethanol blending equipment is $300 thousand for E10-capable equipment, $310 thousand for E85-capable equipment, and $10,000 to upgrade E10-capable equipment to handle E85. Input from companies that are familiar with the installation of ethanol truck unloading equipment at terminals indicates that the cost averages $500 thousand per facility. Input from terminal operators indicates that the cost of new ethanol storage tank construction is $40 per barrel of capacity, and that the cost of retrofitting existing gasoline storage tanks for ethanol service is $5 per barrel of capacity for the size of tanks that are likely to be used.

#### 4.2.1.1.2 Capital Cost of Unit Train Receipt Facilities for Ethanol

Our estimation of the number of unit train receipt facilities that will be need to support the transport of the volumes of ethanol and cellulosic distillate fuel that we project will be used to meet the RFS2 standards is discussed in Section 1.6.4 of this RIA. Input from industry indicates that the cost of unit train receipt facility capable of handling 229 million gallons of biofuels per year is $10 million and the cost of a facility capable of handling 613 million gallons is $25 million. We interpolated between these two estimates to derive a cost estimate for each unit train receipt facility that we projected will be constructed based on its anticipated annual throughput volume. The total cost of unit train receipt facilities was divided between ethanol and cellulosic distillate fuel/renewable diesel fuel in proportion to the fraction of the total ethanol + cellulosic distillate fuel/renewable diesel fuel volume under the respective control scenario.

Our projections of the total cost of unit train receipt facilities and the portion that we attributed to the volume of ethanol that we project will be used to meet the RFS2 standards is presented in Tables 4.2.7 and 4.2.8.

**Table 4.2-7.**
**Cost of Unit Train Facilities to Facilitate the Transport of Ethanol**
**for the RFS2 Control Scenarios Relative to the AEO Reference Case**

| | Capital Cost (Million $) | | |
|---|---|---|---|
| | Low-Ethanol Scenario | Mid-Ethanol Scenario | High-Ethanol Scenario |
| Total Cost of Unit Train Facilities Needed for the Transport of Ethanol and Cellulosic Distillate Fuel/Renewable Diesel Fuel | 748 | 748 | 748 |
| Cost of Unit Train Facilities Attributed to Ethanol Transport | 238 | 434 | 748 |

**Table 4.2-8.**
**Cost of Unit Train Facilities to Facilitate the Transport of Ethanol for the RFS2 Control Scenarios Relative to the RFS1 Reference Case**

| | Capital Cost (Million $) | | |
|---|---|---|---|
| | Low-Ethanol Scenario | Mid-Ethanol Scenario | High-Ethanol Scenario |
| Total Cost of Unit Train Facilities Needed for the Transport of Ethanol and Cellulosic Distillate Fuel/Renewable Diesel Fuel | 838 | 838 | 838 |
| Cost of Unit Train Facilities Attributed to Ethanol Transport | 444 | 586 | 838 |

#### 4.2.1.1.3 Capital Cost of Manifest Rail Receipt Facilities for Ethanol

Our estimation of the number of manifest rail receipt facilities that will be needed to support the transport of the volumes of ethanol and cellulosic distillate fuel that we project will be used to meet the RFS2 standards is discussed in Section 1.6.4 of this RIA. The cost of these facilities was divided between ethanol and cellulosic distillate fuel/renewable diesel fuel in proportion to the fraction of the total ethanol + cellulosic distillate fuel/renewable diesel fuel volume. Based on input from companies familiar with the installation of manifest rail receipt facilities, we estimate that the total cost per facility will be $500 thousand.

Our projections of the total cost of the manifest rail receipt facilities and the portion that we attributed to the volume of ethanol that we project will be used to meet the RFS2 standards is presented in Tables 4.2.9 and 4.2.10.

**Table 4.2-9.**
**Cost of Manifest Rail Receipt Facilities for the RFS2 Control Scenarios Relative to the AEO Reference Case**

| | Capital Cost (Million $) | | |
|---|---|---|---|
| | Low-Ethanol Scenario | Mid-Ethanol Scenario | High-Ethanol Scenario |
| Total Cost of Manifest Rail Receipt Facilities Needed for the Transport of Ethanol and Cellulosic Distillate Fuel/Renewable Diesel Fuel | 21 | 21 | 21 |
| Cost of Manifest Rail Receipt Facilities Attributed to Ethanol Transport | 14 | 9 | 21 |

### Table 4.2-10.
### Cost of Manifest Rail Receipt Facilities for the RFS2 Control Scenarios Relative to the RFS1 Reference Case

| | Capital Cost (Million $) | | |
|---|---|---|---|
| | Low-Ethanol Scenario | Mid-Ethanol Scenario | High-Ethanol Scenario |
| Total Cost of Manifest Rail Receipt Facilities Needed for the Transport of Ethanol and Cellulosic Distillate Fuel/Renewable Diesel Fuel | 28 | 28 | 28 |
| Cost of Manifest Rail Receipt Facilities Attributed to Ethanol Transport | 13 | 8 | 28 |

#### 4.2.1.1.4 Ethanol Import Facility Capital Costs

Our estimation of the number of marine facilities that will be needed to support the receipt of the volume of imported ethanol that we project will be used to meet the RFS2 standards is discussed in Section 1.6.5 of this RIA. We estimate that a total of 30 port facilities will receive imported ethanol by 2022. Of these ports, 14 will need to accommodate ethanol receipts for the first time under the low-ethanol scenario, 15 under the mid-ethanol scenario, and 18 under the high ethanol scenario.

We believe that all such port facilities also serve as petroleum terminals. Thus, the cost of additional ethanol storage, ethanol blending equipment, and other miscellaneous equipment related to handling ethanol from the standpoint of terminal operations at such facilities is accounted for in the context of the costs at petroleum terminals (see Section 4.2.1.1.1 of this RIA). However, there will be additional costs at the port facilities which had not received ethanol in the past. Input from industry indicates that offloading large marine transport containers of ethanol requires significantly upgraded vapory recovery equipment. Based on this input, we estimated the cost of making the needed upgrades to vapor recovery equipment at 2.5 million dollars per facility. We further estimated miscellaneous costs associated with delivery of ethanol into storage tanks from marine vessels at 1 million dollars per facility. This is meant to include new piping, pumps, various other fittings, and a contingency cost. The actual cost could be significantly lower. Thus, we estimate that the total cost to prepare for delivery of ethanol at a port that had not received ethanol before at 3.5 million dollars per facility.

Based on the above, we estimate that the ethanol import port costs due to the importation of the additional volume of ethanol used to meet the RFS2 standards will be $49 million under the low-ethanol scenario, $52 million under the mid-ethanol scenario, and $63 million under the high-ethanol scenario. We assumed the same costs relative to both the RFS1 and AEO reference cases because we believe that the use of the incremental volume of ethanol imports attributed to meeting the RFS2 standards will take place after the RFS1 and AEO ethanol use volumes are met.

#### 4.2.1.1.5 Capital Costs of Barge Receipt Facilities for Intra-U.S Ethanol Transport

Our estimation of the number of barge receipt facilities for intra-U.S. biofuel shipment that will be need to support the transport of the volumes of ethanol and cellulosic distillate fuel that we project will be used to meet the RFS2 standards is discussed in Section 1.6.5 of this RIA. We estimate that 41 additional barge receipt facilities will receive shipments of ethanol and cellulosic distillate fuel/renewable diesel fuel relative to the AEO reference case and 53 relative to the RFS1 reference case. We used the same $3.5 million per facility cost that we estimated for the ethanol import facilities (see Section 4.2.1.1.4). The cost of these facilities was divided between ethanol and cellulosic distillate fuel/renewable diesel fuel in proportion to the fraction of the total ethanol + cellulosic distillate fuel/renewable diesel fuel volume.

Our projections of the total cost of the barge receipt facilities and the portion that we attributed to the volume of ethanol that we project will be used to meet the RFS2 standards is presented in Tables 4.2.11 and 4.2.12.

**Table 4.2-11.**
**Cost of Barge Receipt Facilities**
**for the RFS2 Control Scenarios Relative to the AEO Reference Case**

| | Capital Cost (Million $) | | |
|---|---|---|---|
| | Low-Ethanol Scenario | Mid-Ethanol Scenario | High-Ethanol Scenario |
| Total Cost of Barge Receipt Facilities Needed for the Transport of Ethanol and Cellulosic Distillate Fuel/Renewable Diesel Fuel | 143 | 143 | 143 |
| Cost of Barge Receipt Facilities Attributed to Ethanol Transport | 76 | 100 | 143 |

**Table 4.2-12.**
**Cost of Barge Receipt Facilities**
**for the RFS2 Control Scenarios Relative to the RFS1 Reference Case**

| | Capital Cost (Million $) | | |
|---|---|---|---|
| | Low-Ethanol Scenario | Mid-Ethanol Scenario | High-Ethanol Scenario |
| Total Cost of Barge Receipt Facilities Needed for the Transport of Ethanol and Cellulosic Distillate Fuel/Renewable Diesel Fuel | 185 | 185 | 185 |
| Cost of Barge Receipt Facilities Attributed to Ethanol Transport | 98 | 129 | 185 |

### 4.2.1.1.6 Ethanol Rail Car Capital Costs

Our estimation of the number of rail cars needed to transport the additional volume of ethanol that we project will be used to meet the RFS2 standards is discussed in Section 1.6.4 of this RIA. Based on input from rail car manufactures, we estimate that the cost of a new 30,000 gallon rail car suitable for ethanol service is $90 thousand. The cost of the additional ethanol rail cars needed under the 3 control scenarios relative to the 2 reference cases is presented in Tables 4.2-13 and 4.2-14.

**Table 4.2-13.**
**Cost of Additional Ethanol Rail Cars**
**for the RFS2 Control Scenarios Relative to the AEO Reference Case**

| | Low-Ethanol Scenario | Mid-Ethanol Scenario | High-Ethanol Scenario |
|---|---|---|---|
| Number of Additional Rail Cars | 4,050 | 8,450 | 18,870 |
| Rail Car Cost ($Million) | $365 | $760 | $1,699 |

**Table 4.2-14.**
**Cost of Additional Ethanol Rail Cars**
**for the RFS2 Control Scenarios Relative to the RFS1 Reference Case**

| | Low-Ethanol Scenario | Mid-Ethanol Scenario | High-Ethanol Scenario |
|---|---|---|---|
| Number of Additional Rail Cars | 9,820 | 14,210 | 24,639 |
| Rail Car Cost ($Million) | $884 | $1,279 | $2,218 |

### 4.2.1.1.7 Ethanol Barge Capital Costs

Our estimation of the number of barges needed for intra-U.S. transport of the additional volume of ethanol that we project will be used to meet the RFS2 standards is discussed in Section 1.6.5 of this RIA. Based on input from fuel barge manufactures, we estimate that the cost of a new 10,000 barrel barge suitable for ethanol service is $1.4 million. The cost of the additional ethanol barges needed under the 3 control scenarios relative to the 2 reference cases is presented in Tables 4.2-15 and 4.2-16.

**Table 4.2-15.**
**Cost of Additional Ethanol Barges**
**for the RFS2 Control Scenarios Relative to the AEO Reference Case**

| | Low-Ethanol Scenario | Mid-Ethanol Scenario | High-Ethanol Scenario |
|---|---|---|---|
| Number of Additional Barges | 16 | 32 | 73 |
| Cost of Barges ($Million) | $22 | $45 | $101 |

**Table 4.2-16.**
**Cost of Additional Ethanol Barges**
**for the RFS2 Control Scenarios Relative to the RFS1 Reference Case**

| | Low-Ethanol Scenario | Mid-Ethanol Scenario | High-Ethanol Scenario |
|---|---|---|---|
| Number of Additional Barges | 38 | 55 | 95 |
| Cost of Barges ($Million) | $53 | $76 | $133 |

#### 4.2.1.1.8 Ethanol Tank Truck Capital Costs

Our estimation of the number of tank trucks needed to transport the additional volume of ethanol that we project will be used to meet the RFS2 standards is discussed in Section 1.6.6 of this RIA. Based on input from ethanol tank truck manufactures, we estimate that the cost of a new 8,000 gallon tank truck suitable for ethanol service is $180 thousand. The cost of the additional ethanol tank trucks needed under the 3 control scenarios relative to the 2 reference cases is presented in Tables 4.2-17 and 4.2-18.

**Table 4.2-17.**
**Cost of Additional Ethanol Tank Trucks**
**for the RFS2 Control Scenarios Relative to the AEO Reference Case**

| | Low-Ethanol Scenario | Mid-Ethanol Scenario | High-Ethanol Scenario |
|---|---|---|---|
| Number of Additional Tank Trucks | 230 | 480 | 1,080 |
| Cost of Tank Trucks ($Million) | $42 | $87 | $194 |

**Table 4.2-18.**
**Cost of Additional Ethanol Tank Trucks**
**for the RFS2 Control Scenarios Relative to the RFS1 Reference Case**

| | Low-Ethanol Scenario | Mid-Ethanol Scenario | High-Ethanol Scenario |
|---|---|---|---|
| Number of Additional Tank Trucks | 590 | 860 | 1,490 |
| Cost of Tank Trucks ($Million) | $107 | $154 | $268 |

#### 4.2.1.1.9 E85 Retail Facility Costs

Our estimates of the number of additional E85 retail facilities and the number of E85 refueling positions needed at such facilities to enable the use of the volumes of E85 that we project will be used to meet the RFS2 standards under the 3 control scenarios is contained in Section 1.6.9 of this RIA. Our estimates of the additional E85 refueling infrastructure that will be needed relative to the 2 reference cases are presented in Table 4.2-19 and 4.2-20.

**Table 4.2.19.**
**Additional E85 Retail Facilities Needed by 2022 to Support the Projected Increase in E85 use under the RFS2 Control Scenarios Relative to the RFS1 Reference Case**

| | Low-Ethanol Scenario | Mid-Ethanol Scenario | High-Ethanol Scenario |
|---|---|---|---|
| New E85 Installation with 1 Dispenser | 14,967 | 10,923 | 0 |
| New E85 Installation with 2 Dispensers | 0 | 12,133 | 0 |
| New E85 Installation with 3 Dispensers | 0 | 0 | 27,099 |
| Addition of 2 Dispensers to Retail Facility that had 1 Dispenser | 0 | 0 | 1,210 |

**Table 4.2.20.**
**Additional E85 Retail Facilities Needed by 2022 to Support the Projected Increase in E85 use under the RFS2 Control Scenarios Relative to the AEO Reference Case**

| | Low-Ethanol Scenario | Mid-Ethanol Scenario | High-Ethanol Scenario |
|---|---|---|---|
| New E85 Installation with 1 Dispenser | 11,677 | 7,633 | 0 |
| New E85 Installation with 2 Dispensers | 0 | 12,133 | 0 |
| New E85 Installation with 3 Dispensers | 0 | 0 | 23,809 |
| Addition of 2 Dispensers to Retail Facility that had 1 Dispenser | 0 | 0 | 4,500 |

The following estimates regarding the cost of E85 compatible retail equipment are based on input from gasoline retailers and other parties with experience in the requirements and costs associated with installing E85 retail equipment. The total cost of installing a two nozzle E85 dispenser is estimated at $23,000. This is composed of $17,000 for the dispenser itself, $750 for hanging hardware, $950 for refueling island hardware, $3,000 for installation, and a $1,300 contingency cost. Hanging hardware costs are composed of $310 for 2 nozzles, $135 for 2 breakaway connections, $135 for 2 swivel connections, and $170 for 2 hoses. Refueling island hardware costs are composed of $450 for the dispenser island, $250 for an island sump pump, and $250 for bumper posts. Installation costs are composed of $1,500 for concrete removal and replacement, and $1,500 for wiring and piping.

The cost of automatic tank level gauging equipment is estimated at $6,500. It is estimated that 65% of retailers will install automatic tank gauging (ATG) equipment and the remainder will rely on manual means of determining the amount of fuel remaining in their underground storage tank. Thus, the average cost per facility will be $4,225 for ATG equipment. We estimate the cost of installing a canopy addition to provide cover for an additional dispenser at $15,000. We estimated that only 10% of facilities will need to install additional canopy coverage in order to accommodate the new E85 retail dispenser. Thus, the average canopy cost per facility is estimated at $1,500. The cost of installing a new 15,000 underground E85 storage tank is estimated at $102,000. The cost of connecting the tank to the dispenser(s) is included in this cost along with other miscellaneous storage tank related costs. In the NPRM, we estimated that an 8,000 gallon storage tank would be used at E85 retail facilities. We increased the size to 15,000 based on industry comments that the added storage volume will be needed to keep pace with fuel throughput without necessitating an overly-frequent fuel delivery schedule. The use of a 15,000 gallon storage tank will also allow the delivery of a full 8,000 gallon tank truck at a single retail facility. Input from fuel retailers indicates that there typically is at least 15,000 gallons of gasoline storage at current retail facilities. Based on the above, the cost of an E85 installation with one dispenser is estimated at $131 thousand, the cost of for a new E85 installation with 2 dispensers is estimated at $154 thousand, and the cost of a new E85 installation with 3 dispensers is estimated at $177 thousand. The cost of upgrading an existing E85 facility with a single dispenser to add 2 additional dispensers is estimated at $130 thousand.

Our E85 retail facility cost estimates are presented in Table 4.2-21. These estimates are based on the above E85 equipment cost estimates and the estimated facility requirements detailed in Tables 4.2-19 and 4.2-20.

**Table 4.2-21.**
**Cost of the Additional E85 Retail Facilities Needed by 2022**
**to Support the Projected Increase in E85 use under the RFS2 Control Scenarios**

| | E85 Capital Costs ($Billion) | | |
|---|---|---|---|
| | Low-Ethanol Scenario | Mid-Ethanol Scenario | High-Ethanol Scenario |
| Relative to the AEO 2007 Reference Case | 1.526 | 2.863 | 4.893 |
| Relative to the RFS1 Reference Case | 1.956 | 3.293 | 4.973 |

#### 4.2.1.1.10 Potential Costs of Supplying Special Blendstocks at Petroleum Terminals for E85

As discussed in Section 1.6.8 of this RIA, special blendstocks may need to be supplied to terminals to facilitate the manufacture of E85 which meets ASTM International minimum volatility specifications. To evaluate the potential impacts to the fuel distribution system if this is the case, we assumed that butane would be used as the special blendstock and that it would be blended into gasoline before being blended with denatured ethanol to produce E85. As such, we estimated the potential costs associated with automated inline butane blending systems, butane storage tanks, tank trucks, railcars, transloading facilities, and other facility changes needed for butane blending into E85. These costs are based upon discussions with industry representatives.

We assume that butane would be transported by tank truck and/or railcar from petroleum refineries to E85-producing petroleum terminals and stored until blended into a final product. Of the 1,063 terminals identified in our analysis, two-thirds (709) are assumed to blend E85. All of these terminals are assumed to require butane blending equipment. Our cost estimates assumed that twenty-five percent (177) of these terminals will receive butane via 31,500 gallon railcar and the remaining seventy-five percent (532) will receive butane via 8,200 gallon tank truck. Of the 177 terminals that receive butane via railcar, fifty-percent are assumed to directly off-load butane to tank storage for eventual blending into E85. The other fifty-percent of the terminals which received butane via railcar are assumed to transload the butane from railcars to tank trucks for final delivery to terminals which store butane for eventual blending into E85.

The blending of butane into E85 requires petroleum terminals to have on-site butane blending equipment. In developing our cost estimates, we assume that each terminal which blends E85 uses an automated, in-line butane blending system and two 60,000 gallon butane storage tanks. The cost of an in-line butane blending systems is assumed to be $1.5 million per unit. The cost each 60,000 gallon butane storage tank is assumed to be $150,000. Transloading equipment is assumed to cost $500,000 per unit.

Transport cost estimates were based upon the ORNL transport analysis discussed in Section 1.6.3. In that analysis, the cost of freight rail transport was assumed to average $0.12 per ton-mile. The cost of truck transport was assumed to average $0.14 per ton-mile. Average round trip distance is assumed to be 1,200 miles for railcars and 300 miles for tank trucks. Travel speed estimates are truck 35 mph and railcar 10 mph with roundtrip times being approximately 8 hours for trucks and 5 days for railcars. Each tank truck is assumed to cost $150,000 and each railcar is assumed to cost $135,000.

Estimates of the number of tank trucks and railcars required to deliver butane appears by low, medium, and high volume cases in Table 4.2-22 and a summary of cost estimates for the three volume cases appears in Table 4.2-23.

**Table 4.2-22.**
**Estimated Number of Tank Trucks and Rail Cars Needed for Shipment of Butane under the RFS2 Control Scenarios**

| | Number of Tank Trucks and Rail Cars Needed to Transport Butane | | |
|---|---|---|---|
| | Low-Ethanol Scenario | Mid-Ethanol Scenario | High-Ethanol Scenario |
| Tank Truck (8,200 gallons) | 2,165 | 3,280 | 5,530 |
| Railcar (31,500 gallons) | 236 | 358 | 602 |

### Table 4.2-23.
### Summary of Potential Costs to Provide Butane for E85 Blending under the RFS2 Control Scenarios

| | Freight Costs | Capital Costs |
|---|---|---|
| Low-Ethanol Scenario | $16 million | $357 million |
| Mid-Ethanol Scenario | $24 million | $911 million |
| High-Ethanol Scenario | $40 million | $927 million |

#### 4.2.1.2 Ethanol Freight Costs

Our estimates of ethanol freight costs are based on a study conducted by Oakridge National Laboratories (ORNL).[1162] The ORNL analysis contains detailed projections of which transportation modes and combination of modes (e.g. unit train to barge) are best suited for delivery of ethanol to specific markets considering ethanol source and end use locations, the current configuration and projected evolution of the distribution system, and cost considerations for the different transportation modes. The NPRM analysis assumed that all biofuel volumes other than biodiesel would be ethanol. For this FRM, we analyzed three scenarios under which varying volumes of cellulosic distillate fuel take the place of ethanol production volumes to meet the RFS2 standards. However, due to the timing of the various analyses for the FRM, the NPRM projections of the location of ethanol production facilities and end use areas contained in the NPRM had to be used as the inputs into the ORNL analysis.[JJJJJJJJJJ] Therefore, our use of the ORNL analysis to evaluate the freight costs for the final rule assumes that cellulosic distillate production plants will take the place of some of the ethanol production plants projected in the NPRM. It further assumes that cellulosic distillate fuel use will coincide with the ethanol end-use areas projected in the NPRM and that both fuels will be transported by the same means.

We estimated the freight costs under the FRM control scenarios by totaling the cellulosic distillate/renewable diesel fuel and ethanol volume under each scenario and interpolating between the freight costs projected by ORNL for 2 NPRM ethanol volume scenarios. This approach provides for the economy of scale in biofuel freight costs with increased volume. Based on this approach, we estimate that ethanol freight costs will be 12 cents per gallon (cpg) under the high-ethanol scenario and 13 cpg under the low-ethanol and mid-ethanol scenarios. Our use of the ORNL freight cost estimates to derive the freight FRM freight cost estimates is illustrated in Table 4.2-24.

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[JJJJJJJJJJ] The ORNL final report contains maps of projected ethanol production locations and end use areas.

### Table 4.2-24.
### Interpolation of FRM Ethanol and Cellulosic Distillate Fuel/Renewable Diesel Fuel Freight Costs from ORNL Freight Cost Estimates for NPRM Ethanol Volume Scenarios

| | Volume of Ethanol, Cellulosic Distillate Fuel, and Renewable Diesel Fuel (BGal/yr in 2022) | Freight Cost (cpg) |
|---|---|---|
| NPRM Control Scenario | 34.14 | 12.2<br>(ORNL estimate) |
| FRM High-Ethanol Scenario | 33.24 | 12<br>(Interpolation) |
| FRM Mid-Ethanol Scenario | 28.68 | 13<br>(Interpolation) |
| FRM Low Ethanol Scenario | 26.75 | 13<br>(Interpolation) |
| AEO 2007 Reference Case | 13.18 | 15.3<br>(ORNL estimate) |

### 4.2.2 Cellulosic Distillate Fuel Distribution Costs

As discussed in the following sections, we estimate that the total capital costs in the U.S to support distribution of the additional volume of cellulosic distillate fuel/renewable diesel fuel that will be used in to meet the RFS2 standards under the primary mid-ethanol scenario will be 1,392 billion dollars by 2022 relative to the AEO 2007 reference case. When amortized, this translates to 2 cents per gallon of additional cellulosic distillate fuel/renewable fuel attributed to the RFS2 standards. Amortization of capital costs was done over 15 years at a 7% annual cost of capital except in the case of the cost of tank trucks where a 10 year amortization schedule was used. Under the mid-ethanol primary scenario, we project that 6.7 BGY of cellulosic distillate fuel/renewable diesel fuel will be used by 2022. Cellulosic distillate fuel/renewable diesel fuel freight costs are estimated to be 13 cents per gallon on a national average basis. Thus, we estimate that total cellulosic distillate fuel/renewable diesel fuel distribution costs will be 15 cents per gallon of cellulosic distillate fuel/renewable diesel fuel that we project will be used to meet the RFS2 standards.[KKKKKKKKKK]

The cellulosic distillate fuel/renewable diesel fuel distribution capital and freight costs for all the control scenarios relative to the 2 reference cases that we evaluated in this FRM is summarized in Table 4.2-25. The itemized cellulosic distillate fuel/renewable diesel fuel capital costs are presented in Table 4.2-26 relative to the AEO 2007 reference case, and in Table 4.2-27 relative to the RFS1 reference case. The way in which we estimated these costs is detailed in the following sections. As discussed in the following sections, some biofuel infrastructure assets

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[KKKKKKKKKK] As noted previously, we chose not to subtract the distribution costs for the petroleum-based fuels that will be displaced by the use of biofuels from our estimated biofuel distribution costs. We believe that the freight costs to ship petroleum-based fuels to the terminal are approximately 4 cents per gallon. If we were to subtract these costs from the estimated cellulosic distillate fuel/renewable diesel fuel distribution costs under the mid-ethanol scenario relative to the AEO 2007 reference case, the result would be 11 cents per gallon.

such as unit train receipt facilities are used to distribute both cellulosic distillate fuel/renewable diesel fuel and ethanol. We attributed a fraction of the capital costs for such facilities to either cellulosic distillate fuel/renewable diesel fuel or ethanol in proportion to the fraction of the total additional volume of these fuels that we project will be used to meet the RFS2 standards relative to the reference case. This approach results in a slight difference in the capital costs under the 2 reference case despite the fact that the incremental volume of cellulosic distillate/renewable diesel fuel used to meet the RFS2 standards is the same under both reference cases.

**Table 4.2-25.**
**Summary of Estimated Cellulosic Distillate Fuel/Renewable Diesel Fuel Distribution Capital and Freight Costs under the RFS2 Control Scenarios Relative to the Reference Cases**

| | Low-Ethanol Scenario | | Mid-Ethanol Scenario | | High-Ethanol Scenario | |
|---|---|---|---|---|---|---|
| | RFS1 Reference | AEO Reference | RFS1 Reference | AEO Reference | RFS1 Reference | AEO Reference |
| Billion $ Capital | 1,999 | 2,036 | 1,375 | 1,392 | NA | NA |
| Capital Costs (cpg) | 2 | 2 | 2 | 2 | NA | NA |
| Freight Costs (cpg) | 13 | 13 | 13 | 13 | NA | NA |
| Total Distribution Costs (cpg) | 16 | 16 | 15 | 15 | NA | NA |

### Table 4.2-26.
### Summary of Estimated Cellulosic Distillate Fuel/Renewable Diesel Fuel Distribution Capital Costs under the RFS2 Control Scenarios
### Relative to the AEO 2007 Reference Case

| | Capital Cost (Million $) | | |
|---|---|---|---|
| | Low-Ethanol Scenario | Mid-Ethanol Scenario | High-Ethanol Scenario |
| Rail Cars | 784 | 552 | NA |
| Barges | 47 | 33 | NA |
| Tank Trucks | 90 | 63 | NA |
| Storage Tanks at Petroleum Terminals | 218 | 154 | NA |
| Blending and other Miscellaneous Equipment at Petroleum Terminals | 304 | 223 | NA |
| Unit Train Receipt Facilities | 511 | 315 | NA |
| Manifest Rail Receipt Facilities | 15 | 9 | NA |
| Marine Receipt Facilities for Inta-U.S. Transport | 67 | 43 | NA |
| Total (Million $) | 2,036 | 1,392 | NA |
| Total (cpg) | 2 | 2 | NA |

### Table 4.2-27.
### Summary of Estimated Cellulosic Distillate Fuel/Renewable Diesel Fuel Distribution Capital Costs under the RFS1 Reference Case

| | Capital Cost (Million $) | | |
|---|---|---|---|
| | Low-Ethanol Scenario | Mid-Ethanol Scenario | High-Ethanol Scenario |
| Rail Cars | 784 | 552 | NA |
| Barges | 47 | 33 | NA |
| Tank Trucks | 95 | 67 | NA |
| Storage Tanks at Petroleum Terminals | 218 | 154 | NA |
| Blending and other Miscellaneous Equipment at Petroleum Terminals | 361 | 252 | NA |
| Unit Train Receipt Facilities | 394 | 253 | NA |
| Manifest Rail Receipt Facilities | 13 | 8 | NA |
| Marine Receipt Facilities for Inta-U.S. Transport | 87 | 56 | NA |
| Total (Million $) | 1,999 | 1,375 | NA |
| Total (cpg) | 2 | 2 | NA |

### 4.2.2.1 Cellulosic Distillate Fuel Distribution Capital Costs

#### 4.2.2.1.2 Petroleum Terminal Cellulosic Distillate Fuel/Renewable Diesel Fuel Distribution Capital Costs

The terminal facility modifications needed to support the use of the volume of cellulosic diesel fuel/renewable diesel fuel that we project will be used to meet the RFS2 standards are discussed in Section 1.6.7. A summary of the costs associated with these modifications is detailed in Tables 4.2-28 and 4.2-29. The estimated costs vary depending on the reference case considered because of the way we attributed the cost of tank truck unloading facilities (which are used to handle both ethanol and cellulosic distillate fuel/renewable diesel fuel) to either ethanol or cellulosic distillate fuel/renewable diesel fuel. The cost of such facilities was divided between ethanol and cellulosic distillate fuel/renewable diesel fuel in proportion to the fraction of the total ethanol + cellulosic distillate fuel/renewable diesel fuel volume.

**Table 4.2-28.**
**Cellulosic Distillate Fuel/Renewable Diesel Fuel Associated Petroleum Terminal Costs under the RFS2 Control Scenarios Relative to the AEO Reference Case**

| | Capital Cost (Million $) | | |
|---|---|---|---|
| | Low-Ethanol Scenario | Mid-Ethanol Scenario | High-Ethanol Scenario |
| Total Costs | 522 | 377 | NA |
| New Storage Tank Construction Costs | 218 | 154 | NA |
| Tank Truck Unloading Facilities | 65 | 55 | NA |
| Blending and Miscellaneous Fuel Handling Costs | 239 | 168 | NA |

**Table 4.2-29.**
**Cellulosic Distillate Fuel/Renewable Diesel Fuel Associated Petroleum Terminal Costs under the RFS2 Control Scenarios Relative to the RFS1 Reference Case**

| | Capital Cost (Million $) | | |
|---|---|---|---|
| | Low-Ethanol Scenario | Mid-Ethanol Scenario | High-Ethanol Scenario |
| Total Costs | 579 | 406 | NA |
| New Storage Tank Construction Costs | 218 | 154 | NA |
| Tank Truck Unloading Facilities | 122 | 84 | NA |
| Blending and Miscellaneous Fuel Handling Costs | 239 | 168 | NA |

The above cost estimates are based on the following. Input from terminal operators indicates that the cost of ethanol blending equipment is $310 thousand for E85-capable equipment. Input from companies that are familiar with the installation of ethanol truck unloading equipment at terminals indicates that the cost averages $500 thousand per facility. Input from terminal operators indicates that the cost of new diesel fuel storage tank construction is $35 per barrel for the size of tanks that are likely to be used. We used the above estimates regarding the costs of installing similar equipment for cellulosic distillate fuel/renewable diesel fuels.

### 4.2.2.1.3 Capital Cost of Unit Train Receipt Facilities for Cellulosic Distillate Fuel/Renewable Diesel fuel

Our estimation of the number of unit train receipt facilities that will be needed to support the transport of the volumes of ethanol and cellulosic distillate fuel/renewable diesel fuel that we project will be used to meet the RFS2 standards is discussed in Section 1.6.4 of this RIA. The cost of these facilities was divided between ethanol and cellulosic distillate fuel/renewable diesel fuel in proportion to the fraction of the total ethanol plus cellulosic distillate fuel/renewable diesel fuel volume. See Section 4.2.1.1.2 for additional discussion regarding the derivation of the total cost of unit train receipt facilities.

Our projections of the total cost of unit train receipt facilities and the portion that we attributed to the volume of cellulosic distillate fuel/renewable diesel fuel that we project will be used to meet the RFS2 standards is presented in Tables 4.2-30 and 4.2-31.

**Table 4.2-30.**
**Cost of Unit Train Facilities to Facilitate the Transport of Cellulosic Distillate Fuel/Renewable Diesel Fuel under the RFS2 Control Scenarios Relative to the AEO Reference Case**

| | Capital Cost (Million $) | | |
|---|---|---|---|
| | Low-Ethanol Scenario | Mid-Ethanol Scenario | High-Ethanol Scenario |
| Total Cost of Unit Train Facilities Needed for the Transport of Ethanol and Cellulosic Distillate Fuel/Renewable Diesel Fuel | 748 | 748 | 748 |
| Cost of Unit Train Facilities Attributed to Cellulosic Distillate Fuel/Renewable Diesel Fuel Transport | 394 | 253 | NA |

### Table 4.2-31.
### Cost of Unit Train Facilities to Facilitate the Transport of Cellulosic Distillate Fuel/Renewable Diesel Fuel under the RFS2 Control Scenarios Relative to the RFS1 Reference Case

| | Capital Cost (Million $) | | |
|---|---|---|---|
| | Low-Ethanol Scenario | Mid-Ethanol Scenario | High-Ethanol Scenario |
| Total Cost of Unit Train Facilities Needed for the Transport of Ethanol and Cellulosic Distillate Fuel/Renewable Diesel Fuel | 838 | 838 | 838 |
| Cost of Unit Train Facilities Attributed to Cellulosic Distillate Fuel/Renewable Diesel Fuel Transport | 511 | 315 | NA |

#### 4.2.2.1.4 Capital Cost of Manifest Rail Receipt Facilities for Cellulosic Distillate Fuel/Renewable Diesel Fuel

Our estimation of the number of manifest rail receipt facilities that will be needed to support the transport of the volumes of ethanol and cellulosic distillate fuel that we project will be used to meet the RFS2 standards is discussed in Section 1.6.4 of this RIA. The cost of these facilities was divided between ethanol and cellulosic distillate fuel/renewable diesel fuel in proportion to the fraction of the total ethanol plus cellulosic distillate fuel/renewable diesel fuel volume. See Section 4.2.1.1.2 for additional discussion regarding the derivation of the total cost of manifest rail receipt facilities.

Our projections of the total cost of the manifest rail receipt facilities and the portion that we attributed to the volume of cellulosic distillate fuel/renewable diesel fuel that we project will be used to meet the RFS2 standards is presented in Tables 4.2-32 and 4.2-33.

### Table 4.2-32.
### Cost of Manifest Rail Receipt Facilities under the RFS2 Control Scenarios Relative to the AEO Reference Case

| | Capital Cost (Million $) | | |
|---|---|---|---|
| | Low-Ethanol Scenario | Mid-Ethanol Scenario | High-Ethanol Scenario |
| Total Cost of Manifest Rail Receipt Facilities Needed for the Transport of Ethanol and Cellulosic Distillate Fuel/Renewable Diesel Fuel | 21 | 21 | 21 |
| Cost of Unit Train Facilities Attributed to Cellulosic Distillate Fuel/Renewable Diesel Fuel Transport | 14 | 9 | NA |

### Table 4.2-33.
### Cost of Manifest Rail Receipt Facilities under the RFS2 Control Scenarios Relative to the RFS1 Reference Case

| | Capital Cost (Million $) | | |
|---|---|---|---|
| | Low-Ethanol Scenario | Mid-Ethanol Scenario | High-Ethanol Scenario |
| Total Cost of Manifest Rail Receipt Facilities Needed for the Transport of Ethanol and Cellulosic Distillate Fuel/Renewable Diesel Fuel | 28 | 28 | 28 |
| Cost of Unit Train Facilities Attributed to Cellulosic Distillate Fuel/Renewable Diesel Fuel Transport | 13 | 8 | NA |

#### 4.2.2.1.5 Barge Receipt Facility Costs for Cellulosic Distillate Fuel/Renewable Diesel Fuel

Our estimation of the number of barge receipt facilities for intra-U.S. biofuel shipments that will be needed to support the transport of the volumes of ethanol and cellulosic distillate fuel/renewable diesel fuel that we project will be used to meet the RFS2 standards is discussed in Section 1.6.5 of this RIA. The cost of these facilities was divided between ethanol and cellulosic distillate fuel/renewable diesel fuel in proportion to the fraction of the total ethanol plus cellulosic distillate fuel/renewable diesel fuel volume.

Our projections of the total cost of the barge receipt facilities and the portion that we attributed to the volume of cellulosic distillate fuel/renewable diesel fuel that we project will be used to meet the RFS2 standards is presented in Tables 4.2-34 and 4.2-35. See Section 4.2.1.1.5 of this RIA for additional discussion of the derivation of these estimates.

## Table 4.2-34.
## Cost of Barge Receipt Facilities under the RFS2 Control Scenarios Relative to the AEO Reference Case

| | Capital Cost (Million $) | | |
|---|---|---|---|
| | Low-Ethanol Scenario | Mid-Ethanol Scenario | High-Ethanol Scenario |
| Total Cost of Barge Receipt Facilities Needed for the Transport of Ethanol and Cellulosic Distillate Fuel/Renewable Diesel Fuel | 143 | 143 | 143 |
| Cost of Barge Receipt Facilities Attributed to Cellulosic Distillate Fuel/Renewable Diesel Fuel Transport | 87 | 56 | NA |

### Table 4.2-35.
### Cost of Barge Receipt Facilities under the RFS2 Control Scenarios Relative to the RFS1 Reference Case

| | Capital Cost (Million $) | | |
|---|---|---|---|
| | Low-Ethanol Scenario | Mid-Ethanol Scenario | High-Ethanol Scenario |
| Total Cost of Barge Receipt Facilities Needed for the Transport of Ethanol and Cellulosic Distillate Fuel/Renewable Diesel Fuel | 185 | 185 | 185 |
| Cost of Barge Receipt Facilities Attributed to Cellulosic Distillate Fuel/Renewable Diesel Fuel Transport | 67 | 46 | NA |

#### 4.2.2.1.6 Cellulosic Distillate Fuel/Renewable Diesel Fuel Rail Car Capital Costs

Our estimation of the number of rail cars needed to transport the additional volume of cellulosic distillate fuel/renewable diesel fuel that we project will be used to meet the RFS2 standards is discussed in Section 1.6.4 of this RIA. Based on input from rail car manufactures, we estimate that the cost of a new 30,000 gallon rail car suitable for ethanol service is $90 thousand. We used this estimate as the cost of a rail car suitable for cellulosic distillate fuel/renewable diesel fuel service. This may tend to overstate the cost of such rail cars given that ethanol rail cars need to be constructed of ethanol tolerant materials. The cost of the additional cellulosic distillate fuel/renewable diesel fuel rail cars needed under the 3 control scenarios is presented in Table 4.2-36. Our estimate of the additional number of cellulosic distillate fuel/renewable diesel fuel rail cars needed to support meeting the RFS2 standards is the same relative to both reference cases.

### Table 4.2-36.
### Cost of Additional Cellulosic Distillate Fuel/Renewable Diesel Fuel Rail Cars under the RFS2 Control Scenarios

| | Low-Ethanol Scenario | Mid-Ethanol Scenario | High-Ethanol Scenario |
|---|---|---|---|
| Number of Additional Rail Cars | 8,710 | 6,130 | NA |
| Rail Car Cost ($Million) | $784 | $552 | NA |

#### 4.2.2.1.7 Cellulosic Distillate Fuel/Renewable Diesel Fuel Barge Capital Costs

Our estimation of the number of barges needed for intra-U.S. transport of the additional volume of cellulosic distillate fuel/renewable diesel fuel that we project will be used to meet the RFS2 standards is discussed in Section 1.6.5 of this RIA. Based on input from fuel barge manufactures, we estimate that the cost of a new 10,000 barrel barge suitable for ethanol service is $1.4 million. We used this estimate as the cost of a barge suitable for cellulosic distillate fuel/renewable diesel fuel service. This may tend to overstate the cost of such barges given that ethanol barges need to be constructed of ethanol tolerant materials. The cost of the additional cellulosic distillate fuel/renewable diesel fuel barges needed under the 3 control scenarios is presented in Table 4.2-37. Our estimate of the additional number of cellulosic distillate fuel/renewable diesel fuel barges needed to support meeting the RFS2 standards is the same relative to both reference cases.

**Table 4.2-37.**
**Cost of Additional Cellulosic Distillate Fuel/Renewable Diesel Fuel Barges under the RFS2 Control Scenarios**

| | Low-Ethanol Scenario | Mid-Ethanol Scenario | High-Ethanol Scenario |
|---|---|---|---|
| Number of Additional Barges | 33 | 24 | NA |
| Cost of Barges ($Million) | $47 | $33 | NA |

#### 4.2.2.1.8 Cellulosic Distillate Fuel/Renewable Diesel Fuel Tank Truck Capital Costs

Our estimation of the number of tank trucks needed to transport the additional volume of cellulosic distillate fuel/renewable diesel fuel that we project will be used to meet the RFS2 standards is discussed in Section 1.6.6 of this RIA. Based on input from ethanol tank truck manufactures, we estimate that the cost of a new 8,000 gallon tank truck suitable for ethanol service is $180 thousand. We used this estimate as the cost of a tank truck suitable for cellulosic distillate fuel/renewable diesel fuel service. This may tend to overstate the cost of such tank trucks given that ethanol tank trucks need to be constructed of ethanol tolerant materials. The cost of the additional cellulosic distillate fuel/renewable diesel fuel tank trucks needed under the 3 control scenarios is presented in Table 4.2-38. Our estimate of the additional number of cellulosic distillate fuel/renewable diesel fuel tank trucks needed to support meeting the RFS2 standards is the same relative to both reference cases.

### Table 4.2-38.
### Cost of Additional Cellulosic Distillate Fuel/Renewable Diesel Fuel Tank Trucks under the RFS2 Control Scenarios

| | Low-Ethanol Scenario | Mid-Ethanol Scenario | High-Ethanol Scenario |
|---|---|---|---|
| Number of Additional Tank Trucks | 500 | 350 | NA |
| Cost of Tank Trucks ($Million) | $90 | $63 | NA |

#### 4.2.2.2 Cellulosic Distillate Fuel Freight Costs

We used a study conducted by Oakridge National Laboratories (ORNL) to estimate ethanol and cellulosic distillate fuel/renewable diesel fuel freight costs. Refer to Section 4.2.1.2 of this RIA for a discussion of how these costs were derived. We estimate that cellulosic distillate fuel/renewable diesel fuel freight costs will be 13 cents per gallon under both the low-ethanol and mid-ethanol scenarios.

### 4.2.3 Biodiesel Distribution Costs

As discussed in the following sections, we estimate that the total capital costs in the U.S to support distribution of the additional volume of biodiesel that we project will be used to meet the RFS2 standards will be 1,141 billion dollars relative to the AEO 2007 reference case and 1,212 billion dollars relative to the RFS1 reference case.[LLLLLLLLLL] When amortized, this translates to 10 cents per gallon of additional biodiesel volume that we project will be used to meet the RFS2 standards relative to both reference cases. Amortization of capital costs was done over 15 years at a 7% annual cost of capital except in the case of the cost of tank trucks where a 10 year amortization schedule was used. We project that 1.67 BGY of biodiesel will be used by 2022 to meet the RFS2 standard volumes. Under the AEO reference case 380 BG/yr of biodiesel will be used by 2022. Under the RFS1 reference case, 300 BG/yr of biodiesel will be used by 2022. Thus, the additional amount of biodiesel that will be used by 2022 to meet the RFS2 standard volumes is 1,290 BG/yr relative to the AEO reference case and 1,370 BG/yr relative to the RFS1 reference case. Biodiesel freight costs are estimated to be 10 cents per gallon on a national average basis. Thus, we estimate that biodiesel distribution costs will be 20 cents per gallon of biodiesel that we project will be used to meet the RFS2 standards.[MMMMMMMMMM]

The biodiesel distribution capital and freight costs relative to the 2 reference cases that we evaluated in this FRM are summarized in Table 4.2-39. The itemized biodiesel capital costs are presented in Table 4.2-40. The way in which we estimated these costs is detailed in the following sections.

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[LLLLLLLLLL] Biodiesel distribution costs do not vary under the three control scenarios evaluated in this final rule.

[MMMMMMMMMM] As noted previously, we chose not to subtract the distribution costs for the petroleum-based fuels that will be displaced by the use of biofuels from our estimated biofuel distribution costs. We believe that the freight costs to ship petroleum-based fuels to the terminal are approximately 4 cents per gallon. If we were to subtract these costs from the estimated biodiesel distribution, the result would be 16 cents per gallon.

### Table 4.2-39.
### Summary of Estimated Biodiesel Capital and Freight Costs for the RFS2 Control Scenario Relative to the Reference Cases

| | RFS1 Reference | AEO Reference |
|---|---|---|
| Billion $ Capital | 1,212 | 1,141 |
| Capital Costs (cpg) | 10 | 10 |
| Freight Costs (cpg) | 10 | 10 |
| Total Distribution Costs (cpg) | 20 | 20 |

### Table 4.2-40.
### Summary of Estimated Biodiesel Distribution Capital Costs for the RFS2 Control Scenario Relative to the Reference Cases

| | Capital Costs (Million$) | |
|---|---|---|
| | RFS1 Reference | AEO Reference |
| Rail Cars | 111 | 105 |
| Barges | 53 | 50 |
| Tank Trucks | 25 | 24 |
| Storage Tanks at Petroleum Terminals | 411 | 387 |
| Blending and other Miscellaneous Equipment at Petroleum Terminals | 612 | 576 |
| Total (Million $) | 1,212 | 1,141 |
| Total (cpg) | 10 | 10 |

### 4.2.3.1 Capital Costs to Upgrade the Biodiesel Distribution System

#### 4.2.3.1.1 Petroleum Terminal Biodiesel Distribution Capital Costs

The terminal facility modifications needed to support the use of the volume of biodiesel that we project will be used to meet the RFS2 standards are discussed in Section 1.6.7. Total capital costs at terminals by 2022 are estimated at $963 million relative to the AEO reference case and $1,023 million relative to the RFS1 reference case.

We estimate that a total of 5.5 million barrels of new biodiesel storage will be needed at petroleum terminals to facilitate meeting the projected RFS2 biodiesel volume relative to the AEO reference case, and 5.9 million barrels relative to the RFS1 reference case. We assumed that all of the additional biodiesel storage will be satisfied by new construction. Based on information from industry, we estimate that the cost of constructing new biodiesel storage tanks would be 70 dollars per barrel of capacity. This is considerably higher than the 40 per barrel cost we estimated for construction of new ethanol tanks for two reasons. Biodiesel tanks need to be heated/insulated in colder climes and they tend to be of considerably smaller size compared to ethanol tanks. Both of these factors contribute significantly to the cost per barrel of constructing a new storage tank. We estimate that the total cost at petroleum terminals of new biodiesel storage tanks would be $387 million dollars relative to the AEO reference case and $411 million relative to the RFS1 reference case.

We projected that 600 additional petroleum terminals will need to install biodiesel blending equipment by 2022 to facilitate meeting the RFS2 biodiesel volume relative to the AEO reference case and 637 relative to the RFS1 reference case. Based on input from industry, we estimated that the cost of biodiesel blending equipment will be 400 thousand dollars per terminal. The cost of additional piping is estimated at 60,000 per terminal. Ancillary costs associated with receiving/blending/storing biodiesel are estimated at 500 thousand dollars per terminal.[NNNNNNNNNN] Based on the above, the cost of additional biodiesel blending and other miscellaneous biodiesel handling equipment at terminals is estimated at $576 million relative to the AEO reference case, and $612 million relative to the RFS1 reference case. Estimated equipment costs for handling biodiesel are higher than those for similar equipment designed to handle ethanol due to the need for insulated/heated equipment in colder climes.

#### 4.2.3.1.2 Biodiesel Rail Car Capital Costs

As discussed in Section 1.64 of this RIA, we estimate that an additional 1,060 rail cars will be needed by 2022 to facilitate transport of the volume of biodiesel that we project will be used to meet the RFS2 standards relative to the AEO reference case, and 1,120 relative to the RFS1 reference case. Based on input from industry, we estimate that the cost of a new biodiesel tank car of 25,600 gallon capacity is $99,000. The estimated cost for a biodiesel rail car is 10% higher than that of an ethanol rail car to accommodate the need for insulated/heated tanks in colder climes. Thus, we estimate that the cost of the biodiesel rail tanks cars needed by 2022 to facilitate transport of the volume of biodiesel that we project will be used to meet the RFS2

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[NNNNNNNNNN] This includes the installation of biodiesel truck receipt facilities, quality control testing equipment, and other ancillary equipment at terminals.

standards would be $105 million relative to the AEO reference case, and $111 million relative to the RFS1 reference case.

#### 4.2.3.1.3 Biodiesel Barge Capital Costs

As discussed in Section 1.65 of this RIA, we estimate that an additional 32 barges will be needed by 2022 to facilitate transport of the volume of biodiesel that we project will be used to meet the RFS2 standards relative to the AEO reference case, and 34 relative to the RFS1 reference case. Based on input from industry, we estimate that the cost of a new biodiesel barge of 10,000 bbl capacity is $1.54 million. The estimated cost for a biodiesel barge is 10% higher than that of an ethanol rail car to accommodate the need for insulated/heated storage compartments in colder climes. Thus, we estimate that the cost of the biodiesel barges needed by 2022 to facilitate transport of the volume of biodiesel that we project will be used to meet the RFS2 standards would be $49 million relative to the AEO reference case, and $52 million relative to the RFS1 reference case.

#### 4.2.3.1.4 Biodiesel Tank Truck Capital Costs

As discussed in Section 1.66 of this RIA, we estimate that an additional 120 tank trucks will be needed by 2022 to facilitate transport of the volume of biodiesel that we project will be used to meet the RFS2 standards relative to the AEO reference case, and 130 relative to the RFS1 reference case. Based on input from industry, we estimate that the cost of a new biodiesel tank truck of 8,000 gallon capacity is $198,000. This is based on an 110,000 dollar cost for the tractor and an 88,000 thousand dollar cost for the tank trailer. This estimate is 25% higher than the cost of a tank trailer designed to transport ethanol due to the need for an insulated/heated tank in colder climes. Based on the above, we estimate that the cost of the biodiesel tank trucks needed by 2022 to facilitate transport of the volume of biodiesel that we project will be used to meet the RFS2 standards would be $23 million relative to the AEO reference case, and $25 million relative to the RFS1 reference case.

### 4.2.3.2 Biodiesel Freight Costs

Our analysis of biodiesel freight costs for this FRM draws upon the analysis conducted for the NPRM. The NPRM analysis was based on a total biodiesel production volume of 810 million gallons by 2022 and was conducted relative to the AEO reference case under which 380 million gallons of biodiesel would be used. For the FRM, we are assuming that 1,670 million gallons of biodiesel would be used by 2022. The biodiesel capital cost analysis was conducted relative both the AEO and RFS1 reference cases. Under the RFS1 reference case 300 million gallons of biodiesel would be used by 2022 compared to the 380 million gallons under the AEO reference case. We believe that the difference between to the two reference cases is sufficiently small (80 million gallons per year by 2022) so that a single analysis of biodiesel freight costs conducted relative to the AEO reference case provides a reasonable estimate relative to both reference case. Hence, we used the results of our biodiesel freight cost analysis under the AEO reference case for the RFS1 reference case as well.

Our estimation of biodiesel freight costs for the NPRM was based on our evaluation of where biodiesel would be produced and the potential biodiesel demand centers. Our projections of where biodiesel would be produced and used under the NPRM analysis is contained in Section 1.8.2 of this RIA. Our projections of where biodiesel will be produced under the final rule (FRM) analysis are contained in Section 1.5.4 of this RIA. The NPRM estimate of where biodiesel would be used was used in our final rule analysis. Due to time constraints, we used a modified NPRM biodiesel freight cost analysis (which assumes the same production and demand centers used in the NPRM) to estimate biodiesel freight costs for this final rule. This analysis is described below. Our comparison of projected biodiesel production centers under the NPRM and FRM analyses relative to the projected demand centers indicates that the biodiesel transportation modes and distances are substantially similar. As a result, the freight cost estimates should be similar.

The distribution of biodiesel from production plants to petroleum terminals where it would be blended with diesel fuel is discussed in Section 1.6.2 of this RIA. Tank truck was the assumed method of shipment for distances of less than 300 miles. Where distances are longer than 300 miles, shipment by manifest rail was assumed to be the preferred option other than in cases on the East coast where there were apparent barge routes from production to demand centers. Biodiesel that could not be consumed in the state where it was produced to meet State level biodiesel mandates, demand for biodiesel use in heating oil, or other projected biodiesel use in diesel fuel was assumed to be shipped to market by manifest rail.[OOOOOOOOOO] A 1,000 mile shipping distance was selected to ensure that all biodiesel not used to satisfy a state mandate, otherwise used in state, or used for bio-heat could find a market.

Our estimates of the freight costs for shipping biodiesel by tank truck are based on the ethanol tank truck freight costs that we developed for the RFS1 final rule. These ethanol transport costs were increased by 10% to account for the increased cost associated with preventing fuel gelling during cold conditions. The cost of shipping biodiesel by truck when the trip (or multiple trips) could be completed in a day was estimated to range from 7 to 8 cents per gallon. Some long truck transports were assumed to be necessary (up to 300 miles), where a round trip could not be completed in a single day. In such cases, the need for an overnight layover was assumed to add 120 dollars to shipping costs, resulting in an estimated 9.5 cents per gallon freight cost.

Our estimate of the cost of shipping biodiesel by manifest rail cars is based on publicly available biodiesel freight tariff information from BNSF railway from February 2008.[1163] Specific tariff information was not available for source/destinations needed for our analysis. A minimum cost of 9 cents per gallon was assumed to accommodate loading, unloading, and rail car lease costs. Based on the BNSF tariff information, we estimated that every 100 miles of additional shipment by manifest rail car beyond 600 miles adds 1.4 cents per gallon to shipping cost. Thus, for the assumed 1,000 mile shipping distance for biodiesel used to meet miscellaneous demand (i.e. not used to meet state mandates or for bioheat) the cost to ship by manifest rail car was estimated at 15 cents per gallon. Barge shipping costs were assumed to be comparable to the cost of shipping by manifest rail. This will tend to overstate barge shipping

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[OOOOOOOOOO] Biodiesel is projected to be blended into most heating oil used in the Northeast by 2022. The blended product is commonly referred to as bioheat.

costs, since we understand that barge freight costs tend to be significantly less than rail freight costs. However, given the small fraction of biodiesel is projected to me moved by barge, this will have only a minimal effect on our overall estimation of biodiesel freight costs. Shipping distances were estimated based on a review of biodiesel production plant locations, demand centers, and the rail/barge transportation net.[PPPPPPPPPP]

Considering the location of biodiesel plants and biodiesel demand centers, 86% of biodiesel was projected to be shipped by truck, 13% was estimated to be shipped by manifest rail car, and 1% was estimated to be shipped by barge. We project that approximately 44% of the biodiesel production volume in 2022 would be used in the state where it was produced to meet state mandates, satisfy the demand for bioheat, or to meet other in-state miscellaneous demand. The average cost of shipping this volume by tank truck is estimated to average 8 cents per gallon. Approximately 3% of biodiesel production volume is estimated to be shipped out-of-state by manifest rail car to meet miscellaneous biodiesel demand at an average freight cost of 16 cents per gallon. Approximately 54% of biodiesel production is projected to be shipped out of state to satisfy state mandates or bioheat demand which could not be satisfied with in-state production. We assigned portions of the production volumes from states that had already satisfied this demand to meet this demand in other states based on minimizing overall shipping distances (and costs).

A freight cost estimate was derived based on the fraction of the volumes that would be shipped by each mode and the freight cost for each mode used given the shipping distance. On average the cost of shipping biodiesel from out-of-state to satisfy state biodiesel mandates or the demand for bioheat is estimated at 10 cents per gallon. By weighting the biodiesel volumes used to satisfy the three demand categories by the respective freight cost to ship that volume we arrived at a national average biodiesel freight cost estimate of 10 cents per gallon. Biodiesel freight costs are summarized in Table 4.2-41.

**Table 4.2-41.**
**Estimated Biodiesel Freight Costs for the RFS2 Control Case**

| Biodiesel Demand Category | Fraction of Biodiesel Production | Freight Cost (cpg) |
|---|---|---|
| Shipped In-State to Satisfy In-State Demand | 43% | 8 |
| Shipped Out-of-State to Satisfy State Mandates and Demand for Bioheat | 54% | 11 |
| Shipped Out-of-State to Satisfy Miscellaneous Demand | 3% | 16 |
| Total (National Average) | 100% | 10 |

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[PPPPPPPPPP] See Section 1.8.2 of this RIA.

### 4.2.4 Potential Fuel Retail Costs to Facilitate the Use of Mid-Level Ethanol Blends

As discussed in Section 1.6.10 of this RIA, our preliminary projections regarding the potential costs to the fuel distribution system are based on the premise that the facility changes needed would be limited to retail facilities. There may be additional costs upstream of retail facilities if separate gasoline blendstocks are needed to blend E10 and E15.

Testing is still underway regarding what changes might be needed to retail fuel storage and dispensing equipment originally designed to handle E10 to ensure its compatibility for an E15 blend. Thus there is considerable uncertainty regarding the potential costs. Ideally, E15 could be dispensed and stored in existing retail equipment with no physical modifications. However, it seems most prudent to assume that the potential changes might range from the replacement of hanging hardware (hoses attached to the dispenser and the nozzles), to the replacement of dispensers with E85 compatible equipment, and/or to the modification to underground piping which connects the dispenser to the underground storage tanks. There may also be the need to replace the underground storage tanks themselves at some facilities. Some newer facilities might need to make fewer changes, while older facilities may require more extensive modifications.

We evaluated 3 cost scenarios regarding the potential modifications needed to ensure the compatibility of current retail fuel storage and dispensing facilities to handle E15. Under the first scenario, each retail facility would need to replace only the hanging hardware on the pumps which dispense gasoline. The National Association of Convenience Stores (NACS) estimates that there are 3.9 gasoline refueling dispensers on average at retail facilities.[1164] The National Petroleum News (NPN) estimates that there were 161,768 retail facilities in the U.S. in 2008.[1165] Thus, we estimate that there are approximately 631,000 gasoline dispensers at retail facilities. Information from fuel retailers indicates that the cost of hanging hardware that is compatible with E85 is $750 for the 2 hoses and nozzles needed for a single dispenser. We choose to use the cost for E85-compatible hardware because there is no information on whether there may be lower costs for E15-compatible equipment.[QQQQQQQQQQ] We assumed a $25 installation cost per dispenser. Assuming that the hanging hardware on all gasoline dispensers would need to replaced, the resulting cost would be $127 million. However, a significant fraction of this cost might be deferred to the extent that hanging hardware could be replaced on a timetable that is consistent with the normal maintenance schedule as the number of E15 facilities ramps up. Information from fuel retailers indicates that hanging hardware is typically replaced every 3 to 5 years.

Under the second scenario, the wetted components inside fuel dispensers would need to be replaced in addition to the hanging hardware.[RRRRRRRRRR] Information from fuel dispenser manufactures indicates that the cost of the wetted fuel dispenser components is approximately

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[QQQQQQQQQQ] Underwriters Laboratories has separate certification for E10, E25, and E85 retail dispensing equipment. No equipment has currently been certified for E25 or E85 use. However, there is considerable experience regarding the equipment suitable for E85 service.

[RRRRRRRRRR] The wetted components refers to the components inside the fuel dispenser which come into contact with the fuel.

$10,000. We assumed a $1,000 installation cost per dispenser. Fuel dispenser equipment installers indicated that the replacement of the wetted components in a fuel dispenser is not standard practice, and there may be logistical and administrative difficulties that would need to be overcome. The cost would be $6.940 billion, if assume that the wetted components in all fuel dispensers would need to replaced. Adding the cost of replacing the wetted dispenser components to the cost of replacing the hanging hardware, results in a total cost estimate of $7.067 billion.

Under the third scenario, a fraction of retail facilities would need to break concrete to modify underground components such as the piping between dispensers and storage tanks and the joints between piping and other underground components. This is the most speculative scenario given that the costs of modifying underground components could vary greatly depending on the extent of the modifications that might be needed. We assumed an average cost of $25,000 per facility to make the changes needed to underground facilities. We believe that this is a low-end estimate given that the cost of modifications to underground retail fuel storage facilities can escalate quickly. We assumed that 50% of all retail facilities would need to make such changes for a total cost of $2.022 billion. Adding in the cost of replacing the wetted dispenser components and cost of replacing the hanging hardware, results in a total cost estimate of $9.089 billion.

These cost estimates could be altered significantly as a result of the findings of the test programs currently underway regarding the compatibility of existing fuel retail equipment with E15. As discussed in Section 1.6.10 of this RIA, there may be difficulties in identifying what changes are needed at some retail facilities due to a lack of records on the type of equipment currently installed. This may limit the ability to make such retail facilities E15 compatible.

## 4.3 Reduced U.S. Refining Demand

As renewable and alternative fuel use increases, the volume of petroleum-based products, such has gasoline and diesel fuel produced by U.S. refineries, would decrease. This reduction in finished refinery petroleum products results in reduced refinery industry costs. The reduced costs would essentially be the volume of fuel displaced multiplied by the cost for producing the fuel. There is also a reduction in capital costs as investment in new refinery capacity is displaced by investments in renewable and alternative fuels capacity.

Although we conducted refinery modeling for estimating the cost of blending ethanol (see Section 4.4), we did not rely on the refinery model results for estimating the volume of displaced petroleum as other economic factors also come into play. Instead we conducted an energy balance around the increased use of renewable fuels, estimating the energy-equivalent volume of gasoline or diesel fuel displaced. This allowed us to more easily apply our best estimates for how much of the petroleum would displace imports of finished products versus crude oil for our energy security analysis which is discussed in Section 5.2 of the RIA.

As part of this petroleum displacement analysis, we accounted for the change in petroleum demanded by upstream processes related to additional production of the renewable fuels as well as reduced production of petroleum fuels. For example, growing corn used for ethanol production requires the use of diesel fuel in tractors, which reduces the volume of petroleum displaced by the ethanol. Similarly, the refining of crude oil uses by-product hydrocarbons for heating within the refinery, therefore the overall effect of reduced gasoline and diesel fuel consumption is actually greater because of the additional upstream effect. We used the lifecycle petroleum demand estimates provided for in the GREET model to account for the upstream consumption of petroleum for each of the renewable and alternative fuels, as well as for gasoline and diesel fuel. Although there may be some renewable fuel used for upstream energy, we assumed that this entire volume is petroleum because the volume of renewable and alternative fuels is fixed by the RFS2 standard.

We assumed that a portion of the gasoline displaced by ethanol would have been produced from domestic refineries causing reduced demand from US refineries, while the rest of the additional ethanol displaces imported gasoline or gasoline blendstocks which does not affect domestic refining sector costs. To estimate the portion of new ethanol which displaces US refinery production we relied on some Markal refinery modeling conducted for us by DOE. The Markal refinery model models all the refinery sectors of the world and thus can do a fair job estimating how renewable fuels would impact imports of finished gasoline and gasoline blendstocks. The Markal refinery model estimated that 2/3rds of a reduction in petroleum gasoline demand would be met by a reduction in imported gasoline or gasoline blendstocks, while the other 1/3rd would be met by reduced refining production by the US refining sector. In the case of biodiesel and renewable diesel, all of it is presumed to offset domestic diesel fuel production. For ethanol, biodiesel and renewable diesel, the amount of petroleum fuel displaced is estimated based on the relative energy contents of the renewable fuels to the fuels which they are displacing. The savings due to lower imported gasoline and diesel fuel is accounted for in the energy security analysis contained in Section 5.2.

For estimating the U.S. refinery industry cost reductions, we multiplied the estimated volume of domestic gasoline and diesel fuel displaced by the projected wholesale price for each of these fuels in 2022, which are $3.42 per gallon for gasoline, and $3.83 per gallon for diesel fuel (see Section 4.4). For the volume of petroleum displaced upstream, we valued it using the wholesale diesel fuel price. Table 4.3-1 shows the net volumetric impact on the petroleum portion of gasoline and diesel fuel demand, as well as the reduced refining industry costs for 2022.

**Table 4.3-1**
**Changes in U.S. Refinery Industry Volumes and Costs for the RFS2 Program in 2022 Relative to the AEO 2007 Reference Case**
**(2007 dollars)**

| | | Low Ethanol Case | | Primary Case (mid-ethanol case) | | High Ethanol Case | |
|---|---|---|---|---|---|---|---|
| | | Bil Gals | Bil $ | Bil Gals | Bil $ | Bil Gals | Bil $ |
| Upstream | Petroleum | 0.34 | 1.3 | 0.34 | 1.3 | 0.33 | 1.3 |
| End Use | Gasoline | -0.9 | -3.1 | -2.0 | -6.8 | -4.4 | -15.0 |
| | Diesel Fuel | -10.1 | -38.7 | -7.5 | -28.7 | -1.3 | -5.0 |
| | Total | -10.7 | -40.5 | -9.2 | -34.2 | -5.4 | -18.7 |

For the primary control case, this analysis estimates that the RFS2 program would reduce the gasoline and diesel fuel production volume of US refineries by 9.2 billion gallons in 2022, which would reduce their production costs by $34 billion dollars. Accounting for all the petroleum displaced (domestic and foreign), the RFS2 program is estimated to reduce gasoline and diesel fuel demand by 13.6 billion gallons.

## 4.4 Overall Costs to Gasoline and Diesel Fuel

The previous sections of this chapter have presented estimates of the cost of producing and distributing ethanol, biodiesel and renewable and cellulosic diesel fuel. In this section, we summarize the overall cost of the RFS2 program by assessing the costs of using more renewable fuels in the transportation fuel supply. The analysis was conducted in two steps. One step involved running a refinery model for estimating the costs of using more ethanol and blending it into gasoline. We used the Haverly Linear Programming (LP) model to conduct the refinery analysis. This model is widely used by the refining industry, consultants, engineering firms and government agencies to analyze refinery economics, refinery operations, fuel quality changes, refinery capital investments, environmental changes and demand changes. This Haverly model uses Jacobs's Refining Process Technology Database to represent refining operations.

While the change in volumetric demand for petroleum-based diesel fuel was modeled with the Haverly refinery model, the modeling of the cost of blending and using cellulosic and renewable diesel fuel and biodiesel on the overall cost of diesel fuel was estimated as a second step post-refinery modelling. Assessing the costs of blending of renewable diesel fuels post-refinery modeling inherently assumes that the renewable diesel fuels will be drop in replacements for petroleum-based diesel fuel. However, if the higher cetane values for cellulosic and renewable diesel fuel and biodiesel can be taken advantage of by refiners in blending up diesel fuel, then our cost estimates are likely to be conservative. We provide a more detailed description about how we estimated the costs of using cellulosic and renewable diesel fuel and biodiesel at the end of subsection 4.4.1.

### 4.4.1 Description of Cases Modeled and Methodology

The fuels cost analysis was set up to analyze the volumes required by the RFS 2 as described in Section 1.2. Because of the uncertainty in how cellulosic biofuel industry will develop over time, we assessed three different renewable fuels scenarios each of which totaled 36 billion gallons based on the energy equivalency of ethanol. The three cases represent a high quantity of cellulosic ethanol and a low amount of cellulosic diesel fuel, a low amount of cellulosic ethanol and a high amount of cellulosic diesel, and a midpoint between these two cases which served as our primary control case. We also considered a small amount of biodiesel and renewable diesel as required under EISA.

The refinery modeling analysis analyzed the extent to which ethanol will be used in conventional gasoline and reformulated gasoline by region and the resulting effects on gasoline composition. The refining industry was modeled based on five aggregate complex refining regions, representing Petroleum Administration for Defense Districts (PADD) 1, 2, 3, 4 & 5 together minus California, and California separately. All of the PADDS were modeled simultaneously together in the LP model which allowed the refinery model to most efficiently rebalance the regional gasoline production volumes in response to the addition of the renewable fuels. We conducted the refinery modeling analysis assuming that crude oil would be priced at about $51 per barrel and product prices were set based on this crude oil price. We adjusted the costs to reflect a crude oil price of $116 per barrel which is the reference crude oil price estimated by the Energy Information Administration (EIA) for its 2009 Annual Energy Outlook (AEO).[1166]

The fuels cost analysis was conducted in three distinct steps which involved a base case, two reference cases and the three control cases.

#### 4.4.1.1 Base Case

The first step involved the establishment of a 2004 base case which calibrated the refinery model against 2004 volumes, gasoline quality, and refinery capital in place. We chose 2004 because the following year, 2005, as well as the beginning of 2006, were affected by hurricanes and would not be representative of a typical year, and 2007 and 2008 were years of extreme crude oil price volatility which skews the price relationships between crude oil and gasoline and diesel fuel. Refinery unit capacities from the Oil and Gas Journal and Energy Information Administration (EIA), as well as refinery feedstock and product volumes from EIA data were entered into the refinery model. The refinery model was then run and the resulting gasoline quality compared and calibrated to actual gasoline quality data information from EPA’s Reformulated Gasoline data base.

#### 4.4.1.2 Reference Cases

The reference cases are benchmark cases that serve as references to the control cases. Thus, the only difference between the control cases and the reference cases is that the control cases model the RFS2 volumes of renewable fuels versus lesser volumes in the reference cases. We established two reference cases. One represented the volumes of renewable fuels assumed for the RFS1 program. The second reference case represented the growth of renewable fuels by

EIA's 2007 Annual Energy Outlook (AEO). The volumes for both these cases are summarized in Section 1.2 above. Because the RFS2 fuel standard becomes fully implemented in 2022, we established our reference cases using the projected volumes of finished products in 2022. These projected volumes were based on the energy demand for gasoline and diesel fuel from the EIA's AEO 2009. The projected volumes were used for establishing total finished product production which then led to refinery production levels for each PADD.

The refinery modeling was conducted using a projection of crude oil and product prices in 2022 that Jacobs made for the proposed rulemaking. The average price of crude oil was projected to be about $51 per barrel, although crude oil prices varied by PADD. Jacobs based the prices for refined products based on the historical price spreads of fuels between the PADDs, using information from EIA's 2004 price information tables, Platts, and AEO 2006. For the reference case as well as for the control cases, we assumed the same crude oil and product prices when conducting the refinery modeling work. The crude oil prices and summertime and wintertime prices for gasoline, diesel fuel and jet fuel used in the refinery modeling are summarized in Table 4.4-1.

**Table 4.4-1. Crude Oil and Finished Product Prices used in Refinery Modeling**

| | | PADD 1 | PADD 2 | PADD 3 | PADD 4/5 CA excl. | California |
|---|---|---|---|---|---|---|
| Crude Oil ($/bbl) | Year-round Average | 53.6 | 53.0 | 50.6 | 51.8 | 50.2 |
| Reformulated Gasoline (c/gal) | Summer | 175.2 | 173.5 | 170.8 | - | 186.7 |
| | Winter | 161.4 | 158.7 | 155.3 | - | 173.7 |
| Conventional Gasoline (c/gal) | Summer | 167.6 | 165.1 | 161.4 | 173.6 | - |
| | Winter | 154.0 | 151.8 | 148.5 | 160.4 | - |
| Diesel Fuel (c/gal) | Summer | 156.6 | 157.6 | 154.6 | 166.6 | 164.6 |
| | Winter | 162.6 | 163.6 | 160.6 | 172.6 | 170.6 |
| Jet Fuel (c/gal) | Summer | 158.6 | 158.6 | 156.6 | 164.6 | 164.6 |
| | Winter | 156.6 | 156.6 | 154.6 | 162.6 | 162.6 |

However, AEO 2009 projected crude oil prices to be $116 bbl in 2022, which is much higher than those that Jacobs had estimated. After completing the refinery modeling, we adjusted the costs of using the renewable fuels post-refinery modeling using a methodology described below in Subsection 4.4.1.6.

We also modeled the implementation of several environmental programs that will have required changes in fuel quality by 2022, including the 30 ppm average gasoline sulfur standard, the 15 ppm cap standards on highway and nonroad diesel fuel and the Mobile Source Air Toxics (MSAT) benzene standard. Although there may still be a small amount high sulfur diesel fuel, we assumed that all distillate fuel would be ultra low sulfur in compliance with the 15 ppm cap standard required by the highway and nonroad diesel fuel sulfur standards. We modeled the implementation of the 2005 Energy bill, which by rescinding the RFG oxygenate standard, resulted in the discontinued use of MTBE, and a large increase in the amount of ethanol blended into reformulated gasoline.[1167] By using the AEO 2009 energy demand we also included the EISA Corporate Average Fuel Economy (CAFE) standards that were mandated in EISA and modeled in AEO 2009.[1168] The assumed EISA vehicle CAFE standard as projected by EIA in AEO phases-in less aggressively than the EPA and NHTSA proposed greenhouse gas and CAFE standards. However, because both programs would be fully phased in by 2022, their net effects in 2022 would not be that different. So basing our refinery modeling analysis on the EISA CAFE standard versus the EPA/NHTSA proposed standard would not make a significant difference in our costs.

### 4.4.1.3 Control Cases

The third step in the refinery modeling analysis was to model the control cases. As stated above, we modeled three different control cases to capture the impacts of a range of different levels of cellulosic ethanol versus cellulosic diesel fuel. All three cases model increased volumes of corn ethanol, biodiesel and renewable diesel fuel. Tables 1.2-1 through 1.2-3 in Section 1.2 of the RIA summarize the volumes modeled for the control cases. For the additional ethanol blended into the gasoline pool, a substantial portion of the additional ethanol was blended as E85. The cost and other implications of the control cases are compared to the reference cases to assess the costs of the program. We ran these multiple cases to understand how costs change based on different levels of cellulosic ethanol versus cellulosic diesel fuel.

The gasoline and diesel fuel product energy output for each control case modeled was maintained the same as that for the reference cases which modeled the energy demand of the AEO 2009. Thus, as the volumes of lower energy dense renewable fuels increased, the total volume of combined renewable and conventional fuels was increased to maintain the same level of energy demand. Maintaining constant energy output assumes that vehicle miles traveled would remain the same between the various cases despite any change in gasoline and diesel fuel prices caused by the use of renewable fuels. In reality the increased use of renewable fuels may result in changes to fuel prices to consumers, either directly as estimated in this section, or indirectly by affecting world oil prices as discussed in Chapter 5, and changes in fuel prices would be expected to affect demand. However, our analysis was conducted in parallel without the ability to input the results of the other analysis. Furthermore, it is difficult to predict the impacts on fuel prices to consumers, especially in light of the federal tax subsidies which we attempted to account for in our analysis, and the many and diverse state tax subsidies which we did not attempt to account for. Maintaining constant fuel product energy output captures the capital cost differences between the cases. Table 4.4-3 below summarizes the volumes of gasoline and diesel fuel used for the two reference cases, the primary control case and the two other control cases. The gasoline volumes include the volumes of renewable fuels, while the diesel fuel volumes do not since diesel fuel costs were estimated post refinery modelling.

**Table 4.4-2.**
**Volumes of Gasoline and Diesel Fuel Used in Refinery Modeling**
**(Billion Gallons/yr)**

| | RFS 1 Reference Case | AEO 2007 Reference Case | Low Ethanol Control Case | Mid-Ethanol Control Case Primary Case | High Ethanol Control Case |
|---|---|---|---|---|---|
| Gasoline Volume (Gasoline and Ethanol) | 136.3 | 138.2 | 139.6 | 141.1 | 144.7 |
| Diesel Fuel Volume (Diesel Only) | 70.7 | 70.6 | 60.7 | 63.3 | 69.4 |

All the other fuel standards and ASTM fuel quality constraints modeled in the reference case described above are assumed to apply to the control case as well. The reference and control cases where modeled assuming that ethanol conventional gasoline blends are entitled to the current 1.0 psi RVP waiver during the summer (i.e., for all 9.0 RVP and many low RVP control programs) so as to correctly assess the use of butanes in summertime conventional gasoline. Reformulated gasoline (RFG), however, must meet the same volatility standard with or without ethanol, so the addition of ethanol into RFG forced the refinery model to remove the last of the butane and some pentanes to rebalance RVP. Wintertime conventional and reformulated gasoline are normally blended up to either the RVP or vapor/liquid ASTM limits so the addition of ethanol into the wintertime gasoline pools resulted in the removal of light hydrocarbon compounds – normally butane. The crude oil and product prices for the control cases were the same as the reference cases. The capital investments made for the reference cases are not assumed to be sunk when the refinery model is assessing the economics for capital investments for the various control cases. Thus, the refinery model is free to optimize the capital investments made for each control case incremental to the base case. The control cases are run with capital costs evaluated at a 15 percent rate of return on investment (ROI) after taxes, but are then adjusted post-modeling to a 7 percent ROI before taxes.

### 4.4.1.4 Ethanol Blending and Prices

A special procedure was set up in the refinery model to capture the costs of blending ethanol. Because ethanol is primarily produced in the Midwest, but distributed to the final terminals where it is blended with the gasoline (or gasoline blendstock for blending with ethanol), hypothetical terminals were set up in each PADD within the refinery model which would receive the shipped ethanol as well as the gasoline blendstock for blending with ethanol (also referred to as conventional blendstock for oxygenate blending (CBOB) for conventional gasoline and reformulated blendstock for oxygenate blending (RBOB) for RFG and for California RFG (CARBOB). The gasoline blendstock either comes from the same PADD where the terminal is located, or transferred from a different PADD. This refinery modeling technique helps to more correctly estimate the distribution costs for both the ethanol and the gasoline. The refinery model assessed ethanol’s use in each PADD based on its price relative to CG and RFG, which is based on its production cost and distribution costs, and its blending economics. For the base case we assumed that ethanol would be splash blended into gasoline. But for both the reference and control cases modeled in the year 2022 we expect that most, if not all, of the ethanol will be octane match-blended for blending up E10.

The price of ethanol used in the reference case and the primary control cases were based on the 2004 yearly average price spread between regular conventional gasoline sold into the spot market in Houston and ethanol sold on the spot market on Chicago Board of Trade (CBOT). This price spread was 12.3 cents per gallon lower than gasoline in the summer, and 7.7 cents per gallon lower than gasoline in the winter. This worked out to an average ethanol price of 146.8 c/gal in the summer, and 139.4 in the summer. To derive ethanol prices for all the PADDs, the Midwest ethanol production price was then adjusted for transportation costs to deliver ethanol from the Midwest to end use terminals (see Section 4.2 for additional details about the distribution costs). This assumes that the Midwest ethanol market will continue to set the price for ethanol – a reasonable assumption considering the significant amount of corn and other biomass available in the Midwest. The sales prices assigned to ethanol are summarized in Table 4.4-4.

**Table 4.4-3. Ethanol Prices used in Refinery Modeling (c/gal)**

| | PADD 1 | PADD 2 | PADD 3 | PADD 4/5 CA excl. | California |
|---|---|---|---|---|---|
| Summer | 166.2 | 158.9 | 164.3 | 170.4 | 170.2 |
| Winter | 158.8 | 151.5 | 156.9 | 163.0 | 162.8 |

After the refinery modeling was completed, the ethanol prices and the costs for each case were adjusted to reflect the ethanol production and distribution costs described above in Sections 4.1 and 4.2. The ethanol production cost is the volume-weighted average for ethanol sourced from corn, cellulose and imports. The ethanol production and distribution cost and cellulosic and renewable diesel and biodiesel costs for 2022 are shown in Table 4.4-4

### Table 4.4-4.
### Average 2022 Production and Distribution Costs for Ethanol, Biodiesel and Cellulosic and Renewable Diesel Fuels

| | Production Cost (c/gal) | Low Ethanol Case | | Primary Case Mid Ethanol Case | | High Ethanol Case | |
|---|---|---|---|---|---|---|---|
| | | Distribution Cost | Total Cost | Distribution Cost | Total Cost | Distribution Cost | Total Cost |
| Corn Ethanol | 150 | 23.2 | 173.2 | 21.6 | 171.6 | 18.8 | 168.8 |
| Cellulosic Ethanol | 127 | 23.2 | 150.2 | 21.6 | 148.6 | 18.8 | 145.8 |
| Imported Ethanol | 150 | 23.2 | 173.2 | 21.6 | 171.6 | 18.8 | 168.8 |
| Biodiesel from virgin oils | 273 | 20.0 | 293 | 20.0 | 293 | 20.0 | 293 |
| Biodiesel from waste oil | 243 | 20.0 | 263 | 20.0 | 263 | 20.0 | 263 |
| Biodiesel from corn oil | 190 | 20.0 | 210 | 20.0 | 210 | 20.0 | 210 |
| Biodiesel from algae oil | 452 | 20.0 | 472 | 20.0 | 472 | 20.0 | 472 |
| Renewable Diesel Fuel from waste oil | 242 | 15.7 | 257.7 | 15.4 | 257.4 | 14 | 256 |
| Cellulosic diesel from BTL | 237 | 15.7 | 252.7 | 15.4 | 252.4 | 14 | 251 |

The ethanol production and distribution costs summarized in Table 4.4-4 are different in value compared to the ethanol prices used in the refinery modeling summarized above in Table 4.4-3. To capture the costs of the RFS2 program renewable fuel volumes, we adjusted the initial costs of the refinery modeling cost analysis using the ethanol production and distribution costs. This cost adjustment was made by multiplying the difference in ethanol cost or price between Tables 4.4-4 and 4.4-3 by the difference in ethanol volume modeled between the control case and the reference case.

We also estimated the costs of the RFS2 program renewable fuel volumes taking into account the consumption subsidies for corn ethanol, cellulosic ethanol, biodiesel and renewable diesel fuel. While these subsidies conceal large portions of the costs of renewable fuels, their economic effects deserve to be understood.

### 4.4.1.5 E85 Blending and Prices

Today E85 is blended at 85 percent by volume in the summer and at 70 percent by volume in the winter. Ethanol must be blended at less than 85 percent in the winter because of ethanol’s low blending Reid Vapor Pressure (RVP). Unlike when ethanol is blended at 10 percent and causes a large vapor pressure increase, when ethanol is blended at 85 percent it blends much closer to its very low neat blending RVP of 2.2. The denaturant provides a small

RVP increase to the neat ethanol, however, the amount of denaturant which may be blended into neat ethanol was recently limited to 2 percent. The lower denaturant volume limits the RVP increase that the denaturant will have on neat ethanol.

When ethanol is blended with gasoline at the terminal to make E85, the available gasoline blendstock must be used. Today this blendstock is either a conventional blendstock for oxygenate blending (CBOB) or reformulated blendstock for oxygenate blending (RBOB) used for blending E10 to the local gasoline specifications. For example, reformulated gasoline (RFG) must comply with the hydrocarbon standard of the RFG program and therefore RFG tends to have an RVP of 6.8, and the RBOB that is blended with ethanol has an RVP of about 5.8. When this 5.8 RVP RBOB is blended with ethanol to make E85, its final RVP is estimated to be 4.72. However, the RVP minimum specified in the E85 ASTM standard shows the summertime lower limit of E85 is 5.5, thus, blending RBOB with 85 percent ethanol would not comply with the ASTM lower RVP standard. Table 4.4-7 summarizes ethanol's blending RVP, gasoline's RVP and the final blend RVP for summertime RFG and CG gasoline, and compares the blends RVP values to that of the E85 ASTM RVP standards.[1169]

**Table 4.4-5. Comparison of E85 RVP levels to the ASTM RVP Standard**

| | Summer E85 | | | Winter E70 | |
|---|---|---|---|---|---|
| Gasoline RVP[a] | CG 10.0 | RFG & low RVP 6.8 | ASTM Std | CG/RFG 14 | ASTM Std |
| Gasoline Blendstock RVP | 9.0 | 5.8 | | 13 | |
| Ethanol Blending RVP | 4.37 | 4.37 | - | 6.1 | |
| Blend RVP | 5.20 | 4.72 | 5.5 minimum | 5.85 | 9.5 minimum |

[a] Summertime CG is allowed a 1 psi waiver for blending with ethanol, however, RFG and some low RVP areas and wintertime CG/RFG do not normally receive 1 psi waivers.

Table 4.4-7 shows that summertime RFG and CG and wintertime gasoline cannot meet the ASTM RVP minimum standards based on blending ethanol with the locally available gasoline blendstock for blending up E10. For this reason, we ran the refinery model assuming that E85 will be blended differently in the future than it is today if it is to be used in large volumes. We assumed in the refinery modeling that all E85 will be blended at 85 percent ethanol year-round by being blended with some butanes or pentanes (whichever is available from the nearest refineries) to bring E85 up to the maximum ASTM RVP standard for E85, in addition to the CBOB or RBOB being supplied to the local area. The maximum ASTM E85 RVP standard is 8.5 in the summertime and 12.0 in the wintertime.

E85 is expected to be priced much lower in the marketplace than E10 and even less relative to gasoline (E0) because of E85's lower energy density. E85 contains about 83,500 BTUs per gallon compared to E10 which contains about 111,300 BTUs per gallon. Thus, when consumers consider refueling their vehicle using E85, they will bypass using it unless it is priced at parity with gasoline on an energy basis. Parity pricing means that E85 would have to be priced about 25 percent lower than E10. Assuming that E85 is priced 25 percent lower than E10 at retail to account for the energy content differences, the pricing disparity between ethanol and gasoline is even greater at the terminal. Table 4.4-6 summarizes the pricing of E85 at retail and at the terminal where ethanol is usually blended with gasoline blendstock to create the E85. Retail markup averages about 10 cents per gallon.[1170] Federal and state taxes average 46 cents per gallon (although this varies significantly by state), and transportation from the terminal to retail averages 3 cents per gallon.[1171] Thus, if E10 gasoline is priced at 163 cents per gallon at the terminal,[SSSSSSSSSS] it would be priced at 222 cents per gallon at retail when the costs for transporting the fuel to the retail market and taxes and retail markup are added on. Based on E85's 25 percent lower energy density, E85 would have to be priced at 167 cents per gallon at retail to reflect its lower energy density. Using the same terminal to retail costs/taxes, E85 would be priced at 108 cents per gallon at the terminal. All this is shown in Table 4.4-6. The bottom row of the table shows what ethanol (E100 plus denaturant) would have to be priced at for terminals to breakeven using ethanol in E85 (this assumes that E85's gasoline blendstock is priced the same as E10 at the terminal). Thus, unlike with E10 where the lower energy content of ethanol is largely transparent to the consumer, based on ethanol's energy content alone, ethanol used in E85 would have to be discounted significantly compared to gasoline for refiners to find it cost-effective to use.

**Table 4.4-6. E85 Pricing at Retail and at Terminals (cents per gallon)**

| | Price at Retail | Retail Markup | Average Federal and State Taxes | Transportation terminal to retail | Terminal Price |
|---|---|---|---|---|---|
| Gasoline E10 | 222 | 10 | 46 | 3 | 163 |
| E85 | 167 | 10 | 46 | 3 | 108 |
| Ethanol Breakeven Price | - | - | - | - | 97 |

In addition to this effect of energy equivalency, Section 1.7 above outlines the difficulty of using all this E85 because of the relatively low number of fuel flexible vehicles (FFVs) that will be available to consume the fuel. The relatively low number of FFVs means that the refueling rate of these vehicles will have to be very high. In the year 2022, we estimate that FFVs will have to refuel 74 percent of the time to use the volume of ethanol required by the RFS2 standard.[TTTTTTTTTT] This means that E85 may have to be priced significantly lower than gasoline for FFV owners to choose to fuel on it instead of gasoline. In addition, it is unlikely that every service station would make the capital investments to make E85 available for sale. In Section 4.2, we estimate that, at most, one out of very four service stations will carry E85. Thus, E85 may have to be priced even lower than its fuel economy-adjusted price to entice FFV owners to refuel at a station carrying E85. To estimate the marginal lower price at which FFV

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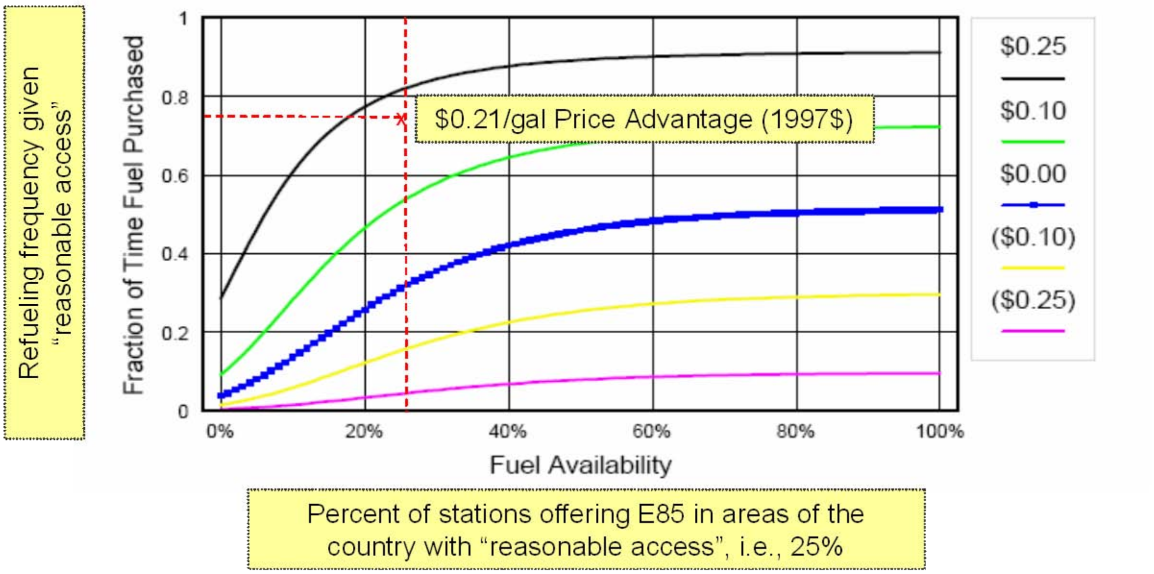
[SSSSSSSSSS] The terminal price of 163 c/gal is the wholesale gasoline priced used in the refinery modeling analysis.

[TTTTTTTTTT] The FFV refueling percentage was estimated at 74% for the proposed rulemaking. Because the refinery modeling analysis was started before the FFV refueling percentage was reassessed for the final rulemaking, we continued to base our analysis on the 74% refueling figure as well as other proposed rulemaking assumptions. Section 1.7.4 contains the updated FFV refueling percentages that we estimated for the final rulemaking.

owners would refuel at this high rate, we referenced an analysis based on a willingness to pay survey conducted by David Greene of the Oak Ridge National Laboratory.[1172] The summary of this analysis is depicted in the Figure 4.4-1.

**Figure 4.4-1**

*Alternative Fuel Market Share as a Function of Fuel Availability and Price Advantage (David L. Greene, 1997, Figure 6)*


Refueling frequency given "reasonable access"

$0.21/gal Price Advantage (1997$)

Percent of stations offering E85 in areas of the country with "reasonable access", i.e., 25%

Based on our estimates that E85 would have to be purchased 74 percent of the time and that one out of every four service stations would carry E85, then Figure 4.4-1 estimates that E85 would have to be priced 21 cents per gallon lower than gasoline to match this availability and refueling scenario in addition to the adjustment for energy content. This cost estimate is based in 1997 dollars. Adjusting this cost estimate to 2006 dollars increases this estimate to 26 cents per gallon in addition to the adjustment for energy content.

There is one more factor which we believe could affect the price of E85. FFV owners who refuel on E85 will drive fewer miles before having to refuel compared to operating their vehicle on gasoline. The FFV drivers will therefore spend more time refueling their vehicle. As described above, FFV owners will drive 25 percent fewer miles per gallon and thus, will have to spend 25 percent more time refueling. We estimate that each refueling event requires 6 minutes of time, and that a person's time is worth an average of 30 dollars per hour.[1173,1174,1175,1176] Finally we assumed that a typical refueling volume for a refueling event is 15 gallons. Using these assumptions, the increased refueling frequency is costing the average FFV owner 5 cents per gallon more to use E85. To account for this additional cost, E85 would have to be priced 5 cents per gallon lower to make refueling FFVs a breakeven proposition. For our refinery modeling work, we reduced the refiner purchase price of E85 used in our refinery modeling analysis by this additional 5 cents per gallon.

Table 4.4-7 summarizes the E85 refinery purchase prices at terminals by PADD used in our refinery modeling work. These prices represent the total of the energy content, the price adjustment for reduced fuel availability and the cost for increased refueling events. The E85 prices should be compared to regular grade gasoline because the FFVs generally only require regular grade gasoline when operated on gasoline.

**Table 4.4-7. Wholesale E85 Prices used within the Refinery Model**

| | | E85 used in Conventional Gasoline Areas (c/gal) | E85 used in Reformulated Gasoline Areas (c/gal) |
|---|---|---|---|
| PADD 1 | Summer | 76 | 81 |
| | Winter | 67 | 72 |
| PADD 2 | Summer | 75 | 80 |
| | Winter | 66 | 71 |
| PADD 3 | Summer | 74 | 79 |
| | Winter | 65 | 70 |
| PADDs 4/5 | Summer | 84 | 80 |
| | Winter | 75 | 81 |
| CA | Summer | - | 86 |
| | Winter | - | 77 |

While we used these E85 prices within the refinery model, they don't necessarily represent the societal costs for using E85. The pricing to reflect reduced fuel availability, in particular, contains a significant amount of transfer payments from the refining industry to consumers and other entities, and these transfer payments do not represent the true cost for using E85.[UUUUUUUUUU]

For estimating the program costs for using E85 shown in Tables 4.4-12 and 4.4-13 (and subsequent tables for related cases), we adjusted E85 price back up to 5 cents per gallon less than the gasoline price for each case (the additional time spent refueling is a true cost). We then used the relative energy density of the E85 to that of gasoline as reported by the refinery model (see energy content values in Table 4.4-19 and other similar tables) to account for the energy density costs for using E85. We preferred the energy content price cost made by the refinery model to our preliminary E85 energy content price adjustments because the refinery model accounts for other changes in gasoline energy content made when accommodating the blending of ethanol . We are not assuming that the price adjustment that we made account for lower E85 availability accounts for any additional social cost. If the FFV driver would have to drive out of his way from time-to-time to find the E85, then there would be some extra cost associated with the lower availability. But most of the time FFV drivers would likely learn where to find E85 along the routes that they normally frequent, thus, no additional effort and cost would be incurred for refueling on E85. Thus, we assume that the lower E85 price to account for reduced E85 availability is purely a transfer payment from the refiner to the FFV owner. Despite assessing the costs on a different basis, estimating E85 prices for the refinery modeling is important so that the refinery model can correctly choose which gasoline type and which part of the country to

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[UUUUUUUUUU] The possibility for this potentially large transfer payment associated with using ethanol in E85 would encourage obligated parties to pursue the development of nonethanol renewable fuels.

blend the ethanol in the refinery model.

The assumption used here and throughout this rulemaking is that ethanol's fuel economy is directly proportional to its energy density and its concentration in the fuel. Since the volumetric energy content of ethanol is approximately 33 percent less than conventional gasoline, we assumed this loss in fuel economy proportional to its concentration in the fuel. Some studies have suggested, however, that ethanol's decrease in fuel economy may be less than its relative decrease in volumetric energy content of the fuel. In other words, there is less of a fuel consumption decrease than what the lower energy density of ethanol would suggest. However, the results may more be a function of how the testing was conducted than the true effect of ethanol on fuel economy. We therefore intend to investigate this issue more as more data becomes available.

As discussed above, we needed to adjust the estimated program costs from costs based on $51/barrel crude oil, the crude oil price at which the refinery model was run, to $116/bbl which is the crude oil costs that served as the basis for our cost analysis. To make these adjustments we estimated the wholesale gasoline and diesel fuel prices (which are the surrogate for the gasoline and diesel fuel production costs) at the adjusted crude oil price and compared these adjusted wholesale gasoline and diesel fuel adjusted prices to the baseline wholesale gasoline and diesel fuel prices. The baseline wholesale gasoline and diesel fuel prices, based on an average $51/bbl crude oil price, are summarized in Table 4.4-1. To adjust these wholesale prices, we estimated how the price of crude oil will affect them. We conducted a regression between the annual average spot price of price of Western Texas Intermediate crude oil and the annual average retail gasoline and diesel fuel prices for the years 2002 through 2008.[1177,1178] This regression is reflected in Table 4.4-8 as Gasoline Retail Price = Crude Oil Price multiplied times 2.65 plus 79.0, or Gasoline Retail Price = Crude Oil Price x "X" + "Y." The slope "X" and intercept "Y" for this equation are summarized in Table 4.4-8. The X and Y factors for diesel fuel are also summarized in Table 4.4-8 as well. However, we needed to estimate the wholesale prices instead of the retail prices, so we adjusted the equations to estimate the wholesale price using the Jacob's wholesale prices as the calibrating values. The regression, including the adjustment values to derive the wholesale prices equations are summarized in Table 4.4-8.

**Table 4.4-8.**
**Equations Used for Estimating Wholesale Average Gasoline and Diesel Fuel Prices***

| | Equation for Retail Prices | | Equation for Wholesale Prices | |
|---|---|---|---|---|
| | X | Y | X | Adjusted Y |
| Gasoline | 2.65 | 79.0 | 2.65 | +27.0 |
| Diesel Fuel | 3.38 | 44.8 | 3.38 | -11.7 |

* The equation is used by multiplying the crude oil price ($/bbl) times the X and then adding Y to that product resulting in a gasoline or diesel fuel cost expressed in cents per gallon.

The equations were used to estimate the average wholesale gasoline and diesel fuel prices. These average wholesale gasoline and diesel fuel prices are summarized in Table 4.4-9.

**Table 4.4-9**
**Average Gasoline and Diesel Fuel Wholesale Prices by Crude Oil Price**

| Crude Oil Price | Gasoline | Diesel Fuel |
|---|---|---|
| $/bbl | c/gal | c/gal |
| 51 | 163 | 160 |
| 116 | 342 | 383 |

Table 4.4-9 shows the nationwide average costs, but our cost analysis was conducted on a PADD basis, thus, it was necessary to estimate revised gasoline and diesel fuel wholesale prices in each PADD. This was accomplished by generating a ratio of the average wholesale gasoline and diesel fuel prices at the higher crude oil price relative to the average gasoline and diesel fuel wholesale prices at the lower crude oil price, and applying this ratio to the gasoline price in each PADD. It is important to point out one aspect of the gasoline and diesel fuel pricing changes captured by our crude oil/gasoline and diesel fuel price relationship price model. Prior to 2005, diesel fuel was priced about the same as gasoline (+/- 5 cents per gallon on a yearly average). In 2005 and 2006, when crude oil was priced higher, diesel fuel was priced 13 cents per gallon higher than gasoline. In 2007 gasoline and diesel fuel were priced about the same, but then in 2008, diesel fuel was priced much higher than gasoline. Thus, the equation picks up this relatively higher diesel fuel price at the higher crude oil prices in 2005, 2006 and 2008 and projects a greater relative higher price for diesel fuel at our high crude oil price of $116/bbl. A higher relative diesel fuel price at higher crude oil prices in the future may be appropriate for a couple reasons. The first reason is that from January to mid-October 2008, when crude oil prices were very high, diesel fuel averaged 51 cents per gallon higher than gasoline. While we cannot say for certain that this association would always hold true at higher crude oil prices, we do have a possible explanation for a possible relationship here. Higher crude oil prices are likely to affect gasoline demand more than diesel fuel as more of the trips made by gasoline powered light-duty vehicles are discretionary. For example, people may readily change their vacations plans at higher crude oil prices, while diesel fuel used to power trucks that bring food to markets would be expected to continue. Thus, as crude oil prices increase, gasoline consumption is likely more elastic resulting in greater reductions in gasoline demand compared to diesel fuel. We therefore believe that higher crude oil prices will tend towards relatively higher diesel fuel prices compared to gasoline.

For other reasons, diesel fuel prices may trend higher in the future relative to gasoline prices. Because EISA required that corporate average fuel economy (CAFE) standards be increased for light duty motor vehicles, over time light duty vehicles, which are almost exclusively gasoline powered, will become more fuel efficient. This will cause gasoline demand to decrease, while diesel demand is projected to continue to increase with GDP to transport goods and services. A second reason why refinery gasoline production will decrease is that most of the renewable fuel volume being produced to comply with the RFS will displace gasoline. This will contribute to the over supply of gasoline and the relative undersupply of diesel fuel, thus causing gasoline prices to be soft relative to diesel fuel prices.

Another adjustment we made to the costs directly estimated by the LP refinery cost model was to add additional cost for distributing gasoline from the refinery to the terminal. The refinery cost model assigned a low distribution costs to gasoline for moving the gasoline from the refinery to the terminal. We estimate that this distribution cost should be about 4 cents per gallon, but the refinery model only assigned 2.5 cents per gallon for this. Thus, we credited ethanol 1.5 cents per gallon for each gasoline-equivalent gallon of ethanol blended into each PADD's gasoline, since this roughly corresponded to the volume of gasoline displaced by the ethanol.

The diesel fuel costs are estimated based on two calculations conducted post-refinery modeling. The first calculation estimates costs based on the difference in the renewable fuels production costs compared to the production costs for petroleum-based diesel fuel multiplied times the increased volume of renewable fuels in the control case compared to the reference case. For example, producing and distributing cellulosic diesel fuel for the primary control case is estimated to cost 252 cents per gallon (see Table 4.4-4). The cost of producing diesel fuel is estimated to be 383 cents per gallon when crude oil is priced at $116 per barrel (see Table 4.4-9), which is 131 cents per gallon higher than the cellulosic diesel fuel costs. From the volume tables in Section 1.2, the incremental volume of cellulosic diesel fuel is 6.52 billion gallons for the primary reference relative to the AEO 2007 reference case. Therefore, the net production cost for cellulosic diesel fuel is -131 cents per gallon times 6.52 billion gallons for a cost of -8540 million dollars in 2022.

The second calculation for estimating the cellulosic diesel fuel costs is an estimate of the fuel economy cost. This is calculated by multiplying the percent loss in fuel economy for cellulosic diesel fuel compared to petroleum-based diesel fuel times the production cost for petroleum-based diesel fuel. Continuing with the cellulosic diesel fuel example, we assume that cellulosic diesel fuel is from the biomass-to-liquids (BTL) process and contains 123,000 BTUs per gallon versus petroleum diesel fuel which is estimated to contain 130,000 BTUs per gallon. Thus, cellulosic diesel fuel contains about 95% of the energy content of petroleum-based diesel fuel. The 5% shortfall in energy content is multiplied times the production cost of petroleum-based diesel fuel, which is 383 cents per gallon, and multiplied times 6.52 billion gallons - the volume of cellulosic diesel fuel. This results in a cost of 1250 million dollars in 2022.

The total cost for cellulosic diesel fuel is the sum of the production cost and the fuel economy cost which is -7290 million dollars in 2022. The total annual cost is converted to a per-gallon cost by dividing the total annual cost by the total volume of petroleum-based and renewable diesel fuel.

#### 4.4.1.6 Other Adjustments to the Costs

The assumed volumes of E85 in our control cases will require increased numbers of flexible fuel vehicles (FFVs) be available to use the fuel. In Section 1.7 above, we estimate the number of FFVs that would be produced to enable the consumption of the volume of E85 that we project would have to be consumed for each control case. As the number of FFVs increases it results in higher costs due to the production of FFVs. In the following tables, we resummarize the number of FFVs that we projected would be available for the AEO 2007 reference case and each control case that we described above in Section 1.7. However, to estimate the cost impacts, we attribute a cost for every FFV produced. For the low ethanol case, we assume that each FFV would cost $100 per vehicle, which is an estimate for producing an FFV today. For the higher ethanol cases, as FFV production volumes increase, because of economies of scale, we expect that the per-vehicle costs would decrease. Furthermore, overhead costs associated with producing FFVs would be amortized over a larger number of vehicles further lowering the per-vehicle costs. For the primary case we project that FFV costs would decrease to $75 per vehicle. For the high ethanol case we assume that FFV costs would decrease to $50 per vehicle. This range in costs is consistent with estimates in literature.[1179] Tables 4.4-10 and 4.4-11 provide estimates of the FFV costs above the business-as-usual FFV costs in the AEO 2007 and RFS 1 reference cases.

**Table 4.4-10**
**Numbers of FFVs and Total FFV Costs for the Control Cases Relative to the AEO 2007 Reference Case**

| | AEO 2007 Reference Case | Low Ethanol Control Case | | Primary Control Case (mid ethanol case) | | High Ethanol Control Case | |
|---|---|---|---|---|---|---|---|
| Year | Number of FFVs (millions) | Number of FFVs (millions) | Incremental FFV Cost (millon dollars) ($100/FFV) | Number of FFVs (millions) | Incremental FFV Cost (millon dollars) ($75/FFV) | Number of FFVs (millions) | Incremental FFV Cost (millon dollars) ($50/FFV) |
| 2010 | 1.67 | 1.25 | -$41.7 | 1.85 | $13.4 | 3.62 | $97.4 |
| 2011 | 1.75 | 1.60 | -$14.8 | 2.66 | $68.6 | 5.44 | $184.6 |
| 2012 | 1.77 | 1.90 | $13.6 | 3.52 | $131.6 | 7.39 | $281.2 |
| 2013 | 1.80 | 2.25 | $45.6 | 3.74 | $145.9 | 9.42 | $381.1 |
| 2014 | 1.83 | 2.52 | $69.7 | 3.88 | $154.1 | 11.40 | $478.8 |
| 2015 | 1.82 | 2.69 | $87.6 | 3.96 | $160.5 | 13.29 | $573.4 |
| 2016 | 1.82 | 2.76 | $94.4 | 3.97 | $161.3 | 13.32 | $575.3 |
| 2017 | 1.83 | 2.80 | $97.8 | 4.00 | $163.3 | 13.44 | $580.8 |
| 2018 | 1.83 | 2.93 | $109.4 | 4.04 | $165.6 | 13.57 | $586.9 |
| 2019 | 1.86 | 2.83 | $97.0 | 4.08 | $167.2 | 13.71 | $592.8 |
| 2020 | 1.90 | 2.77 | $87.1 | 4.12 | $166.3 | 13.82 | $596.2 |
| 2021 | 1.91 | 2.67 | $75.6 | 4.10 | $163.9 | 13.76 | $592.4 |
| 2022 | 1.91 | 2.61 | $69.4 | 4.10 | $163.7 | 13.75 | $591.9 |
| Totals | 23.7 | 31.6 | $791 | 48.0 | $1,826 | 145.9 | $6,113 |

Table 4.4-10 summarizes our estimated costs for the increased numbers of FFVs that would be produced to use the projected increased volume of E85. For the primary control case we estimate that increased FFV production would cost $1.8 billion. For the low and high ethanol control cases we estimate that increased FFV production would cost $0.8 and $6.1 billion, respectively.

### Table 4.4-11
### Numbers of FFVs and Total FFV Costs for the Control Cases Relative to the RFS 1 Reference Case

| Year | RFS 1 Reference Case | Low Ethanol Control Case | | Primary Control Case (mid ethanol case) | | High Ethanol Control Case | |
|---|---|---|---|---|---|---|---|
| | Number of FFVs (millions) | Number of FFVs (millions) | Incremental FFV Cost (millon dollars) ($100/FFV) | Number of FFVs (millions) | Incremental FFV Cost (millon dollars) ($75/FFV) | Number of FFVs (millions) | Incremental FFV Cost (millon dollars) ($50/FFV) |
| 2010 | 0.98 | 1.25 | $27.0 | 1.85 | $64.9 | 3.62 | $131.7 |
| 2011 | 1.08 | 1.60 | $51.5 | 2.66 | $118.3 | 5.44 | $217.8 |
| 2012 | 1.16 | 1.90 | $74.1 | 3.52 | $177.1 | 7.39 | $311.5 |
| 2013 | 1.23 | 2.25 | $101.7 | 3.74 | $188.0 | 9.42 | $409.2 |
| 2014 | 1.28 | 2.52 | $124.2 | 3.88 | $195.1 | 11.40 | $506.1 |
| 2015 | 1.31 | 2.69 | $138.7 | 3.96 | $198.9 | 13.29 | $599.0 |
| 2016 | 1.31 | 2.76 | $145.2 | 3.97 | $199.4 | 13.32 | $600.7 |
| 2017 | 1.32 | 2.80 | $148.3 | 4.00 | $201.2 | 13.44 | $606.0 |
| 2018 | 1.33 | 2.93 | $159.5 | 4.04 | $203.2 | 13.57 | $612.0 |
| 2019 | 1.35 | 2.83 | $147.8 | 4.08 | $205.2 | 13.71 | $618.2 |
| 2020 | 1.36 | 2.77 | $141.2 | 4.12 | $206.9 | 13.82 | $623.2 |
| 2021 | 1.35 | 2.67 | $131.7 | 4.10 | $206.0 | 13.76 | $620.5 |
| 2022 | 1.35 | 2.61 | $125.6 | 4.10 | $205.8 | 13.75 | $620.0 |
| Totals | 16.4 | 31.6 | $1,516 | 48.0 | $2,370 | 145.9 | $6,476 |

Table 4.4-11 summarizes our estimated costs for the increased numbers of FFVs that would be produced to use the projected increased volume of E85. For the primary control case we estimate that increased FFV production would cost $2.4 billion. For the low and high ethanol control cases, we estimate that increased FFV production would cost $1.5 and $6.5 billion, respectively.

### 4.4.2 Refinery Modeling Results

In this subsection, we summarize the results of the three control cases that we modeled and compare them to the two different reference cases.

Table 4.4-12 summarizes the costs for the primary control case relative to the AEO 2007 reference case excluding federal ethanol, biodiesel and renewable diesel tax subsidies. By excluding the federal ethanol, biodiesel and renewable diesel fuel consumption subsidies, we avoid the transfer payments caused by these subsidies that would hide a portion of the program's costs. The costs are reported by different cost components and adjustments described above, as well as aggregated to show the total annual and per-gallon costs. The costs are reported separately for gasoline and diesel fuel. The estimate of gasoline costs are based on the refinery model and reflect the changes in gasoline that are estimated to occur by the refinery model accommodating the expanded use of ethanol. The refinery model variable operating costs include the labor, utility and other operating costs and are a direct output from the refinery model. These costs reflect ethanol's and E85's prices used in the refinery model and reflect crude oil priced at about $51 per barrel. The reduced refinery capital costs are shown in the table amortized annually and over the gasoline pool (the nonamortized refinery and biofuel capital costs are summarized in Table 4.4-18). The fixed costs shown in the table include the maintenance and insurance costs and are calculated to be 3 percent of the reduced capital costs. Next in the table we show the adjustment to remove the costs associated with low E85 prices, except for the 5 cent per gallon refueling cost, and then we show the costs for using lower energy density E10 gasoline and E85. The energy density costs changes rely on the fractional change in energy density shown in Table 4.4-19, multiplied by the wholesale price of gasoline. The cost adjustment is shown for basing the gasoline costs on $116 per barrel crude oil price versus the $51 per barrel price that was the basis for the refinery model runs. At $116 per barrel crude oil costs, ethanol's production and distribution costs are lower than the wholesale cost of gasoline which results in the cost savings. Finally for the gasoline costs, the table summarizes our estimated costs for producing an appropriate number of fuel flexible vehicles (FFVs) for using E85. With respect to the cellulosic and renewable diesel fuel and biodiesel costs, the production costs and for the fuel economy effects are both presented in Table 4.4-12.

### Table 4.4-12.
### Primary Control Case Costs without Tax Subsidies Relative to the AEO 2007 Reference Case

(2007 dollars, 7% ROI before taxes)

| | Gasoline | Diesel Fuel |
|---|---|---|
| Refinery Model Variable Operating Cost $MM/yr | 10,998 | - |
| Amortized Refinery Capital Costs $MM/yr | -997 | - |
| Fixed Operating Costs $MM/yr | -275 | - |
| Added Gasoline Transportation Cost $MM/yr | -88 | - |
| Removal of E85 Pricing Effect $MM/yr | -8,338 | - |
| Crude Oil Cost $51 to $116/bbl $MM/yr | -15,302 | - |
| Lower Energy Density $MM/yr | 8,745 | 1,722 |
| Adjustment from Ethanol Price to Cost $MM/yr | 83 | - |
| FFV Costs $MM/yr | 1,826 | |
| Renewable Diesel Cost vs Petroleum Diesel $MM/yr | - | -10,268 |
| Total Costs $MM/yr | -3,349 | -8,546 |
| Refinery Model Variable Operating Cost c/gal | 7.79 | - |
| Amortized Refinery Capital Costs c/gal | -0.71 | - |
| Fixed Operating Costs c/gal | -0.19 | - |
| Added Gasoline Transportation Cost c/gal | -0.06 | - |
| Removal of E85 Pricing Effect c/gal | -5.91 | - |
| Crude Oil Cost $51 to $116/bbl c/gal | -10.84 | - |
| Lower Energy Density c/gal | 6.20 | 2.42 |
| Adjustment from Ethanol Price to Cost c/gal | 0.06 | - |
| FFV Costs c/gal | 1.29 | |
| Renewable Diesel Cost vs Petroleum Diesel c/gal | - | -14.41 |
| Total Costs c/gal | -2.37 | -11.99 |

Our analysis shows that when considering all the costs associated with the expanded use of ethanol for the primary control case relative to the AEO 2007 reference case that the cost of gasoline will decrease by $3.3 billion in the year 2022. Expressed as per-gallon costs, these fuel changes will save the U.S. 2.4 cents per gallon of gasoline. The addition of biodiesel, renewable and cellulosic diesel fuel is estimated to reduce the cost of diesel fuel by $8.5 billion in the year 2022, or save 12.0 cents per gallon.

Table 4.4-13 expresses the total and per-gallon gasoline costs for the primary control case with the federal ethanol, biodiesel and renewable diesel subsidies included. The federal tax subsidy is 45 cents per gallon for each gallon of ethanol blended into gasoline and 101 cents per gallon for each gallon of cellulosic biofuel. Imported ethanol is also assumed to receive the 45 cents per gallon ethanol subsidy, although we assume that a greater volume of imported ethanol would be used than that which can flow through the Caribbean Basin, tariff free. Thus the 51 cents per gallon tariff would apply to that incremental volume of imported ethanol above the allowable Caribbean Basin initiative volume. We estimate that imported ethanol would earn 23 cents per gallon net subsidy. The biodiesel subsidy is 100 cents per gallon, and the renewable diesel fuel subsidy is 50 cents per gallon. The cost adjustment is estimated by multiplying the subsidy times the volume of new ethanol, biodiesel and renewable diesel estimated to be used.

**Table 4.4-13.**
**Primary Control Case Costs Reflecting Tax Subsidies**
**Relative to the AEO 2007 Reference Case**
(2007 dollars, 7% ROI before taxes)

| | Gasoline | Diesel Fuel |
|---|---|---|
| Total Costs $MM/yr | -3,349 | -8,546 |
| Federal Subsidies $MM/yr | -6,313 | -7,944 |
| Revised Total Cost $MM/yr | -9663 | -16,490 |
| Total Costs c/gal | -2.37 | -11.99 |
| Federal Subsidies c/gal | -4.47 | -11.15 |
| Total Costs c/gal | -6.85 | -23.14 |

The cost including subsidies would represent gasoline and diesel fuel’s apparent cost as reflected to the fuel industry as a whole because the federal tax subsidies tends to transfer a portion of the actual costs to consumers through non-fuel taxes. Our analysis estimates that relative to the AEO 2007 reference case, the primary control case would cause a 6.9 cent per gallon decrease in the apparent cost of producing gasoline, and a 23.1 cent decrease in the apparent cost of producing diesel fuel. These costs would also represent the apparent cost to consumers “at the pump” if the full tax credit were passed along to the consumers. However, it is possible that only a portion of the tax subsidy will be passed along to the consumer (historically, this has been the case). Thus, the price impact at the pump may be somewhere between the values in Tables 4.4-12 and 4.4-13. However, consumers would also pay the full tax subsidy through higher taxes in addition to the values in Tables 4.4-13.

Table 4.4-14 summarizes the volumetric inputs to refineries in each PADD for the primary control case and provides the incremental difference relative to the AEO 2007 reference case. Because of the increased use of biofuels, petroleum inputs would be expected to decrease, and this is confirmed.

# Table 4.4-14.
## Summary of the Total and Incremental Volumetric Refinery Inputs by PADD for the Primary Control Case Relative to the AEO 2007 Reference Case (barrels/day)

| | PADD 1 | | PADD 2 | | PADD 3 | | PADD 4/5 ex CA | | CA | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case |
| PADD Crude | 1,246,981 | -281,399 | 3,117,973 | -340,516 | 7,056,501 | -194,917 | 1,460,255 | -73,349 | 1,865,224 | -24,171 |
| GTL Naphtha | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| GTL Diesel | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| VGO HS | 0 | 0 | 0 | 0 | 0 | -43,785 | 0 | 0 | 0 | 0 |
| VGO LS | 0 | 0 | 38,063 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| HS AR (A960) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LS AR (Alg) | 290,427 | 60,773 | 0 | 0 | 732,497 | 26,283 | 0 | 0 | 0 | 0 |
| Normal Butane | 26,527 | 4,042 | 65,106 | 13,451 | 111,678 | 25,512 | 40,206 | 490 | 39,573 | 0 |
| Isobutane | 9,412 | 8,868 | 17,236 | -6,556 | 25 | 25 | 19,001 | 12,735 | 0 | 0 |
| Other | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| MTBE | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Ethanol - E10 | 300,677 | 27,590 | 188,968 | -8,932 | 155,813 | -19,904 | 69,817 | -573 | 145,656 | 2,998 |
| Ethanol - E20 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Ethanol - E85 | 243,490 | 243,490 | 111,243 | 111,243 | 212,446 | 212,446 | 17,420 | 17,420 | 0 | 0 |
| Reformer Feed | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Methanol | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Natural Gas (FOE) | 68,419 | -12,688 | 135,263 | -9,379 | 490,908 | -13,379 | 87,228 | -6,669 | 154,101 | -1,567 |
| Hydrogen (MSCF) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Pentanes Plus | 0 | 0 | 32,124 | 0 | 52,055 | 0 | 18,580 | 0 | 0 | 0 |
| Import CBOB 10% | 148,371 | 142,085 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Import CBOB 20% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Import RBOB 10% | 65,943 | -79,650 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Import RBOB 20% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Import Alkylate | 19,134 | 16,901 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Import Raffinate | 38,375 | -15,151 | 0 | 0 | 0 | 0 | 0 | 0 | 45,808 | 0 |
| Import Reformate | 7,080 | -1,749 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Import FCC Naphtha | 0 | 0 | 0 | 0 | 17,503 | 17,503 | 0 | 0 | 0 | 0 |
| Import Lt Naphtha | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 584 | 0 |
| Import Hvy Naph | 0 | 0 | 0 | 0 | 41,644 | 0 | 0 | 0 | 0 | 0 |
| Transfer Lt Naphtha | 23,342 | 19,010 | 0 | 0 | 0 | 0 | 0 | 0 | 23,053 | 4,669 |
| Transfer Reformate | 17,226 | 569 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfer Alkylate | 59,431 | -569 | 9,795 | 9,795 | 0 | 0 | 0 | 0 | 60,000 | 0 |
| Transfer FCC Naphtha | 0 | 0 | 20,822 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfer Raffinate | 0 | 0 | 784 | -10,853 | 0 | 0 | 0 | 0 | 60,000 | 12,556 |
| Transfer RBOB 10% | 242,605 | 0 | 37,596 | 37,596 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfer RBOB 20% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfer CBOB 10% | 1,355,660 | 219,387 | 81,092 | 27,037 | 0 | 0 | 9,099 | 2,747 | 0 | 0 |
| Transfer CBOB 20% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Isooctane | 3,278 | 3,178 | 100 | 0 | 100 | 0 | 100 | 0 | 13,287 | -1,975 |
| Isooctene | 17,071 | 16,971 | 100 | 0 | 100 | 0 | 100 | 0 | 2,461 | 1,861 |

Table 4.4-14 shows that inputs of crude oil decreases substantially in most of the PADDs. In all the PADDs the input of crude oil to refineries decreases, which is expected since renewable fuels will supplant the need for petroleum feedstocks. Imports of gasoline blendstocks into PADD 1 also decreases. Butane inputs increase due to its blending into E85.

Table 4.4-15 below summarizes the refinery output volumes and changes in refinery output volumes relative to the reference case by PADD.

# Table 4.4-15.
# Summary of Total and Incremental Refinery Outputs by PADD for the Primary Control Case Relative to the AEO 2007 Reference Case
# (barrels/day)

| | PADD 1 | | PADD 2 | | PADD 3 | | PADD 4/5 ex CA | | CA | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case |
| Propane | 30,305 | -1,816 | 50,863 | -6,424 | 100,460 | -17,092 | 21,022 | -1,481 | 52,834 | 1,242 |
| Propylene | 18,685 | 0 | 42,525 | 0 | 245,407 | 0 | 2,041 | 0 | 11,774 | 0 |
| Normal Butane | 0 | -4,967 | 1,698 | 733 | 23,031 | -10,632 | 0 | 0 | 0 | 0 |
| Isobutane | 0 | 0 | 0 | 0 | 0 | -411 | 0 | 0 | 39,318 | -2,172 |
| PC Naphtha | 15,830 | 0 | 40,290 | 0 | 432,937 | 0 | 0 | 0 | 0 | 0 |
| PC Gasoil | 0 | 0 | 502,059 | -58,642 | 157,500 | 0 | 0 | 0 | 0 | 0 |
| CG Reg | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CG Prem | 0 | 0 | 0 | 0 | 0 | -182,001 | 0 | 0 | 0 | 0 |
| CG E10 Reg | 1,654,618 | 397,669 | 1,277,077 | -100,639 | 850,572 | -224,891 | 577,355 | -8,008 | 96,902 | 1,992 |
| CG E10 Prem | 214,377 | 144,044 | 267,934 | 5,512 | 209,149 | 4,299 | 113,837 | 2,340 | 18,457 | 379 |
| RFG E10 Reg | 885,097 | -271,021 | 273,652 | 5,624 | 405,579 | 19,731 | 0 | 0 | 1,114,370 | 22,903 |
| RFG E10 Prem | 222,613 | 2,400 | 52,124 | 1,071 | 77,253 | 3,758 | 0 | 0 | 212,261 | 4,363 |
| CG E20 Reg | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| RFG E20 Reg | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| E85 to CG | 0 | 0 | 129,577 | 129,577 | 247,459 | 247,459 | 20,291 | 20,291 | 0 | 0 |
| E85 to RFG | 283,619 | 283,619 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfer RBOB 10% | 0 | 0 | 0 | 0 | 280,201 | 37,596 | 0 | 0 | 0 | 0 |
| Transfer RBOB 20% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfer CBOB 10% | 0 | 0 | 0 | 0 | 1,445,851 | 249,171 | 0 | 0 | 0 | 0 |
| Transfer CBOB 20% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Jet/Kero A (450ppm) | 70,000 | 0 | 143,275 | 3,194 | 936,227 | 0 | 274,537 | 0 | 229,653 | 0 |
| X-Fer Diesel Rundown | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| HSD Gr 76 (0.2%) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LSD Gr 74 (.05%) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| ULSD (15 ppm) | 505,645 | -128,972 | 562,879 | -109,292 | 2,011,680 | -124,623 | 470,858 | -62,441 | 0 | 0 |
| CARB Diesel | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 326,650 | -37,699 |
| X-Fer C5's to Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1% Residual Fuel | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residual Fuel | 50,000 | -41,643 | 57,026 | -7,562 | 262,834 | 0 | 126,642 | 4,352 | 49,880 | 0 |
| Slurry | 31,083 | 3,675 | 76,076 | -10,192 | 108,692 | -5,256 | 18,513 | 5,031 | 28,829 | -178 |
| Asphalt & Wax | 91,682 | 0 | 198,329 | -9,357 | 157,500 | 0 | 5,250 | 0 | 41,774 | 0 |
| Gasoil | 0 | 0 | 4,895 | 0 | 0 | 0 | 0 | 0 | 9,814 | 0 |
| Lubes | 18,706 | 0 | 17,313 | 0 | 157,500 | 0 | 0 | 0 | 20,149 | 0 |
| Benzene | 11,003 | 0 | 11,003 | 0 | 51,347 | 0 | 0 | 0 | 0 | 0 |
| Toluene | 0 | 0 | 0 | 0 | 34,910 | 0 | 0 | 0 | 0 | 0 |
| Xylenes | 0 | 0 | 0 | 0 | 7,777 | 0 | 0 | 0 | 0 | 0 |
| Cumene | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Other | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Cyclohexane | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfer Raffinate | 0 | 0 | 0 | 0 | 60,784 | 1,703 | 0 | 0 | 0 | 0 |
| Transfer Alkylate | 0 | 0 | 0 | 0 | 129,226 | 9,226 | 0 | 0 | 0 | 0 |
| Transfer Reformate | 0 | 0 | 0 | 0 | 17,226 | 569 | 0 | 0 | 0 | 0 |
| Transfer FCC naphtha | 0 | 0 | 0 | 0 | 20,822 | 0 | 0 | 0 | 0 | 0 |
| Transfer Lt Naphtha | 0 | 0 | 0 | 0 | 23,342 | 19,010 | 0 | 0 | 23,053 | 4,669 |
| Transfer Blendstock | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sulfur (STons) | 1,008 | -146 | 3,676 | -438 | 11,971 | -427 | 1,925 | -162 | 3,504 | -42 |
| Coke (STon) | 2,913 | -1,037 | 10,524 | -2,203 | 47,524 | -2,276 | 7,111 | -1,368 | 17,012 | -282 |

What stands out in Table 4.4-15 is that E85 volumes increase while 10 percent ethanol gasoline blends decrease in response to the increased ethanol blended into the gasoline pool. Similarly, ultra low sulfur diesel fuel output decreases in response to the new volume of cellulosic and renewable diesel fuel and biodiesel.

Table 4.4-16 summarizes the change in refinery unit capacities by PADD comparing the primary control case to the AEO 2007 reference case.

### Table 4.4-16.
### Change in Refinery Unit Capacities by PADD
### for the Primary Control Case Relative to the AEO 2007 Reference Case
### (thousand barrels/day)

| | PADD 1 | PADD 2 | PADD 3 | PADD 4/5 ex CA | California | US Total |
|---|---|---|---|---|---|---|
| Crude Tower | 0 | -414 | 0 | 0 | 0 | -414 |
| Vacuum Tower | 0 | -185 | 0 | 0 | 0 | -185 |
| Sats Gas Plant | -12 | 0 | -2 | 0 | 8 | -6 |
| Unsats Gas Plant | 0 | 0 | 0 | 0 | 0 | 0 |
| FCC DeC5 Tower | 0 | 0 | 0 | 0 | 0 | 0 |
| FCC | 0 | 0 | 0 | 0 | 0 | 0 |
| FCC Splitter | 4 | -6 | 0 | 0 | 0 | -2 |
| Hydrocracker | -16 | 0 | 0 | -21 | 0 | -37 |
| H-Oil Unit | 0 | 0 | 0 | 0 | 0 | 0 |
| Delayed Coker | 0 | 0 | 0 | -24 | 0 | -24 |
| Visbreaker | 0 | 0 | 0 | 0 | 0 | 0 |
| Thermal Naphtha Splitter | -1 | -6 | 0 | -1 | 0 | -8 |
| CRU Reformer | 0 | 0 | 0 | 0 | 0 | 0 |
| SRU Reformer | 0 | 0 | 0 | 0 | -5 | -5 |
| BTX Reformer | 0 | 0 | -10 | 0 | 0 | -10 |
| C4 Isomerization | 0 | 0 | 0 | 0 | 1 | 1 |
| C5/C6 Isomerization | 21 | 0 | 0 | 0 | 0 | 21 |
| HF Alkylation | 0 | 0 | 0 | 0 | 0 | 0 |
| H2SO4 Alkylation | -14 | 0 | 0 | 13 | 0 | -2 |
| Dimersol | 0 | 0 | 0 | 0 | 0 | 0 |
| Cat Poly | 6 | 0 | 0 | 0 | 0 | 6 |
| Isooctane | 0 | 0 | 0 | 0 | 0 | 0 |
| DHT - Total | -132 | 0 | -75 | -49 | 0 | -256 |
| DHT 2nd RCT - Total | -117 | -116 | -146 | -51 | -4 | -435 |
| DHT Arom Saturation | 0 | 0 | 0 | 0 | 0 | 0 |
| NHT - Total Fd | 0 | 0 | 0 | 0 | 0 | 0 |
| CGH - Generic | -16 | -23 | -6 | -2 | 0 | -48 |
| CGH - Olefin Sat'n | 0 | 0 | 0 | 0 | 0 | 0 |
| FCCU Fd HDT | 55 | 0 | 0 | 0 | 0 | 55 |
| LSR Splitter | 0 | 0 | 0 | 0 | 0 | 0 |
| LSR Bz Saturator | 0 | 0 | 0 | 0 | 0 | 0 |
| Reformate Saturator | -14 | -4 | 1 | 0 | 0 | -16 |
| Reformate Splitter | -41 | -12 | 4 | 0 | 0 | -49 |
| SDA | 0 | 0 | 0 | 0 | 0 | 0 |
| MTBE | 0 | 0 | 0 | 0 | 0 | 0 |
| TAME | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydrogen Plant - Total MSCF | -88 | -72 | -84 | -71 | 0 | -316 |
| Lube Unit | 0 | 0 | 0 | 0 | 0 | 0 |
| Sulfur Plant | -95 | 0 | 0 | -204 | -69 | -368 |
| Merox Jet | 0 | 0 | 0 | 0 | 0 | 0 |
| Merox Diesel | 0 | 0 | 0 | 0 | 0 | 0 |
| BTX Reformer - Tower feed | 0 | 0 | 0 | 0 | 0 | 0 |
| BTX Reformer - Extract feed | 0 | 0 | 0 | 0 | 0 | 0 |

Most of the capacity throughput changes are negative, reflecting the decreased processing of crude oil and vacuum gas oil and decreased downstream refining units as projected by the refinery model. Another important decrease in refinery unit throughput is the distillate hydrotreater and hydrocracker units which reflect the displacement of petroleum distillate by cellulosic and renewable diesel and biodiesel.

These changes in refinery unit throughputs are associated with changes in capital investments. Table 4.4-17 summarizes the projected change in capital investments between the primary control case and the AEO 2007 reference case.

### Table 4.4-17.
### Change in Refinery Unit Investments by PADD for the Primary Control Case Relative to the AEO 2007 Reference Case
### (million dollars/year)

| | PADD 1 | PADD 2 | PADD 3 | PADD 4/5 ex CA | California | US Total |
|---|---|---|---|---|---|---|
| Crude Tower | 0 | -960 | 0 | 0 | 0 | -960 |
| Vacuum Tower | 0 | -572 | 0 | 0 | 0 | -572 |
| Sats Gas Plant | -67 | 0 | -4 | 0 | 53 | -18 |
| Unsats Gas Plant | -2 | 0 | 0 | 0 | 0 | -2 |
| FCC DeC5 Tower | 0 | 0 | 0 | 0 | 0 | 0 |
| FCC | 0 | 0 | 0 | 0 | 0 | 0 |
| FCC Splitter | 2 | -7 | 0 | 0 | 0 | -5 |
| Hydrocracker | -584 | 0 | 0 | -641 | 0 | -1,225 |
| H-Oil Unit | 0 | 0 | 0 | 0 | 0 | 0 |
| Delayed Coker | 0 | 0 | 0 | -534 | 0 | -534 |
| Visbreaker | 0 | 0 | 0 | 0 | 0 | 0 |
| Thermal Naphtha Splitter | -3 | -7 | 0 | -2 | 0 | -12 |
| CRU Reformer | 0 | 0 | 0 | 0 | 0 | 0 |
| SRU Reformer | 0 | 0 | 0 | 0 | -30 | -30 |
| BTX Reformer | 0 | 0 | -63 | 0 | 0 | -63 |
| C4 Isomerization | 0 | 0 | 0 | 0 | 6 | 6 |
| C5/C6 Isomerization | 187 | 0 | 0 | 0 | 0 | 187 |
| HF Alkylation | 0 | 0 | 0 | 0 | 0 | 0 |
| H2SO4 Alkylation | -246 | 0 | 0 | 246 | 0 | 1 |
| Dimersol | 0 | 0 | 0 | 0 | 0 | 0 |
| Cat Poly | 48 | 0 | 0 | 0 | 0 | 48 |
| Isooctane | 0 | 0 | 0 | 0 | 0 | 0 |
| DHT - Total | -1,364 | 0 | -496 | -531 | 0 | -2,391 |
| DHT 2nd RCT - Total | -905 | -771 | -694 | -308 | -21 | -2,699 |
| DHT Arom Saturation | 0 | 0 | 0 | 0 | 0 | 0 |
| NHT - Total Fd | 0 | 0 | 0 | 0 | 0 | 0 |
| CGH - Generic | -75 | -131 | -60 | -7 | 0 | -274 |
| CGH - Olefin Sat'n | 0 | 0 | 0 | 0 | 0 | 0 |
| FCCU Fd HDT | 695 | 0 | 0 | 0 | 0 | 695 |
| LSR Splitter | 0 | 0 | 0 | 0 | 0 | 0 |
| LSR Bz Saturator | 0 | 0 | 0 | 0 | 0 | 0 |
| Reformate Saturator | -92 | -19 | 5 | 0 | 0 | -105 |
| Reformate Splitter | -53 | -16 | 2 | 0 | 0 | -68 |
| SDA | 0 | 0 | 0 | 0 | 0 | 0 |
| MTBE | 0 | 0 | 0 | 0 | 0 | 0 |
| TAME | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydrogen Plant - Total MSCF | -352 | -221 | -227 | -237 | 0 | -1,038 |
| Lube Unit | 0 | 0 | 0 | 0 | 0 | 0 |
| Sulfur Plant | -3 | 0 | 0 | -2 | -2 | -6 |
| Merox Jet | 0 | 0 | 0 | 0 | 0 | 0 |
| Merox Diesel | 0 | 0 | 0 | 0 | 0 | 0 |
| BTX Reformer - Tower feed | 0 | 0 | -1 | 0 | 0 | -1 |
| BTX Reformer - Extract feed | 0 | 0 | 0 | 0 | 0 | 0 |
| Total | -2,814 | -2,704 | -1,539 | -2,016 | 6 | -9,067 |

Table 4.4-17 shows that incremental to the AEO 2007 reference case, refiners are expected to reduce their capital investments by $9.1 billion under the primary control case. The reduction in capital investments occurs in PADDs 1 through 4 and PADD 5 outside of California. Table 4.4-17 essentially expresses the change in refinery capacity input shown in

Table 4.4-16, but expresses the changes in terms of dollars instead of thousands of barrels per day.

The capital cost decrease in refineries is countered by the capital costs incurred to build new renewable fuels plants and to put into place the distribution system that the new renewable fuels require. The increased use of renewable and alternative fuels would require capital investments in corn and cellulosic ethanol plants, and renewable diesel fuel plants. In addition to producing the fuels, storage and distribution facilities along the whole distribution chain, including at retail, will have to be constructed for these new fuels. In Table 4.4-18, we list the total incremental capital investments that we project would be made for the primary control case incremental to the AEO 2007 reference case. All these capital costs are represented in the summary of costs in Table 4.4-12 either in the per-gallon biofuel production costs, or the per-gallon distribution costs.

**Table 4.4-18.**
**Projected Total U.S. Capital Investments for the Primary Control Case Relative to the AEO 2007 Reference Case**
**(billion dollars)**

| Cost Type | Plant Type | Capital Investments |
|---|---|---|
| Production Costs | Corn Ethanol | 3.9 |
| | Cellulosic Ethanol | 14.3 |
| | Cellulosic Diesel [a] | 68.0 |
| | Renewable Diesel and Algae | 1.1 |
| Distribution Costs | All Ethanol | 8.2 |
| | Cellulosic and Renewable Diesel Fuel | 1.4 |
| | Biodiesel | 1.2 |
| | FFV Costs | 1.8 |
| | Refining | -9.4 |
| Total Capital Investments | | 90.5 |

a The cellulosic diesel fuel capital costs are based on biomass-to-liquids (BTL) technology which is a very capital intensive technology. If other cellulosic biofuel technologies are used which are less capital intensive than BTL technologies, these capital costs would be lower.

Table 4.4-18 shows that the total U.S. incremental capital investments to achieve the RFS2 volumes under the primary control case in 2022 is $90.5 billion. One contributing reason why the capital investments made for renewable fuels technologies is so much more than the decrease in refining industry capital investments is that a part of the decrease in petroleum gasoline supply was from reduced imports. In addition, renewable fuels technologies are more capital intensive per gallon of fuel produced than incremental increases in gasoline and diesel fuel production at refineries.

Table 4.4-19 summarizes the gasoline volume and qualities by different gasoline types for the primary control case, and also, for comparison, lists the same for the AEO 2007 reference case.

### Table 4.4-19.
### Ethanol and Gasoline Volume, Quality and Energy Density by Gasoline Type at the PADD Terminal for the Primary Control Case Relative to the AEO 2007 Reference Case

| | PADD 1 | | PADD 2 | | PADD 3 | | PADD 4/5 ex CA | | CA | | US | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Ref Case | Control | Ref Case | Control | Ref Case | Control | Ref Case | Control | Ref Case | Control | Ref Case | Control |
| RFG | | | | | | | | | | | | |
| Total ('000 BPD) | 1,376,331 | 1,107,710 | 319,080 | 325,776 | 459,343 | 482,832 | 0 | 0 | 1,299,365 | 1,326,631 | 3,454,120 | 3,242,949 |
| Ethanol ('000 BPD) | 139,023 | 111,890 | 32,230 | 32,907 | 46,397 | 48,771 | 0 | 0 | 131,244 | 134,003 | 348,895 | 327,571 |
| RVP (psi) | 10.8 | 10.8 | 10.6 | 10.6 | 9.7 | 9.8 | 0.0 | 0.0 | 9.5 | 9.5 | 10.1 | 10.1 |
| Sulfur (ppm) | 24.4 | 24.6 | 20.0 | 20.5 | 23.2 | 23.4 | 0.0 | 0.0 | 8.8 | 8.5 | 18.0 | 17.4 |
| Density | 258.9 | 258.9 | 258.2 | 258.3 | 259.5 | 259.4 | 0.0 | 0.0 | 258.5 | 258.7 | 258.8 | 258.8 |
| Octane (R+M/2) | 88.1 | 88.3 | 88.0 | 88.0 | 88.0 | 88.0 | 0.0 | 0.0 | 87.6 | 87.6 | 87.9 | 87.9 |
| Aromatics (vol%) | 19.9 | 19.9 | 19.9 | 19.9 | 19.6 | 19.7 | 0.0 | 0.0 | 22.2 | 22.1 | 20.7 | 20.8 |
| Benzene (vol%) | 0.57 | 0.57 | 0.57 | 0.57 | 0.56 | 0.56 | 0.00 | 0.00 | 0.53 | 0.54 | 0.55 | 0.56 |
| Olefins (vol%) | 13.6 | 14.7 | 9.4 | 9.3 | 11.5 | 11.1 | 0.0 | 0.0 | 5.7 | 5.7 | 10.0 | 9.9 |
| Oxygen (wt%) | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 0.0 | 0.0 | 3.7 | 3.7 | 3.7 | 3.7 |
| E200 (vol%) | 55.6 | 55.1 | 58.3 | 57.4 | 53.3 | 52.7 | 0.0 | 0.0 | 58.2 | 58.2 | 56.5 | 56.2 |
| E300 (vol%) | 93.9 | 95.3 | 93.9 | 93.8 | 93.9 | 93.4 | 0.0 | 0.0 | 86.2 | 86.2 | 91.0 | 91.2 |
| Energy (MMBtu/Bbl | 4.947 | 4.961 | 4.924 | 4.935 | 4.981 | 4.990 | 0.000 | 0.000 | 4.994 | 5.002 | 4.967 | 4.979 |
| CG | | | | | | | | | | | | |
| Total ('000 BPD) | 1,830,582 | 1,868,996 | 1,640,138 | 1,545,011 | 1,280,314 | 1,059,721 | 696,861 | 691,193 | 112,988 | 115,359 | 5,560,884 | 5,280,279 |
| Ethanol ('000 BPD) | 134,064 | 188,787 | 165,671 | 156,062 | 129,320 | 107,043 | 70,390 | 69,817 | 11,413 | 11,652 | 510,857 | 533,362 |
| RVP (psi) | 11.4 | 11.8 | 11.6 | 11.5 | 10.7 | 10.4 | 11.4 | 11.4 | 10.6 | 10.6 | 11.3 | 11.3 |
| Sulfur (ppm) | 22.9 | 24.5 | 23.6 | 23.3 | 23.1 | 23.1 | 28.0 | 28.0 | 26.6 | 26.3 | 23.9 | 24.4 |
| Density | 258.9 | 259.5 | 259.1 | 259.1 | 260.5 | 260.1 | 258.1 | 257.9 | 262.7 | 264.1 | 259.3 | 259.4 |
| Octane (R+M/2) | 87.8 | 87.8 | 88.0 | 88.0 | 88.0 | 88.2 | 86.9 | 86.9 | 89.3 | 89.5 | 87.8 | 87.9 |
| Aromatics (vol%) | 23.1 | 22.4 | 22.5 | 22.5 | 22.4 | 21.8 | 15.9 | 15.6 | 26.5 | 28.3 | 21.9 | 21.6 |
| Benzene (vol%) | 0.53 | 0.53 | 0.53 | 0.52 | 0.51 | 0.51 | 1.05 | 1.01 | 0.59 | 0.61 | 0.59 | 0.59 |
| Olefins (vol%) | 13.2 | 14.0 | 11.0 | 11.0 | 13.1 | 12.3 | 8.5 | 7.6 | 17.8 | 18.4 | 12.0 | 12.0 |
| Oxygen (wt%) | 2.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.4 | 3.7 |
| E200 (vol%) | 52.5 | 53.1 | 58.8 | 58.0 | 53.0 | 52.5 | 63.0 | 62.7 | 58.0 | 56.4 | 55.9 | 55.8 |
| E300 (vol%) | 93.9 | 95.3 | 93.9 | 83.8 | 93.9 | 79.5 | 93.9 | 90.6 | 86.2 | 86.2 | 93.7 | 88.0 |
| Energy (MMBtu/Bbl | 4.995 | 4.980 | 4.925 | 4.937 | 4.988 | 5.005 | 0.000 | 4.912 | 4.942 | 4.964 | 4.961 | 4.963 |
| E85 | | | | | | | | | | | | |
| Total ('000 BPD) | 0 | 283,619 | 0 | 129,577 | 0 | 247,459 | 0 | 20,291 | 0 | 0 | 0 | 680,947 |
| Ethanol ('000 BPD) | 0 | 243,490 | 0 | 111,243 | 0 | 212,446 | 0 | 17,420 | 0 | 0 | 0 | 584,599 |
| RVP (psi) | 0.0 | 11.1 | 0.0 | 12.2 | 0.0 | 12.1 | 0.0 | 11.9 | 0.0 | 0.0 | 0.0 | 11.7 |
| Sulfur (ppm) | 0.0 | 9.5 | 0.0 | 8.8 | 0.0 | 8.8 | 0.0 | 8.8 | 0.0 | 0.0 | 0.0 | 9.1 |
| Density | 0.0 | 267.7 | 0.0 | 266.3 | 0.0 | 266.2 | 0.0 | 266.1 | 0.0 | 0.0 | 0.0 | 266.8 |
| Octane (R+M/2) | 0.0 | 107.9 | 0.0 | 108.0 | 0.0 | 108.0 | 0.0 | 107.9 | 0.0 | 0.0 | 0.0 | 107.9 |
| Aromatics (vol%) | 0.0 | 0.6 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.3 |
| Benzene (vol%) | 0.00 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 |
| Olefins (vol%) | 0.0 | 2.4 | 0.0 | 3.0 | 0.0 | 1.8 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2.2 |
| Oxygen (wt%) | 0.0 | 30.6 | 0.0 | 30.8 | 0.0 | 30.8 | 0.0 | 30.8 | 0.0 | 0.0 | 0.0 | 30.7 |
| E200 (vol%) | 0.0 | 128.1 | 0.0 | 130.1 | 0.0 | 129.8 | 0.0 | 129.3 | 0.0 | 0.0 | 0.0 | 129.1 |
| E300 (vol%) | 0.0 | 96.1 | 0.0 | 96.6 | 0.0 | 96.6 | 0.0 | 96.6 | 0.0 | 0.0 | 0.0 | 96.4 |
| Energy (MMBtu/Bbl | 0.000 | 3.628 | 0.000 | 3.599 | 0.000 | 3.597 | 0.000 | 3.594 | 0.000 | 0.000 | 0.000 | 3.610 |
| All Mogas | | | | | | | | | | | | |
| Total BPD | 3,206,913 | 3,260,324 | 1,959,219 | 2,000,364 | 1,739,657 | 1,790,012 | 696,861 | 711,484 | 1,412,353 | 1,441,990 | 9,015,003 | 9,204,175 |
| Ethanol BPD | 273086.9 | 544,167 | 197900.9 | 300,212 | 175717.0 | 368,259 | 70390.0 | 87,238 | 142657.3 | 145,656 | 859752.1 | 1,445,532 |
| RVP | 11.1 | 11.4 | 11.4 | 11.4 | 10.4 | 10.5 | 11.4 | 11.4 | 9.6 | 9.6 | 10.8 | 10.9 |
| Sulfur ppm | 24 | 23 | 23 | 22 | 23 | 21 | 28 | 27 | 10 | 10 | 22 | 21 |
| Density | 258.9 | 260 | 259.0 | 259 | 260.2 | 261 | 258.1 | 258 | 258.9 | 259 | 259.1 | 260 |
| R+M/2 | 87.9 | 89.7 | 88.0 | 89.3 | 88.0 | 90.9 | 86.9 | 87.5 | 87.8 | 87.8 | 87.8 | 89.4 |
| Aromatics | 21.7 | 19.7 | 22.1 | 20.6 | 21.7 | 18.2 | 15.9 | 15.2 | 22.5 | 22.6 | 21.5 | 19.7 |
| Benzene | 0.55 | 0.50 | 0.53 | 0.50 | 0.53 | 0.45 | 1.05 | 0.98 | 0.54 | 0.55 | 0.58 | 0.53 |
| Olefins | 13.4 | 13.2 | 10.7 | 10.2 | 12.7 | 10.6 | 8.5 | 7.4 | 6.7 | 6.7 | 11.2 | 10.6 |
| Oxygen (wt%) | 3.1 | 6.1 | 3.7 | 5.5 | 3.7 | 7.5 | 3.7 | 4.5 | 3.7 | 3.7 | 3.5 | 5.8 |
| E200 | 53.8 | 60.3 | 58.7 | 62.6 | 53.1 | 63.2 | 63.0 | 64.6 | 58.2 | 58.1 | 56.1 | 61.4 |
| E300 | 93.9 | 95.4 | 93.9 | 86.3 | 93.9 | 85.6 | 93.9 | 90.8 | 86.2 | 86.2 | 92.7 | 89.7 |
| Energy (MMBtu/Bbl | 4.974 | 4.856 | 4.925 | 4.850 | 4.986 | 4.806 | 4.913 | 4.874 | 4.990 | 4.999 | 4.963 | 4.869 |

Several very important differences are evident when comparing the U.S. gasoline (mogas) qualities of the primary control case to the AEO 2007 reference case in Table 4.4-19. First, the energy content of the control case gasoline is lower than that of the reference case.

Other obvious changes include decreases in aromatics, benzene, olefins and sulfur. Another important change is the increase in the gasoline pool octane. Since the reference case gasoline pool was compliant in octane, the increased octane of the control case represents octane giveaway. After further review, it is evident that virtually all these changes are caused by the blending of E85 which significantly dilutes these properties in the gasoline blendstock in E85.

### Year-by-Year Costs

To understand entire costs of the increase in renewable fuel use mandated by EISA, their impacts on the U.S. economy, and to compare those costs to the benefits, we estimated the year-by-year costs from 2010, the first year of the RFS2 program, to 2030. We first estimated renewable fuels volumes for each renewable fuels type based on the RFS2 volume standards and based on our projections of which renewable fuels would be used to comply with the standard (see Section 1.2). These volumes represent the increment between the AEO 2007 reference case and the primary control case. Based on AEO 2009, we also estimated the overall gasoline and diesel fuel volumes. Table 4.4-20 below summarizes the projected year-by-year incremental renewable fuel, and total gasoline and diesel fuel volumes.

**Table 4.4-20.**
**Summary of Year-by-Year Volumes**
**for the Primary Control Case Relative to the AEO 2007 Reference Case**
**(Billion Gallons/year)**

| Year | Diesel Fuel Volume | Cellulosic Diesel Fuel | Renewable Diesel Fuel | Biodiesel (all types) | Gasoline Volume | Corn Ethanol | Imported Ethanol | Cellulosic Ethanol |
|---|---|---|---|---|---|---|---|---|
| 2010 | 62.93 | 0.04 | 0.04 | 0.51 | 158.65 | 0.75 | 0.00 | -0.09 |
| 2011 | 63.98 | 0.10 | 0.08 | 0.56 | 162.54 | 1.38 | 0.00 | -0.11 |
| 2012 | 65.47 | 0.20 | 0.08 | 0.71 | 162.15 | 2.01 | 0.00 | -0.10 |
| 2013 | 66.42 | 0.41 | 0.08 | 0.87 | 161.03 | 2.49 | 0.00 | 0.06 |
| 2014 | 66.50 | 0.71 | 0.15 | 1.01 | 159.48 | 3.08 | 0.00 | 0.29 |
| 2015 | 66.65 | 1.22 | 0.15 | 1.13 | 157.14 | 3.69 | 0.00 | 0.67 |
| 2016 | 67.21 | 1.73 | 0.15 | 1.06 | 154.50 | 3.84 | 0.12 | 1.06 |
| 2017 | 67.85 | 2.24 | 0.15 | 1.09 | 152.44 | 3.70 | 0.54 | 1.44 |
| 2018 | 68.57 | 2.85 | 0.15 | 1.13 | 149.84 | 3.51 | 0.97 | 1.90 |
| 2019 | 69.23 | 3.46 | 0.15 | 1.16 | 148.08 | 3.31 | 1.38 | 2.36 |
| 2020 | 69.98 | 4.28 | 0.15 | 1.20 | 145.78 | 3.17 | 1.29 | 2.98 |
| 2021 | 70.59 | 5.50 | 0.15 | 1.24 | 144.14 | 2.93 | 1.19 | 3.90 |
| 2022 | 71.25 | 6.52 | 0.15 | 1.28 | 141.10 | 2.71 | 1.60 | 4.67 |
| 2023 | 72.16 | 6.52 | 0.15 | 1.28 | 141.18 | 2.71 | 1.60 | 4.67 |
| 2024 | 73.17 | 6.52 | 0.15 | 1.28 | 141.80 | 2.71 | 1.60 | 4.67 |
| 2025 | 74.21 | 6.52 | 0.15 | 1.28 | 141.66 | 2.71 | 1.60 | 4.67 |
| 2026 | 75.16 | 6.52 | 0.15 | 1.28 | 141.70 | 2.71 | 1.60 | 4.67 |
| 2027 | 76.07 | 6.52 | 0.15 | 1.28 | 139.74 | 2.71 | 1.60 | 4.67 |
| 2028 | 76.99 | 6.52 | 0.15 | 1.28 | 139.65 | 2.71 | 1.60 | 4.67 |
| 2029 | 77.87 | 6.52 | 0.15 | 1.28 | 138.14 | 2.71 | 1.60 | 4.67 |
| 2030 | 78.97 | 6.52 | 0.15 | 1.28 | 138.59 | 2.71 | 1.60 | 4.67 |

Also for our year-by-year cost analysis, we needed year-by-year estimates of the production and distribution cost for each renewable fuel type. The feedstock costs were available for the years 2012, 2017 and 2022 from FASOM for corn ethanol and soy oil, used for producing biodiesel, with crude oil priced at $116 per barrel. We entered those feedstock costs into the respective cost models and interpolated and extrapolated the production costs for the years provided to develop production costs for the in-between years. For cellulosic ethanol, we assumed the same feedstock costs for all years, but we adjusted the production costs based on our adjusted NREL production costs, interpolating between the years for which we have specific cost data. Imported ethanol costs by year are from Section 4.1 above. Tables 4.4-21 summarize the renewable fuels production costs by year along with the projected crude oil, gasoline and diesel fuel wholesale costs.

**Table 4.4-21.**
**Renewable Fuel Production Costs Used in the Year-by-Year Analysis for the Primary Control Case Relative to the AEO 2007 Reference Case**

| Year | Crude Oil Price ($/bbl) | Wholesale Diesel Fuel Cost (c/gal) | Cellulosic Diesel Fuel Cost (c/gal) | Renewable Diesel Fuel Cost (c/gal) | Biodiesel Fuel Cost (c/gal) | Wholesale Gasoline Cost (c/gal) | Corn Ethanol Cost (c/gal) | Imported Ethanol Cost (c/gal) | Cellulosic Ethanol Cost (c/gal) |
|---|---|---|---|---|---|---|---|---|---|
| 2010 | 49.0 | 154 | 258 | 236 | 261 | 157 | 160 | 158 | 220 |
| 2011 | 62.0 | 198 | 256 | 236 | 264 | 191 | 160 | 157 | 203 |
| 2012 | 72.1 | 232 | 255 | 236 | 227 | 218 | 160 | 156 | 186 |
| 2013 | 81.0 | 262 | 253 | 238 | 227 | 241 | 159 | 155 | 168 |
| 2014 | 88.6 | 288 | 251 | 240 | 225 | 262 | 158 | 154 | 151 |
| 2015 | 96.8 | 315 | 249 | 243 | 226 | 283 | 158 | 153 | 134 |
| 2016 | 101.9 | 333 | 248 | 245 | 228 | 297 | 157 | 153 | 133 |
| 2017 | 106.2 | 347 | 246 | 247 | 232 | 308 | 156 | 152 | 132 |
| 2018 | 110.5 | 362 | 244 | 246 | 234 | 320 | 155 | 152 | 131 |
| 2019 | 112.8 | 369 | 242 | 245 | 235 | 326 | 154 | 152 | 130 |
| 2020 | 114.5 | 375 | 241 | 244 | 238 | 330 | 152 | 151 | 129 |
| 2021 | 115.8 | 380 | 239 | 243 | 241 | 334 | 151 | 151 | 128 |
| 2022 | 116.5 | 383 | 237 | 242 | 244 | 335 | 150 | 150 | 127 |
| 2023 | 117.7 | 386 | 237 | 242 | 244 | 339 | 150 | 150 | 127 |
| 2024 | 118.3 | 388 | 237 | 242 | 244 | 340 | 150 | 149 | 127 |
| 2025 | 116.1 | 380 | 237 | 242 | 244 | 334 | 150 | 149 | 127 |
| 2026 | 117.5 | 385 | 237 | 242 | 244 | 338 | 150 | 149 | 127 |
| 2027 | 119.2 | 391 | 237 | 242 | 244 | 343 | 150 | 149 | 127 |
| 2028 | 121.2 | 398 | 237 | 242 | 244 | 348 | 150 | 149 | 127 |
| 2029 | 121.9 | 400 | 237 | 242 | 244 | 350 | 150 | 149 | 127 |
| 2030 | 124.4 | 409 | 237 | 242 | 244 | 356 | 150 | 149 | 127 |

Based on the volumes and renewable fuels production and distribution costs, we estimated the net cost for the increased volumes of renewable fuels in years other than 2022 and summarized them in Table 4.4-22. We started with the year 2022 costs as our basis. We then adjusted those costs using the volume and price relationship between ethanol and gasoline to estimate the costs in other years. We also calculated the total dollar amount of the subsidies based on the volumes of renewable fuels and the subsidy that applies to each renewable fuel, and what the subsidized cost would be when the subsidies are applied.

### Table 4.4-22.
### Year-by-Year Annual Average and Per-Gallon Costs for Gasoline for the Primary Control Case Relative to the AEO 20007 Reference Case

| | Gasoline Costs | | | | Diesel Fuel Costs | | | |
|---|---|---|---|---|---|---|---|---|
| Year | Total Annual Cost ($MM/yr) | Per-Gallon Cost (c/gal) | Subsidy ($MM/yr) | Subsidized Per-Gallon Cost (c/gal) | Total Annual Cost ($MM/yr) | Per-Gallon Cost (c/gal) | Subsidy ($MM/yr) | Subsidized Per-Gallon Cost (c/gal) |
| 2010 | 456 | 0.3 | 242 | 0.1 | 815 | 1.3 | 602 | 0.3 |
| 2011 | 703 | 0.4 | 511 | 0.1 | 719 | 1.1 | 693 | 0.0 |
| 2012 | 835 | 0.5 | 808 | 0.0 | 377 | 0.6 | 940 | -0.9 |
| 2013 | 831 | 0.5 | 1181 | -0.2 | 152 | 0.2 | 1312 | -1.7 |
| 2014 | 758 | 0.5 | 1678 | -0.6 | -251 | -0.4 | 1771 | -3.0 |
| 2015 | 198 | 0.1 | 2339 | -1.4 | -963 | -1.4 | 2405 | -5.1 |
| 2016 | -229 | -0.1 | 2839 | -2.0 | -1601 | -2.4 | 2797 | -6.5 |
| 2017 | -1110 | -0.7 | 3275 | -2.9 | -2351 | -3.5 | 3343 | -8.4 |
| 2018 | -2076 | -1.4 | 3726 | -3.9 | -3400 | -5.0 | 3992 | -10.8 |
| 2019 | -2825 | -1.9 | 4150 | -4.7 | -4333 | -6.3 | 4640 | -13.0 |
| 2020 | -2922 | -2.0 | 4721 | -5.2 | -5479 | -7.8 | 5504 | -15.7 |
| 2021 | -2936 | -2.0 | 5554 | -5.9 | -7099 | -10.1 | 6779 | -19.7 |
| 2022 | -3349 | -2.4 | 6308 | -6.8 | -8546 | -12.0 | 7849 | -23.0 |
| 2023 | -3545 | -2.5 | 6308 | -7.0 | -8787 | -12.2 | 7849 | -23.1 |
| 2024 | -3640 | -2.6 | 6308 | -7.0 | -8933 | -12.2 | 7849 | -22.9 |
| 2025 | -3285 | -2.3 | 6308 | -6.8 | -8369 | -11.3 | 7849 | -21.9 |
| 2026 | -3512 | -2.5 | 6308 | -6.9 | -8728 | -11.6 | 7849 | -22.1 |
| 2027 | -3769 | -2.7 | 6308 | -7.2 | -9157 | -12.0 | 7849 | -22.4 |
| 2028 | -4097 | -2.9 | 6308 | -7.5 | -9679 | -12.6 | 7849 | -22.8 |
| 2029 | -4199 | -3.0 | 6308 | -7.6 | -9857 | -12.7 | 7849 | -22.7 |
| 2030 | -4589 | -3.3 | 6308 | -7.9 | -10473 | -13.3 | 7849 | -23.2 |

The projected costs in Table 4.4-22 show that in the initial years of 2010 to 2013 for diesel fuel and 2010 to 2015 for gasoline, the per-gallon costs are positive reflecting the generally higher projected production costs for renewable fuels and the lower crude oil prices. After those initial years, the program would accrue a cost savings assuming that the crude oil prices projected by EIA hold true.

#### 4.4.2.1.2 Primary (Mid-Ethanol) Control Case Incremental to the RFS 1 Reference Case

We also assessed the gasoline and diesel fuel costs and other impacts of the primary control case relative to the RFS1 reference case. The costs contained in Table 4.4-23 are reported by different cost components as well as aggregated total and per-gallon costs.

### Table 4.4-23.
### Primary Control Case Costs without Tax Subsidies Relative to the RFS 1 Reference Case

(2007 dollars, 7% ROI before taxes)

| | Gasoline | Diesel Fuel |
|---|---|---|
| Refinery Model Variable Operating Cost $MM/yr | 11,252 | - |
| Amortized Refinery Capital Costs $MM/yr | -1,031 | - |
| Fixed Operating Costs $MM/yr | -284 | - |
| Added Gasoline Transportation Cost $MM/yr | -148 | - |
| Removal of E85 Pricing Effect $MM/yr | -8,338 | - |
| Crude Oil Cost $51 to $116/bbl $MM/yr | -25,884 | - |
| Lower Energy Density $MM/yr | 15,928 | 1,750 |
| Adjustment from Ethanol Price to Cost $MM/yr | 507 | - |
| FFV Costs $MM/yr | 2,370 | |
| Renewable Diesel Cost vs Petroleum Diesel $MM/yr | - | -10,382 |
| Total Costs $MM/yr | -5,628 | -8,632 |
| Refinery Model Variable Operating Cost c/gal | 7.97 | - |
| Amortized Refinery Capital Costs c/gal | -0.73 | - |
| Fixed Operating Costs c/gal | -0.20 | - |
| Added Gasoline Transportation Cost c/gal | -0.10 | - |
| Removal of E85 Pricing Effect c/gal | -5.91 | - |
| Crude Oil Cost $51 to $116/bbl c/gal | -18.34 | - |
| Lower Energy Density c/gal | 11.29 | 2.45 |
| Adjustment from Ethanol Price to Cost c/gal | 0.36 | - |
| FFV Costs c/gal | 1.68 | |
| Renewable Diesel Cost vs Petroleum Diesel c/gal | - | -14.56 |
| Total Costs c/gal | -3.99 | -12.10 |

Our analysis shows that when considering all the costs associated with the expanded use of ethanol for the primary control case relative to the RFS 1 reference case that the cost of gasoline will decrease by $5.6 billion in the year 2022. Expressed as per-gallon costs, these fuel changes will reduce the cost of producing gasoline in the U.S. by 4.0 cents per gallon. The addition of biodiesel, renewable and cellulosic diesel fuel is estimated to reduce the cost of diesel fuel by $8.6 billion in the year 2022, or save 12.1 cents per gallon.

### Table 4.4-24.
### Primary Control Case Costs Reflecting Tax Subsidies Relative to the RFS 1 Reference Case

(2007 dollars, 7% ROI before taxes)

| | Gasoline | Diesel Fuel |
|---|---|---|
| Total Costs $MM/yr | -5,628 | -8,632 |
| Federal Subsidies $MM/yr | -9,075 | -8,026 |
| Revised Total Cost $MM/yr | -14,703 | -16,659 |
| Total Costs c/gal | -3.99 | -12.10 |
| Federal Subsidies c/gal | -6.43 | -11.25 |
| Total Costs c/gal | -10.42 | -23.35 |

Our analysis of the primary control case costs relative to the RFS 1 reference case reflecting the federal tax subsidies would cause a 10.4 cent per gallon decrease in the apparent cost of producing gasoline, and a 23.4 cent decrease in the apparent cost of producing diesel fuel. While this could represent the cost of the renewable fuel use to consumers at retail, it is possible that only a portion of the tax subsidy will be passed along to the consumer. Thus, the price impact at the pump may be somewhere between the values in Tables 4.4-23 and 4.4-24. However, consumers would also pay the full tax subsidy through higher taxes which would offset the cost savings caused by the subsidies.

Table 4.4-25 summarizes the volumetric inputs to refineries in each PADD for this control case and shows the relative changes of the primary control case compared to the RFS 1 reference case. Because of the increased use of biofuels, petroleum inputs would be expected to decrease, and this is confirmed.

**Table 4.4-25.**
**Summary of the Total and Incremental Volumetric Refinery Inputs by PADD for the Primary Control Case Relative to the RFS 1 Reference Case**
**(barrels/day)**

| | PADD 1 | | PADD 2 | | PADD 3 | | PADD 4/5 ex CA | | CA | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case |
| PADD Crude | 1,347,342 | -151,714 | 3,058,241 | -475,740 | 7,117,305 | -241,263 | 1,534,859 | -4,119 | 1,886,357 | -1,136 |
| GTL Naphtha | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| GTL Diesel | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| VGO HS | 0 | 0 | 0 | 0 | 0 | -33,772 | 0 | 0 | 0 | 0 |
| VGO LS | 0 | 0 | 7,920 | -23,914 | 0 | 0 | 0 | 0 | 0 | 0 |
| HS AR (A960) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LS AR (Alg) | 279,819 | 39,889 | 0 | 0 | 738,057 | 21,829 | 0 | 0 | 0 | 0 |
| Normal Butane | 30,814 | 8,329 | 78,293 | 19,185 | 69,363 | -14,040 | 25,526 | -13,917 | 39,573 | 0 |
| Isobutane | 12,582 | 12,582 | 16,476 | -8,390 | 8,234 | 8,234 | 1,178 | -22,245 | 0 | 0 |
| Other | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| MTBE | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Ethanol - E10 | 270,313 | 130,437 | 168,062 | 63,684 | 142,590 | 88,811 | 66,626 | 40,273 | 143,845 | 8,610 |
| Ethanol - E20 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Ethanol - E85 | 575,048 | 575,048 | 332,715 | 332,715 | 361,999 | 361,999 | 60,129 | 60,129 | 46,969 | 46,969 |
| Reformer Feed | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Methanol | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Natural Gas (FOE) | 74,115 | -6,201 | 136,509 | -5,559 | 493,553 | 6,876 | 86,015 | -3,625 | 154,032 | -2,444 |
| Hydrogen (MSCF) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Pentanes Plus | 0 | 0 | 58 | -32,066 | 52,055 | 0 | 0 | -17,467 | 0 | 0 |
| Import CBOB 10% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Import CBOB 20% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Import RBOB 10% | 0 | -200,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Import RBOB 20% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Import Alkylate | 45,167 | 45,167 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Import Raffinate | 3,442 | -61,147 | 0 | 0 | 0 | 0 | 0 | 0 | 45,808 | 0 |
| Import Reformate | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Import FCC Naphtha | 15,980 | 15,980 | 0 | 0 | 11,943 | 11,943 | 18,580 | 18,580 | 0 | 0 |
| Import Lt Naphtha | 0 | 0 | 17,575 | 17,575 | 0 | 0 | 0 | 0 | 584 | 0 |
| Import Hvy Naph | 0 | 0 | 0 | 0 | 41,644 | 0 | 0 | 0 | 0 | 0 |
| Transfer Lt Naphtha | 0 | -23,342 | 0 | -20,822 | 0 | 0 | 0 | 0 | 11,387 | -9,842 |
| Transfer Reformate | 16,658 | 0 | 0 | -14,074 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfer Alkylate | 60,000 | 17,381 | 0 | 0 | 0 | 0 | 0 | 0 | 60,000 | 16,933 |
| Transfer FCC Naphtha | 0 | 0 | 20,822 | 20,822 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfer Raffinate | 0 | 0 | 11,353 | -5,888 | 0 | 0 | 0 | 0 | 60,000 | 11,077 |
| Transfer RBOB 10% | 242,605 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfer RBOB 20% | 0 | 0 | 8,720 | 8,720 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfer CBOB 10% | 1,398,409 | 1,381,833 | 80,262 | 77,306 | 0 | 0 | 6,493 | -19,539 | 0 | 0 |
| Transfer CBOB 20% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Isooctane | 100 | 0 | 100 | 0 | 100 | 0 | 100 | 0 | 16,462 | 2,029 |
| Isooctene | 100 | 0 | 100 | 0 | 100 | 0 | 100 | 0 | 600 | 0 |

The changes in 4.4-25 are similar to those in 4.4-14 except because the new volume of ethanol is larger, some of the differences are larger.

Table 4.4-26 below summarizes the refinery output volumes and changes in refinery output volumes for the primary control case relative to the RFS 1 reference case by PADD.

# Table 4.4-26.
# Summary of Total and Incremental Refinery Outputs by PADD for the Primary Control Case Relative to the RFS 1 Reference Case
# (barrels/day)

| | PADD 1 | | PADD 2 | | PADD 3 | | PADD 4/5 ex CA | | CA | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case |
| Propane | 34,143 | 1,539 | 50,843 | -12,263 | 103,144 | -32,064 | 23,369 | -1,541 | 52,782 | 1,461 |
| Propylene | 18,685 | 0 | 42,525 | 0 | 245,407 | 0 | 2,041 | 0 | 11,774 | 0 |
| Normal Butane | 0 | -7,832 | 0 | -2,370 | 0 | -45,506 | 0 | 0 | 0 | 0 |
| Isobutane | 0 | 0 | 0 | 0 | 0 | -345 | 0 | 0 | 40,012 | 5,009 |
| PC Naphtha | 15,830 | 0 | 40,290 | 0 | 432,937 | 0 | 0 | 0 | 0 | 0 |
| PC Gasoil | 0 | 0 | 455,618 | -108,658 | 157,500 | 0 | 0 | 0 | 0 | 0 |
| CG Reg | 0 | -118,066 | 0 | -852,131 | 0 | -2,020,447 | 0 | -374,129 | 0 | -53,481 |
| CG Prem | 0 | 0 | 0 | 0 | 0 | -416,926 | 0 | -51,984 | 0 | 0 |
| CG E10 Reg | 1,535,198 | 1,516,962 | 1,172,450 | 704,964 | 872,274 | 872,274 | 542,856 | 325,693 | 99,374 | 59,284 |
| CG E10 Prem | 306,669 | 306,669 | 274,765 | 23,409 | 214,485 | 134,887 | 116,742 | 72,990 | 18,928 | 1,105 |
| RFG E10 Reg | 605,554 | -542,443 | 163,150 | -101,096 | 246,042 | -134,362 | 0 | 0 | 1,088,091 | 12,026 |
| RFG E10 Prem | 228,678 | 10,012 | 53,454 | 3,122 | 78,844 | 6,386 | 0 | 0 | 217,676 | 12,712 |
| CG E20 Reg | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| RFG E20 Reg | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| E85 to CG | 74,814 | 74,814 | 270,064 | 270,064 | 253,773 | 253,773 | 70,039 | 70,039 | 0 | 0 |
| E85 to RFG | 595,006 | 595,006 | 117,484 | 117,484 | 167,888 | 167,888 | 0 | 0 | 54,710 | 54,710 |
| Transfer RBOB 10% | 0 | 0 | 0 | 0 | 251,325 | 8,720 | 0 | 0 | 0 | 0 |
| Transfer RBOB 20% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfer CBOB 10% | 0 | 0 | 0 | 0 | 1,485,164 | 1,439,600 | 0 | 0 | 0 | 0 |
| Transfer CBOB 20% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Jet/Kero A (450ppm) | 70,000 | 0 | 138,523 | -3,108 | 936,227 | 0 | 274,537 | 0 | 229,653 | 0 |
| X-Fer Diesel Rundown | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| HSD Gr 76 (0.2%) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LSD Gr 74 (.05%) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| ULSD (15 ppm) | 587,042 | -39,165 | 643,331 | -30,227 | 2,150,901 | 2,423 | 523,035 | -11,120 | 0 | 0 |
| CARB Diesel | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 358,152 | -6,714 |
| X-Fer C5's to Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1% Residual Fuel | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residual Fuel | 68,283 | -21,481 | 67,826 | 8 | 262,834 | 0 | 138,312 | 22,862 | 45,680 | -4,199 |
| Slurry | 30,026 | 3,876 | 67,363 | -19,645 | 112,554 | -4,041 | 12,295 | -4,210 | 29,893 | 1,191 |
| Asphalt & Wax | 86,013 | -5,669 | 198,329 | -11,671 | 157,500 | 0 | 5,250 | 0 | 41,774 | 0 |
| Gasoil | 0 | 0 | 4,895 | 0 | 0 | 0 | 0 | 0 | 9,814 | 0 |
| Lubes | 18,706 | 0 | 17,313 | 0 | 157,500 | 0 | 0 | 0 | 20,149 | 0 |
| Benzene | 11,003 | 0 | 11,003 | 0 | 51,347 | 0 | 0 | 0 | 0 | 0 |
| Toluene | 0 | 0 | 0 | 0 | 34,910 | 0 | 0 | 0 | 0 | 0 |
| Xylenes | 0 | 0 | 0 | 0 | 7,777 | 0 | 0 | 0 | 0 | 0 |
| Cumene | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Other | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Cyclohexane | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfer Raffinate | 0 | 0 | 0 | 0 | 71,353 | 5,190 | 0 | 0 | 0 | 0 |
| Transfer Alkylate | 0 | 0 | 0 | 0 | 120,000 | 34,314 | 0 | 0 | 0 | 0 |
| Transfer Reformate | 0 | 0 | 0 | 0 | 16,658 | 16,658 | 0 | 0 | 0 | 0 |
| Transfer FCC naphtha | 0 | 0 | 0 | 0 | 20,822 | 20,822 | 0 | 0 | 0 | 0 |
| Transfer Lt Naphtha | 0 | 0 | 0 | 0 | 0 | -23,342 | 0 | 0 | 11,387 | -9,842 |
| Transfer Blendstock | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sulfur (STons) | 1,076 | -74 | 3,571 | -630 | 12,042 | -533 | 2,038 | -59 | 3,559 | -10 |
| Coke (STon) | 3,495 | -227 | 10,154 | -3,068 | 48,646 | -2,278 | 7,899 | -790 | 17,358 | 86 |

Table 4.4-27 summarizes the change in refinery unit capacities by PADD comparing the primary control case to the RFS 1 reference case.

### Table 4.4-27.
### Change in Refinery Unit Capacities by PADD
### for the Primary Control Case Relative to the RFS 1 Reference Case
### (thousand barrels/day)

| | PADD 1 | PADD 2 | PADD 3 | PADD 4/5 ex CA | California | US Total |
|---|---|---|---|---|---|---|
| Crude Tower | 0 | -439 | 0 | 0 | 0 | -439 |
| Vacuum Tower | 0 | -196 | 0 | -2 | 0 | -198 |
| Sats Gas Plant | 3 | 0 | -30 | 0 | 9 | -18 |
| Unsats Gas Plant | -2 | 0 | 0 | 0 | 0 | -2 |
| FCC DeC5 Tower | 0 | 0 | 0 | 0 | 0 | 0 |
| FCC | 0 | 0 | 0 | -8 | 0 | -8 |
| FCC Splitter | 2 | -6 | 0 | 0 | 0 | -5 |
| Hydrocracker | -18 | 0 | 0 | -14 | 0 | -33 |
| H-Oil Unit | 0 | 0 | 0 | 0 | 0 | 0 |
| Delayed Coker | 0 | 0 | 0 | -28 | 0 | -28 |
| Visbreaker | 0 | 0 | 0 | 0 | 0 | 0 |
| Thermal Naphtha Splitter | -1 | -6 | 0 | -1 | 0 | -8 |
| CRU Reformer | 0 | 0 | 0 | 0 | 0 | 0 |
| SRU Reformer | 0 | 0 | 0 | 0 | -1 | -1 |
| BTX Reformer | 0 | -10 | -18 | 0 | 0 | -27 |
| C4 Isomerization | 0 | 0 | 0 | 0 | 1 | 1 |
| C5/C6 Isomerization | 26 | 0 | 0 | 0 | 0 | 26 |
| HF Alkylation | 0 | 0 | 0 | 0 | 0 | 0 |
| H2SO4 Alkylation | 1 | 0 | 0 | -5 | 0 | -4 |
| Dimersol | 0 | 0 | 0 | 0 | 0 | 0 |
| Cat Poly | 0 | 0 | 0 | 0 | 0 | 0 |
| Isooctane | 0 | 0 | 0 | 0 | 0 | 0 |
| DHT - Total | -132 | 0 | -103 | -50 | -4 | -290 |
| DHT 2nd RCT - Total | -117 | -153 | -174 | -52 | -4 | -501 |
| DHT Arom Saturation | 0 | 0 | 0 | 0 | 0 | 0 |
| NHT - Total Fd | 0 | 0 | 0 | -4 | 0 | -4 |
| CGH - Generic | -12 | -19 | -19 | -6 | 0 | -57 |
| CGH - Olefin Sat'n | 0 | 0 | 0 | 0 | 0 | 0 |
| FCCU Fd HDT | 37 | 0 | 0 | 0 | 0 | 37 |
| LSR Splitter | 0 | 41 | 38 | 0 | 0 | 80 |
| LSR Bz Saturator | 0 | 0 | 0 | 0 | 0 | 0 |
| Reformate Saturator | -4 | -4 | 1 | 0 | 0 | -7 |
| Reformate Splitter | -12 | -12 | 3 | 0 | 0 | -21 |
| SDA | 0 | 0 | 0 | 0 | 0 | 0 |
| MTBE | 0 | 0 | 0 | 0 | 0 | 0 |
| TAME | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydrogen Plant - Total MSC | -72 | 11 | 109 | -47 | 0 | 1 |
| Lube Unit | 0 | 0 | 0 | 0 | 0 | 0 |
| Sulfur Plant | -128 | 0 | 0 | -204 | -71 | -402 |
| Merox Jet | 0 | 0 | 0 | 0 | 0 | 0 |
| Merox Diesel | 0 | 0 | 0 | 0 | 0 | 0 |
| BTX Reformer - Tower feed | 0 | -1 | -1 | 0 | 0 | -2 |
| BTX Reformer - Extract feed | -1 | 0 | 0 | 0 | 0 | -1 |

These changes in refinery unit throughputs are associated with changes in capital investments. Table 4.4-28 summarizes the projected change in capital investments between the primary control case and the RFS 1 reference case.

### Table 4.4-28.
### Change in Refinery Unit Investments by PADD
### for the Primary Control Case Relative to the RFS 1 Reference Case
### (million dollars/year)

| | PADD 1 | PADD 2 | PADD 3 | PADD 4/5 ex CA | California | US Total |
|---|---|---|---|---|---|---|
| Crude Tower | 0 | -997 | 0 | 0 | 0 | -997 |
| Vacuum Tower | 0 | -591 | 0 | 0 | 0 | -591 |
| Sats Gas Plant | 12 | 0 | -101 | 0 | 55 | -34 |
| Unsats Gas Plant | -10 | 0 | 0 | 0 | 0 | -10 |
| FCC DeC5 Tower | 0 | 0 | 0 | 0 | 0 | 0 |
| FCC | 0 | 0 | 0 | -193 | 0 | -193 |
| FCC Splitter | 1 | -7 | 0 | 0 | 0 | -6 |
| Hydrocracker | -631 | 0 | 0 | -505 | 0 | -1,137 |
| H-Oil Unit | 0 | 0 | 0 | 0 | 0 | 0 |
| Delayed Coker | 0 | 0 | 0 | -592 | 0 | -592 |
| Visbreaker | 0 | 0 | 0 | 0 | 0 | 0 |
| Thermal Naphtha Splitter | -3 | -7 | 0 | -3 | 0 | -13 |
| CRU Reformer | 0 | 0 | 0 | 0 | 0 | 0 |
| SRU Reformer | 0 | 0 | 0 | 0 | -4 | -4 |
| BTX Reformer | 0 | -93 | -231 | 0 | 0 | -324 |
| C4 Isomerization | 0 | 0 | 0 | 0 | 8 | 8 |
| C5/C6 Isomerization | 227 | 0 | 0 | 0 | 0 | 227 |
| HF Alkylation | 0 | 0 | 0 | 0 | 0 | 0 |
| H2SO4 Alkylation | 16 | 0 | 0 | -70 | 0 | -54 |
| Dimersol | 0 | 0 | 0 | 0 | 0 | 0 |
| Cat Poly | -1 | 0 | 0 | 0 | 0 | -1 |
| Isooctane | 0 | 0 | 0 | 0 | 0 | 0 |
| DHT - Total | -1,367 | 0 | -702 | -539 | -96 | -2,703 |
| DHT 2nd RCT - Total | -904 | -998 | -840 | -312 | -21 | -3,076 |
| DHT Arom Saturation | 0 | 0 | 0 | 0 | 0 | 0 |
| NHT - Total Fd | 0 | 0 | 0 | -46 | 0 | -46 |
| CGH - Generic | -58 | -63 | -92 | -25 | 0 | -238 |
| CGH - Olefin Sat'n | 0 | 0 | 0 | 0 | 0 | 0 |
| FCCU Fd HDT | 555 | 0 | 0 | 0 | 0 | 555 |
| LSR Splitter | 0 | 29 | 18 | 0 | 0 | 47 |
| LSR Bz Saturator | 0 | 0 | 0 | 0 | 0 | 0 |
| Reformate Saturator | -46 | -19 | 4 | 0 | 0 | -60 |
| Reformate Splitter | -20 | -16 | 2 | 0 | 0 | -34 |
| SDA | 0 | 0 | 0 | 0 | 0 | 0 |
| MTBE | 0 | 0 | 0 | 0 | 0 | 0 |
| TAME | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydrogen Plant - Total MSC | -255 | 69 | 274 | -171 | 0 | -84 |
| Lube Unit | 0 | 0 | 0 | 0 | 0 | 0 |
| Sulfur Plant | -3 | 0 | 0 | -2 | -2 | -7 |
| Merox Jet | 0 | 0 | 0 | 0 | 0 | 0 |
| Merox Diesel | 0 | 0 | 0 | 0 | 0 | 0 |
| BTX Reformer - Tower feed | 0 | -2 | -1 | 0 | 0 | -3 |
| BTX Reformer - Extract feed | -3 | 0 | 0 | 0 | 0 | -3 |
| Total | -2,491 | -2,694 | -1,669 | -2,459 | -59 | -9,373 |

Table 4.4-28 shows that incremental to the RFS 1 reference case, refiners under the primary control case are expected to reduce their capital investments by $9.4 billion compared to

business as usual.  The reduction in capital investments occurs in PADDs 1 through 4 and PADD 5 outside of California.  Table 4.4-17 essentially expresses the change in refinery capacity input shown in Table 4.4-16, but expresses the changes in terms of dollars instead of thousands of barrels per day.

Table 4.4-29 summarizes the gasoline volume and qualities by different gasoline types for the primary control case, and also, for comparison, lists the same for the RFS 1 reference case.

## Table 4.4-29.
## Ethanol and Gasoline Volume, Quality and Energy Density by Gasoline Type at the PADD Terminal for the Primary Control Case Relative to the RFS 1 Reference Case

| | PADD 1 | | PADD 2 | | PADD 3 | | PADD 4/5 ex CA | | CA | | US | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Ref Case | Control | Ref Case | Control | Ref Case | Control | Ref Case | Control | Ref Case | Control | Ref Case | Control |
| RFG | | | | | | | | | | | | |
| Total ('000 BPD) | 1,366,663 | 1,107,710 | 314,578 | 325,776 | 452,862 | 482,832 | 0 | 0 | 1,281,031 | 1,326,631 | 3,415,134 | 3,242,949 |
| Ethanol ('000 BPD) | 138,034 | 111,890 | 31,773 | 32,907 | 45,739 | 48,771 | 0 | 0 | 129,386 | 134,003 | 344,932 | 327,571 |
| RVP (psi) | 10.7 | 10.8 | 10.3 | 10.6 | 9.6 | 9.8 | 0.0 | 0.0 | 9.5 | 9.5 | 10.1 | 10.1 |
| Sulfur (ppm) | 23.8 | 24.6 | 20.1 | 20.5 | 23.5 | 23.4 | 0.0 | 0.0 | 8.7 | 8.5 | 17.8 | 17.4 |
| Density | 258.5 | 258.9 | 256.2 | 258.3 | 259.1 | 259.4 | 0.0 | 0.0 | 258.5 | 258.7 | 258.4 | 258.8 |
| Octane (R+M/2) | 88.1 | 88.3 | 88.0 | 88.0 | 88.0 | 88.0 | 0.0 | 0.0 | 87.6 | 87.6 | 87.9 | 87.9 |
| Aromatics (vol%) | 19.9 | 19.9 | 18.2 | 19.9 | 19.5 | 19.7 | 0.0 | 0.0 | 22.2 | 22.1 | 20.5 | 20.8 |
| Benzene (vol%) | 0.57 | 0.57 | 0.57 | 0.57 | 0.57 | 0.56 | 0.00 | 0.00 | 0.54 | 0.54 | 0.56 | 0.56 |
| Olefins (vol%) | 13.1 | 14.7 | 8.0 | 9.3 | 9.3 | 11.1 | 0.0 | 0.0 | 5.7 | 5.7 | 9.3 | 9.9 |
| Oxygen (wt%) | 3.7 | 3.7 | 3.8 | 3.7 | 3.7 | 3.7 | 0.0 | 0.0 | 3.7 | 3.7 | 3.7 | 3.7 |
| E200 (vol%) | 55.7 | 55.1 | 62.5 | 57.4 | 54.5 | 52.7 | 0.0 | 0.0 | 58.5 | 58.2 | 57.2 | 56.2 |
| E300 (vol%) | 93.9 | 95.3 | 91.5 | 93.8 | 93.9 | 93.4 | 0.0 | 0.0 | 86.2 | 86.2 | 90.8 | 91.2 |
| Energy (MMBtu/Bbl) | 4.963 | 4.961 | 4.864 | 4.935 | 5.027 | 4.990 | 0.000 | 0.000 | 4.988 | 5.002 | 4.971 | 4.979 |
| CG | | | | | | | | | | | | |
| Total ('000 BPD) | 1,841,024 | 1,868,996 | 1,570,973 | 1,545,011 | 1,262,249 | 1,059,721 | 687,028 | 691,193 | 111,394 | 115,359 | 5,472,668 | 5,280,279 |
| Ethanol ('000 BPD) | 1,842 | 188,787 | 72,606 | 156,062 | 8,040 | 107,043 | 26,352 | 69,817 | 5,849 | 11,652 | 114,689 | 533,362 |
| RVP (psi) | 10.5 | 11.8 | 11.8 | 11.5 | 10.7 | 10.4 | 11.3 | 11.4 | 10.8 | 10.6 | 11.0 | 11.3 |
| Sulfur (ppm) | 27.8 | 24.5 | 25.3 | 23.3 | 27.3 | 23.1 | 24.6 | 28.0 | 26.4 | 26.3 | 26.6 | 24.4 |
| Density | 259.3 | 259.5 | 258.8 | 259.1 | 259.4 | 260.1 | 256.8 | 257.9 | 260.8 | 264.1 | 258.9 | 259.4 |
| Octane (R+M/2) | 88.0 | 87.8 | 88.0 | 88.0 | 88.0 | 88.2 | 86.8 | 86.9 | 88.0 | 89.5 | 87.8 | 87.9 |
| Aromatics (vol%) | 28.7 | 22.4 | 26.3 | 22.5 | 28.4 | 21.8 | 19.3 | 15.6 | 26.8 | 28.3 | 26.7 | 21.6 |
| Benzene (vol%) | 0.65 | 0.53 | 0.64 | 0.52 | 0.65 | 0.51 | 0.80 | 1.01 | 0.62 | 0.61 | 0.67 | 0.59 |
| Olefins (vol%) | 15.2 | 14.0 | 11.2 | 11.0 | 16.0 | 12.3 | 8.0 | 7.6 | 18.6 | 18.4 | 13.4 | 12.0 |
| Oxygen (wt%) | 0.0 | 3.7 | 1.7 | 3.7 | 0.2 | 3.7 | 1.4 | 3.7 | 1.9 | 3.7 | 0.8 | 3.7 |
| E200 (vol%) | 45.2 | 53.1 | 52.9 | 58.0 | 45.9 | 52.5 | 58.9 | 62.7 | 54.5 | 56.4 | 49.5 | 55.8 |
| E300 (vol%) | 93.9 | 95.3 | 91.5 | 83.8 | 93.9 | 79.5 | 93.9 | 90.6 | 86.2 | 86.2 | 93.0 | 88.0 |
| Energy (MMBtu/Bbl) | 5.133 | 4.980 | 5.007 | 4.937 | 5.127 | 5.005 | 5.004 | 4.912 | 4.998 | 4.964 | 5.077 | 4.963 |
| E85 | | | | | | | | | | | | |
| Total ('000 BPD) | 0 | 283,619 | 0 | 129,577 | 0 | 247,459 | 0 | 20,291 | 0 | 0 | 0 | 680,947 |
| Ethanol ('000 BPD) | 0 | 243,490 | 0 | 111,243 | 0 | 212,446 | 0 | 17,420 | 0 | 0 | 0 | 584,599 |
| RVP (psi) | 0.0 | 11.1 | 0.0 | 12.2 | 0.0 | 12.1 | 0.0 | 11.9 | 0.0 | 0.0 | 0.0 | 11.7 |
| Sulfur (ppm) | 0.0 | 9.5 | 0.0 | 8.8 | 0.0 | 8.8 | 0.0 | 8.8 | 0.0 | 0.0 | 0.0 | 9.1 |
| Density | 0.0 | 267.7 | 0.0 | 266.3 | 0.0 | 266.2 | 0.0 | 266.1 | 0.0 | 0.0 | 0.0 | 266.8 |
| Octane (R+M/2) | 0.0 | 107.9 | 0.0 | 108.0 | 0.0 | 108.0 | 0.0 | 107.9 | 0.0 | 0.0 | 0.0 | 107.9 |
| Aromatics (vol%) | 0.0 | 0.6 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.3 |
| Benzene (vol%) | 0.00 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.01 |
| Olefins (vol%) | 0.0 | 2.4 | 0.0 | 3.0 | 0.0 | 1.8 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 2.2 |
| Oxygen (wt%) | 0.0 | 30.6 | 0.0 | 30.8 | 0.0 | 30.8 | 0.0 | 30.8 | 0.0 | 0.0 | 0.0 | 30.7 |
| E200 (vol%) | 0.0 | 128.1 | 0.0 | 130.1 | 0.0 | 129.8 | 0.0 | 129.3 | 0.0 | 0.0 | 0.0 | 129.1 |
| E300 (vol%) | 0.0 | 96.1 | 0.0 | 96.6 | 0.0 | 96.6 | 0.0 | 96.6 | 0.0 | 0.0 | 0.0 | 96.4 |
| Energy (MMBtu/Bbl) | 0.000 | 3.628 | 0.000 | 3.599 | 0.000 | 3.597 | 0.000 | 3.594 | 0.000 | 0.000 | 0.000 | 3.610 |
| All Mogas | | | | | | | | | | | | |
| Total BPD | 3,207,687 | 3,260,324 | 1,885,551 | 2,000,364 | 1,715,111 | 1,790,012 | 687,028 | 711,484 | 1,392,425 | 1,441,990 | 8,887,802 | 9,204,175 |
| Ethanol BPD | 139875.7 | 544,167 | 104378.5 | 300,212 | 53779.6 | 368,259 | 26352.4 | 87,238 | 135235.5 | 145,656 | 459621.7 | 1,445,532 |
| RVP | 10.6 | 11.4 | 11.5 | 11.4 | 10.4 | 10.5 | 11.3 | 11.4 | 9.6 | 9.6 | 10.6 | 10.9 |
| Sulfur ppm | 26.1 | 23.2 | 24.5 | 21.9 | 26.3 | 21.2 | 24.6 | 27.4 | 10.1 | 9.9 | 23.2 | 20.8 |
| Density | 258.9 | 260.0 | 258.4 | 259.5 | 259.3 | 260.8 | 256.8 | 258.1 | 258.7 | 259.2 | 258.7 | 259.8 |
| R+M/2 | 88.0 | 89.7 | 88.0 | 89.3 | 88.0 | 90.9 | 86.8 | 87.5 | 87.7 | 87.8 | 87.8 | 89.4 |
| Aromatics | 24.9 | 19.7 | 24.9 | 20.6 | 26.0 | 18.2 | 19.3 | 15.2 | 22.6 | 22.6 | 24.3 | 19.7 |
| Benzene | 0.62 | 0.50 | 0.63 | 0.50 | 0.63 | 0.45 | 0.80 | 0.98 | 0.55 | 0.55 | 0.63 | 0.53 |
| Olefins | 14.3 | 13.2 | 10.7 | 10.2 | 14.2 | 10.6 | 8.0 | 7.4 | 6.7 | 6.7 | 11.8 | 10.6 |
| Oxygen (wt%) | 1.6 | 6.1 | 2.0 | 5.5 | 1.2 | 7.5 | 1.4 | 4.5 | 3.6 | 3.7 | 1.9 | 5.8 |
| E200 | 49.7 | 60.3 | 54.5 | 62.6 | 48.1 | 63.2 | 58.9 | 64.6 | 58.1 | 58.1 | 52.5 | 61.4 |
| E300 | 93.9 | 95.4 | 91.5 | 86.3 | 93.9 | 85.6 | 93.9 | 90.8 | 86.2 | 86.2 | 92.2 | 89.7 |
| Energy (MMBtu/Bbl) | 5.061 | 4.856 | 4.983 | 4.850 | 5.101 | 4.806 | 5.004 | 4.874 | 4.988 | 4.999 | 5.036 | 4.869 |

### 4.4.2.2 Low Ethanol Control Case

This section contains the tables which summarize the costs and other impacts of the low ethanol control case relative to the AEO 2007 and RFS 1 reference cases.

#### 4.4.2.2.1 Low Ethanol Control Case Incremental to the AEO 2007 Reference Case

This subsection summarizes the costs and other impacts of the low ethanol control case relative to the AEO 2007 reference case.

### Table 4.4-30
### Low Ethanol Control Case Costs without Tax Subsidies Relative to the AEO 2007 Reference Case

(2007 dollars, 7% ROI before taxes)

| | Gasoline | Diesel Fuel |
|---|---|---|
| Refinery Model Variable Operating Cost $MM/yr | 6,066 | - |
| Amortized Refinery Capital Costs $MM/yr | -1,138 | - |
| Fixed Operating Costs $MM/yr | -314 | - |
| Added Gasoline Transportation Cost $MM/yr | -42 | - |
| Removal of E85 Pricing Effect $MM/yr | -3,549 | - |
| Crude Oil Cost $51 to $116/bbl $MM/yr | -7,232 | - |
| Lower Energy Density $MM/yr | 4,098 | 2,254 |
| Adjustment from Ethanol Price to Cost $MM/yr | 648 | - |
| FFV Costs $MM/yr | 791 | |
| Renewable Diesel Cost vs Petroleum Diesel $MM/yr | - | -13,962 |
| Total Costs $MM/yr | -672 | -11,707 |
| Refinery Model Variable Operating Cost c/gal | 4.35 | - |
| Amortized Refinery Capital Costs c/gal | -0.82 | - |
| Fixed Operating Costs c/gal | -0.22 | - |
| Added Gasoline Transportation Cost c/gal | -0.03 | - |
| Removal of E85 Pricing Effect c/gal | -2.54 | - |
| Crude Oil Cost $51 to $116/bbl c/gal | -5.18 | - |
| Lower Energy Density c/gal | 2.94 | 3.16 |
| Adjustment from Ethanol Price to Cost c/gal | 0.46 | - |
| FFV Costs c/gal | 0.57 | |
| Renewable Diesel Cost vs Petroleum Diesel c/gal | - | -19.56 |
| Total Costs c/gal | -0.48 | -16.40 |

### Table 4.4-31.
### Low Ethanol Control Case Costs Reflecting Tax Subsidies Relative to the AEO 2007 Reference Case

(2007 dollars, 7% ROI before taxes)

| | Gasoline | Diesel Fuel |
|---|---|---|
| Total Costs $MM/yr | -672 | -11,707 |
| Federal Subsidies $MM/yr | -1,597 | -10,712 |
| Revised Total Cost $MM/yr | -2,269 | -22,419 |
| Total Costs c/gal | -0.48 | -16.40 |
| Federal Subsidies c/gal | -1.14 | -15.00 |
| Total Costs c/gal | -1.63 | -31.40 |

# Table 4.4-32.
# Summary of the Total and Incremental Volumetric Refinery Inputs by PADD for the Low Ethanol Control Case Relative to the AEO 2007 Reference Case (barrels/day)

| | PADD 1 | | PADD 2 | | PADD 3 | | PADD 4/5 ex CA | | CA | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case |
| PADD Crude | 1,279,888 | -248,492 | 3,227,551 | -230,937 | 6,947,777 | -303,641 | 1,418,700 | -114,904 | 1,842,788 | -46,607 |
| GTL Naphtha | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| GTL Diesel | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| VGO HS | 0 | 0 | 0 | 0 | 11,581 | -32,204 | 0 | 0 | 0 | 0 |
| VGO LS | 0 | 0 | 38,063 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| HS AR (A960) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LS AR (Alg) | 296,982 | 67,329 | 0 | 0 | 738,419 | 32,205 | 0 | 0 | 0 | 0 |
| Normal Butane | 22,485 | 0 | 55,234 | 3,579 | 111,678 | 25,512 | 39,858 | 142 | 39,573 | 0 |
| Isobutane | 9,412 | 8,868 | 15,826 | -7,966 | 617 | 617 | 20,399 | 14,133 | 0 | 0 |
| Other | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| MTBE | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Ethanol - E10 | 319,378 | 46,291 | 200,104 | 2,203 | 157,892 | -17,825 | 68,870 | -1,520 | 144,107 | 1,450 |
| Ethanol - E20 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Ethanol - E85 | 25,821 | 25,821 | 27,311 | 27,311 | 178,439 | 178,439 | 18,976 | 18,976 | 0 | 0 |
| Reformer Feed | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Methanol | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Natural Gas (FOE) | 71,943 | -9,163 | 135,126 | -9,516 | 486,804 | -17,483 | 84,312 | -9,585 | 150,902 | -4,765 |
| Hydrogen (MSCF) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Pentanes Plus | 0 | 0 | 32,124 | 0 | 52,055 | 0 | 18,580 | 0 | 0 | 0 |
| Import CBOB 10% | 241,570 | 235,283 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Import CBOB 20% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Import RBOB 10% | 107,364 | -38,229 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Import RBOB 20% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Import Alkylate | 19,290 | 17,057 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Import Raffinate | 45,299 | -8,228 | 0 | 0 | 0 | 0 | 0 | 0 | 45,808 | 0 |
| Import Reformate | 0 | -8,829 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Import FCC Naphtha | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Import Lt Naphtha | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 584 | 0 |
| Import Hvy Naph | 7,291 | 7,291 | 0 | 0 | 41,644 | 0 | 0 | 0 | 0 | 0 |
| Transfer Lt Naphtha | 39,298 | 34,965 | 0 | 0 | 0 | 0 | 0 | 0 | 22,233 | 3,849 |
| Transfer Reformate | 9,504 | -7,154 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfer Alkylate | 48,790 | -11,210 | 1,609 | 1,609 | 0 | 0 | 0 | 0 | 60,000 | 0 |
| Transfer FCC Naphtha | 2,408 | 2,408 | 20,822 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfer Raffinate | 0 | 0 | 1,066 | -10,571 | 0 | 0 | 0 | 0 | 59,963 | 12,519 |
| Transfer RBOB 10% | 242,605 | 0 | 37,596 | 37,596 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfer RBOB 20% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfer CBOB 10% | 1,289,975 | 153,702 | 114,969 | 60,914 | 0 | 0 | 9,099 | 2,747 | 0 | 0 |
| Transfer CBOB 20% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Isooctane | 6,030 | 5,930 | 100 | 0 | 100 | 0 | 100 | 0 | 13,445 | -1,817 |
| Isooctene | 24,113 | 24,013 | 100 | 0 | 100 | 0 | 100 | 0 | 804 | 204 |

# Table 4.4-33.
# Summary of Total and Incremental Refinery Outputs by PADD for the Low Ethanol Control Case Relative to the AEO 2007 Control Case
## (barrels/day)

| | PADD 1 | | PADD 2 | | PADD 3 | | PADD 4/5 ex CA | | CA | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case |
| Propane | 30,661 | -1,460 | 54,531 | -2,756 | 101,580 | -15,973 | 20,156 | -2,347 | 52,426 | 834 |
| Propylene | 18,685 | 0 | 42,525 | 0 | 245,407 | 0 | 2,041 | 0 | 11,774 | 0 |
| Normal Butane | 6,350 | 1,383 | 2,614 | 1,650 | 22,377 | -11,285 | 0 | 0 | 0 | 0 |
| Isobutane | 0 | 0 | 0 | 0 | 0 | -411 | 0 | 0 | 41,656 | 167 |
| PC Naphtha | 15,830 | 0 | 40,290 | 0 | 432,937 | 0 | 0 | 0 | 0 | 0 |
| PC Gasoil | 0 | 0 | 535,896 | -24,805 | 157,500 | 0 | 0 | 0 | 0 | 0 |
| CG Reg | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CG Prem | 0 | 0 | 0 | 0 | 0 | -182,001 | 0 | 0 | 0 | 0 |
| CG E10 Reg | 1,684,887 | 427,937 | 1,388,234 | 10,518 | 878,511 | -196,953 | 569,190 | -16,174 | 95,872 | 961 |
| CG E10 Prem | 168,009 | 97,675 | 270,485 | 8,063 | 206,925 | 2,075 | 112,627 | 1,129 | 18,261 | 183 |
| RFG E10 Reg | 1,094,702 | -61,416 | 270,743 | 2,715 | 401,267 | 15,419 | 0 | 0 | 1,102,523 | 11,057 |
| RFG E10 Prem | 214,244 | -5,969 | 51,570 | 517 | 76,432 | 2,937 | 0 | 0 | 210,004 | 2,106 |
| CG E20 Reg | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| RFG E20 Reg | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| E85 to CG | 0 | 0 | 31,813 | 31,813 | 207,848 | 207,848 | 22,103 | 22,103 | 0 | 0 |
| E85 to RFG | 30,077 | 30,077 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfer RBOB 10% | 0 | 0 | 0 | 0 | 280,201 | 37,596 | 0 | 0 | 0 | 0 |
| Transfer RBOB 20% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfer CBOB 10% | 0 | 0 | 0 | 0 | 1,414,043 | 217,363 | 0 | 0 | 0 | 0 |
| Transfer CBOB 20% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Jet/Kero A (450ppm) | 70,000 | 0 | 143,275 | 3,194 | 936,227 | 0 | 274,537 | 0 | 229,653 | 0 |
| X-Fer Diesel Rundown to Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| HSD Gr 76 (0.2%) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LSD Gr 74 (.05%) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| ULSD (15 ppm) | 487,798 | -146,819 | 552,466 | -119,705 | 1,937,875 | -198,428 | 448,555 | -84,744 | 0 | 0 |
| CARB Diesel | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 313,223 | -51,127 |
| X-Fer C5's to Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1% Residual Fuel | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residual Fuel | 50,000 | -41,643 | 56,903 | -7,686 | 262,834 | 0 | 115,134 | -7,157 | 49,880 | 0 |
| Slurry | 32,981 | 5,572 | 76,116 | -10,151 | 106,272 | -7,675 | 20,000 | 6,518 | 28,956 | -51 |
| Asphalt & Wax | 91,682 | 0 | 210,000 | 2,314 | 157,500 | 0 | 5,250 | 0 | 41,774 | 0 |
| Gasoil | 0 | 0 | 4,895 | 0 | 0 | 0 | 0 | 0 | 9,814 | 0 |
| Lubes | 18,706 | 0 | 17,313 | 0 | 157,500 | 0 | 0 | 0 | 20,149 | 0 |
| Benzene | 11,003 | 0 | 11,003 | 0 | 51,347 | 0 | 0 | 0 | 0 | 0 |
| Toluene | 0 | 0 | 0 | 0 | 34,910 | 0 | 0 | 0 | 0 | 0 |
| Xylenes | 0 | 0 | 0 | 0 | 7,777 | 0 | 0 | 0 | 0 | 0 |
| Cumene | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Other | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Cyclohexane | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfer Raffinate | 0 | 0 | 0 | 0 | 61,029 | 1,948 | 0 | 0 | 0 | 0 |
| Transfer Alkylate | 0 | 0 | 0 | 0 | 110,399 | -9,601 | 0 | 0 | 0 | 0 |
| Transfer Reformate | 0 | 0 | 0 | 0 | 9,504 | -7,154 | 0 | 0 | 0 | 0 |
| Transfer FCC naphtha | 0 | 0 | 0 | 0 | 34,440 | 13,618 | 0 | 0 | 0 | 0 |
| Transfer Lt Naphtha | 0 | 0 | 0 | 0 | 28,088 | 23,755 | 0 | 0 | 22,233 | 3,849 |
| Transfer Blendstock | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sulfur (STons) | 1,034 | -120 | 3,768 | -345 | 11,741 | -657 | 1,880 | -207 | 3,459 | -86 |
| Coke (STon) | 3,201 | -749 | 10,908 | -1,818 | 46,210 | -3,591 | 7,111 | -1,368 | 16,750 | -544 |

# Table 4.4-34.
# Change in Refinery Unit Capacities by PADD
# for the Low Ethanol Control Case Relative to the AEO 2007 Control Case
# (thousand barrels/day)

| | PADD 1 | PADD 2 | PADD 3 | PADD 4/5 ex CA | California | US Total |
|---|---|---|---|---|---|---|
| Crude Tower | 0 | -175 | 0 | 0 | 0 | -175 |
| Vacuum Tower | 0 | -78 | 0 | 0 | 0 | -78 |
| Sats Gas Plant | -12 | 0 | -13 | 0 | 6 | -18 |
| Unsats Gas Plant | 1 | 0 | 0 | 0 | 0 | 1 |
| FCC DeC5 Tower | 0 | 0 | 0 | 0 | 0 | 0 |
| FCC | 0 | 0 | 0 | 0 | 0 | 0 |
| FCC Splitter | 4 | -6 | 0 | 0 | 0 | -2 |
| Hydrocracker | -16 | 0 | 0 | -33 | 0 | -49 |
| H-Oil Unit | 0 | 0 | 0 | 0 | 0 | 0 |
| Delayed Coker | 0 | 0 | 0 | -24 | 0 | -24 |
| Visbreaker | 0 | 0 | 0 | 0 | 0 | 0 |
| Thermal Naphtha Splitter | -1 | -4 | 0 | -1 | 0 | -6 |
| CRU Reformer | 0 | 0 | 0 | 0 | 0 | 0 |
| SRU Reformer | 0 | 0 | 0 | 0 | -9 | -9 |
| BTX Reformer | 0 | 7 | -6 | 0 | 0 | 1 |
| C4 Isomerization | 0 | 0 | 0 | 0 | 1 | 1 |
| C5/C6 Isomerization | 21 | 0 | 0 | 0 | 0 | 21 |
| HF Alkylation | 0 | 0 | 0 | 0 | 0 | 0 |
| H2SO4 Alkylation | -14 | 0 | 0 | 15 | 0 | 0 |
| Dimersol | 0 | 0 | 0 | 0 | 0 | 0 |
| Cat Poly | 6 | 0 | 0 | 0 | 0 | 6 |
| Isooctane | 0 | 0 | 0 | 0 | 0 | 0 |
| DHT - Total | -136 | 0 | -213 | -61 | 0 | -410 |
| DHT 2nd RCT - Total | -127 | -150 | -220 | -63 | -10 | -571 |
| DHT Arom Saturation | 0 | 0 | 0 | 0 | 0 | 0 |
| NHT - Total Fd | 0 | 0 | 0 | 0 | 0 | 0 |
| CGH - Generic | 24 | -10 | -17 | -3 | 0 | -6 |
| CGH - Olefin Sat'n | 0 | 0 | 0 | 0 | 0 | 0 |
| FCCU Fd HDT | 57 | 0 | 0 | 0 | 0 | 57 |
| LSR Splitter | 0 | 0 | 0 | 0 | 0 | 0 |
| LSR Bz Saturator | 0 | 0 | 0 | 0 | 0 | 0 |
| Reformate Saturator | -14 | -9 | 1 | 0 | 0 | -22 |
| Reformate Splitter | -43 | -27 | 3 | 0 | 0 | -66 |
| SDA | 0 | 0 | 0 | 0 | 0 | 0 |
| MTBE | 0 | 0 | 0 | 0 | 0 | 0 |
| TAME | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydrogen Plant - Total MSC | -79 | -52 | -149 | -101 | 0 | -381 |
| Lube Unit | 0 | 0 | 0 | 0 | 0 | 0 |
| Sulfur Plant | -95 | 0 | 0 | -264 | -73 | -432 |
| Merox Jet | 0 | 0 | 0 | 0 | 0 | 0 |
| Merox Diesel | 0 | 0 | 0 | 0 | 0 | 0 |
| BTX Reformer - Tower feed | 0 | 0 | 0 | 0 | 0 | 0 |
| BTX Reformer - Extract feed | 0 | 0 | 0 | 0 | 0 | 0 |

## Table 4.4-35.
## Change in Refinery Unit Investments by PADD for the Low Ethanol Control Case Relative to the AEO 2007 Control Case (million dollars/year)

| | PADD 1 | PADD 2 | PADD 3 | PADD 4/5 ex CA | California | US Total |
|---|---|---|---|---|---|---|
| Crude Tower | 0 | -372 | 0 | 0 | 0 | -372 |
| Vacuum Tower | 0 | -297 | 0 | 0 | 0 | -297 |
| Sats Gas Plant | -65 | 0 | -24 | 0 | 48 | -41 |
| Unsats Gas Plant | 6 | 0 | 0 | 0 | 0 | 6 |
| FCC DeC5 Tower | 0 | 0 | 0 | 0 | 0 | 0 |
| FCC | 0 | 0 | 0 | 0 | 0 | 0 |
| FCC Splitter | 2 | -7 | 0 | 0 | 0 | -5 |
| Hydrocracker | -584 | 0 | 0 | -891 | 0 | -1,475 |
| H-Oil Unit | 0 | 0 | 0 | 0 | 0 | 0 |
| Delayed Coker | 0 | 0 | 0 | -534 | 0 | -534 |
| Visbreaker | 0 | 0 | 0 | 0 | 0 | 0 |
| Thermal Naphtha Splitter | -3 | -3 | 0 | -2 | 0 | -9 |
| CRU Reformer | 0 | 0 | 0 | 0 | 0 | 0 |
| SRU Reformer | 0 | 0 | 0 | 0 | -66 | -66 |
| BTX Reformer | 0 | 70 | -38 | 0 | 0 | 32 |
| C4 Isomerization | 0 | 0 | 0 | 0 | 5 | 5 |
| C5/C6 Isomerization | 184 | 0 | 0 | 0 | 0 | 184 |
| HF Alkylation | 0 | 0 | 0 | 0 | 0 | 0 |
| H2SO4 Alkylation | -245 | 0 | 0 | 274 | 0 | 29 |
| Dimersol | 0 | 0 | 0 | 0 | 0 | 0 |
| Cat Poly | 48 | 0 | 0 | 0 | 0 | 48 |
| Isooctane | 0 | 0 | 0 | 0 | 0 | 0 |
| DHT - Total | -1,394 | 0 | -1,511 | -606 | 0 | -3,510 |
| DHT 2nd RCT - Total | -949 | -985 | -1,103 | -443 | -57 | -3,536 |
| DHT Arom Saturation | 0 | 0 | 0 | 0 | 0 | 0 |
| NHT - Total Fd | 0 | 0 | 0 | 0 | 0 | 0 |
| CGH - Generic | 157 | -88 | -87 | -12 | 0 | -29 |
| CGH - Olefin Sat'n | 0 | 0 | 0 | 0 | 0 | 0 |
| FCCU Fd HDT | 709 | 0 | 0 | 0 | 0 | 709 |
| LSR Splitter | 0 | 0 | 0 | 0 | 0 | 0 |
| LSR Bz Saturator | 0 | 0 | 0 | 0 | 0 | 0 |
| Reformate Saturator | -94 | -60 | 5 | 0 | 0 | -149 |
| Reformate Splitter | -55 | -36 | 2 | 0 | 0 | -88 |
| SDA | 0 | 0 | 0 | 0 | 0 | 0 |
| MTBE | 0 | 0 | 0 | 0 | 0 | 0 |
| TAME | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydrogen Plant - Total MSC | -324 | -172 | -385 | -363 | 0 | -1,244 |
| Lube Unit | 0 | 0 | 0 | 0 | 0 | 0 |
| Sulfur Plant | -3 | 0 | 0 | -2 | -2 | -7 |
| Merox Jet | 0 | 0 | 0 | 0 | 0 | 0 |
| Merox Diesel | 0 | 0 | 0 | 0 | 0 | 0 |
| BTX Reformer - Tower feed | 0 | 1 | 0 | 0 | 0 | 1 |
| BTX Reformer - Extract feec | 0 | 0 | 0 | 0 | 0 | 0 |
| Total | -2,609 | -1,948 | -3,141 | -2,578 | -72 | -10,349 |

### Table 4.4-36.
### Projected Total U.S. Capital Investments
### for the Low Ethanol Control Case Relative to the AEO 2007 Reference Case
### (billion dollars)

| Cost Type | Plant Type | Capital Investments |
|---|---|---|
| Production Costs | Corn Ethanol | 3.9 |
| | Cellulosic Ethanol | 0 |
| | Cellulosic Diesel [a] | 96.5 |
| | Renewable Diesel and Algae | 1.1 |
| Distribution Costs | All Ethanol | 5.6 |
| | Cellulosic and Renewable Diesel Fuel | 2.0 |
| | Biodiesel | 1.2 |
| | FFV Costs | 0.8 |
| | Refining | -10.3 |
| Total Capital Investments | | 110.0 |

## Table 4.4-37.
## Ethanol and Gasoline Volume, Quality and Energy Density by Gasoline Type at the PADD Terminal for the Low Ethanol Control Case Relative to the AEO 2007 Control Case

| | PADD 1 | | PADD 2 | | PADD 3 | | PADD 4/5 ex CA | | CA | | US | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Ref Case | Control | Ref Case | Control | Ref Case | Control | Ref Case | Control | Ref Case | Control | Ref Case | Control |
| RFG | | | | | | | | | | | | |
| Total ('000 BPD) | 1,376,331 | 1,308,946 | 319,080 | 322,313 | 459,343 | 477,699 | 0 | 0 | 1,299,365 | 1,312,528 | 3,454,120 | 3,421,486 |
| Ethanol ('000 BPD) | 139,023 | 132,217 | 32,230 | 32,557 | 46,397 | 48,252 | 0 | 0 | 131,244 | 132,579 | 348,895 | 345,605 |
| RVP (psi) | 10.8 | 10.7 | 10.6 | 10.6 | 9.7 | 9.7 | 0.0 | 0.0 | 9.5 | 9.5 | 10.1 | 10.1 |
| Sulfur (ppm) | 24.4 | 24.5 | 20.0 | 20.7 | 23.2 | 24.1 | 0.0 | 0.0 | 8.8 | 8.8 | 18.0 | 18.0 |
| Density | 258.9 | 258.6 | 258.2 | 258.2 | 259.5 | 258.5 | 0.0 | 0.0 | 258.5 | 258.7 | 258.8 | 258.6 |
| Octane (R+M/2) | 88.1 | 88.1 | 88.0 | 88.0 | 88.0 | 88.0 | 0.0 | 0.0 | 87.6 | 87.6 | 87.9 | 87.9 |
| Aromatics (vol%) | 19.9 | 19.8 | 19.9 | 19.9 | 19.6 | 18.5 | 0.0 | 0.0 | 22.2 | 22.1 | 20.7 | 20.5 |
| Benzene (vol%) | 0.57 | 0.56 | 0.57 | 0.57 | 0.56 | 0.56 | 0.00 | 0.00 | 0.53 | 0.54 | 0.55 | 0.55 |
| Olefins (vol%) | 13.6 | 14.8 | 9.4 | 9.1 | 11.5 | 11.2 | 0.0 | 0.0 | 5.7 | 5.7 | 10.0 | 10.2 |
| Oxygen (wt%) | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 0.0 | 0.0 | 3.7 | 3.7 | 3.7 | 3.7 |
| E200 (vol%) | 55.6 | 54.8 | 58.3 | 57.6 | 53.3 | 53.7 | 0.0 | 0.0 | 58.2 | 58.3 | 56.5 | 56.3 |
| E300 (vol%) | 93.9 | 82.3 | 93.9 | 91.1 | 93.9 | 93.9 | 0.0 | 0.0 | 86.2 | 86.2 | 91.0 | 86.2 |
| Energy (MMBtu/Bbl) | 4.947 | 4.953 | 4.924 | 4.939 | 4.981 | 4.973 | 0.000 | 0.000 | 4.994 | 5.000 | 4.967 | 4.972 |
| CG | | | | | | | | | | | | |
| Total ('000 BPD) | 1,830,582 | 1,852,896 | 1,640,138 | 1,658,720 | 1,280,314 | 1,085,436 | 696,861 | 681,817 | 112,988 | 114,133 | 5,560,884 | 5,393,001 |
| Ethanol ('000 BPD) | 134,064 | 187,161 | 165,671 | 167,547 | 129,320 | 109,640 | 70,390 | 68,870 | 11,413 | 11,529 | 510,857 | 544,748 |
| RVP (psi) | 11.4 | 11.8 | 11.6 | 11.5 | 10.7 | 10.5 | 11.4 | 11.4 | 10.6 | 10.6 | 11.3 | 11.4 |
| Sulfur (ppm) | 22.9 | 24.2 | 23.6 | 23.6 | 23.1 | 23.0 | 28.0 | 28.0 | 26.6 | 26.0 | 23.9 | 24.3 |
| Density | 258.9 | 258.9 | 259.1 | 258.9 | 260.5 | 259.6 | 258.1 | 257.6 | 262.7 | 263.4 | 259.3 | 259.0 |
| Octane (R+M/2) | 87.8 | 87.7 | 88.0 | 88.0 | 88.0 | 88.1 | 86.9 | 86.9 | 89.3 | 89.4 | 87.8 | 87.8 |
| Aromatics (vol%) | 23.1 | 22.4 | 22.5 | 22.5 | 22.4 | 21.8 | 15.9 | 15.2 | 26.5 | 27.6 | 21.9 | 21.5 |
| Benzene (vol%) | 0.53 | 0.52 | 0.53 | 0.53 | 0.51 | 0.51 | 1.05 | 1.03 | 0.59 | 0.63 | 0.59 | 0.59 |
| Olefins (vol%) | 13.2 | 13.9 | 11.0 | 10.8 | 13.1 | 11.9 | 8.5 | 7.6 | 17.8 | 17.5 | 12.0 | 11.8 |
| Oxygen (wt%) | 2.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.4 | 3.7 |
| E200 (vol%) | 52.5 | 52.9 | 58.8 | 58.5 | 53.0 | 52.5 | 63.0 | 63.1 | 58.0 | 57.2 | 55.9 | 55.9 |
| E300 (vol%) | 93.9 | 79.3 | 93.9 | 84.0 | 93.9 | 79.3 | 93.9 | 91.0 | 86.2 | 86.2 | 93.7 | 82.4 |
| Energy (MMBtu/Bbl) | 4.995 | 4.966 | 4.925 | 4.939 | 4.988 | 4.990 | | 4.907 | 4.942 | 4.946 | 4.961 | 4.955 |
| E85 | | | | | | | | | | | | |
| Total ('000 BPD) | 0 | 30,077 | 0 | 31,813 | 0 | 207,848 | 0 | 22,103 | 0 | 0 | 0 | 291,840 |
| Ethanol ('000 BPD) | 0 | 25,821 | 0 | 27,311 | 0 | 178,439 | 0 | 18,976 | 0 | 0 | 0 | 250,548 |
| RVP (psi) | 0.0 | 12.9 | 0.0 | 12.2 | 0.0 | 12.1 | 0.0 | 11.9 | 0.0 | 0.0 | 0.0 | 12.1 |
| Sulfur (ppm) | 0.0 | 8.9 | 0.0 | 8.8 | 0.0 | 8.8 | 0.0 | 8.8 | 0.0 | 0.0 | 0.0 | 8.8 |
| Density | 0.0 | 266.0 | 0.0 | 266.3 | 0.0 | 266.2 | 0.0 | 266.1 | 0.0 | 0.0 | 0.0 | 266.2 |
| Octane (R+M/2) | 0.0 | 108.1 | 0.0 | 108.0 | 0.0 | 107.9 | 0.0 | 107.9 | 0.0 | 0.0 | 0.0 | 108.0 |
| Aromatics (vol%) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Benzene (vol%) | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Olefins (vol%) | 0.0 | 3.0 | 0.0 | 3.0 | 0.0 | 1.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.5 |
| Oxygen (wt%) | 0.0 | 30.8 | 0.0 | 30.8 | 0.0 | 30.8 | 0.0 | 30.8 | 0.0 | 0.0 | 0.0 | 30.8 |
| E200 (vol%) | 0.0 | 130.1 | 0.0 | 130.1 | 0.0 | 129.7 | 0.0 | 129.3 | 0.0 | 0.0 | 0.0 | 129.7 |
| E300 (vol%) | 0.0 | 96.6 | 0.0 | 96.6 | 0.0 | 96.6 | 0.0 | 96.6 | 0.0 | 0.0 | 0.0 | 96.6 |
| Energy (MMBtu/Bbl) | 0.000 | 3.591 | 0.000 | 3.599 | 0.000 | 3.596 | 0.000 | 3.594 | 0.000 | 0.000 | 0.000 | 3.596 |
| All Mogas | | | | | | | | | | | | |
| Total BPD | 3,206,913 | 3,191,919 | 1,959,219 | 2,012,845 | 1,739,657 | 1,770,983 | 696,861 | 703,921 | 1,412,353 | 1,426,660 | 9,015,003 | 9,106,327 |
| Ethanol BPD | 273,087 | 345,199 | 197,901 | 227,416 | 175,717 | 336,332 | 70,390 | 87,846 | 142,657 | 144,107 | 859,752 | 1,140,900 |
| RVP | 11.1 | 11.4 | 11.4 | 11.4 | 10.4 | 10.5 | 11.4 | 11.4 | 9.6 | 9.6 | 10.8 | 10.9 |
| Sulfur ppm | 24 | 24 | 23 | 23 | 23 | 22 | 28 | 27 | 10 | 10 | 22 | 21 |
| Density | 259 | 259 | 259 | 259 | 260 | 260 | 258 | 258 | 259 | 259 | 259 | 259 |
| R+M/2 | 87.9 | 88.0 | 88.0 | 88.3 | 88.0 | 90.4 | 86.9 | 87.6 | 87.8 | 87.8 | 87.8 | 88.5 |
| Aromatics | 21.7 | 21.1 | 22.1 | 21.7 | 21.7 | 18.3 | 15.9 | 14.8 | 22.5 | 22.6 | 21.5 | 20.4 |
| Benzene | 0.55 | 0.53 | 0.53 | 0.52 | 0.53 | 0.46 | 1.05 | 1.00 | 0.54 | 0.55 | 0.58 | 0.56 |
| Olefins | 13.4 | 14.1 | 10.7 | 10.4 | 12.7 | 10.5 | 8.5 | 7.4 | 6.7 | 6.6 | 11.2 | 10.9 |
| Oxygen (wt%) | 3.1 | 4.0 | 3.7 | 4.2 | 3.7 | 7.0 | 3.7 | 4.6 | 3.7 | 3.7 | 3.5 | 4.6 |
| E200 | 53.8 | 54.4 | 58.7 | 59.5 | 53.1 | 61.9 | 63.0 | 65.2 | 58.2 | 58.2 | 56.1 | 58.4 |
| E300 | 93.9 | 80.7 | 93.9 | 85.3 | 93.9 | 85.3 | 93.9 | 91.2 | 86.2 | 86.2 | 92.7 | 84.3 |
| Energy (MMBtu/Bbl) | 4.974 | 4.948 | 4.925 | 4.918 | 4.986 | 4.822 | 4.913 | 4.866 | 4.990 | 4.995 | 4.963 | 4.918 |

### 4.4.2.2.2 Low Ethanol Control Case Incremental to the RFS 1 Reference Case

This subsection summarizes the gasoline and diesel fuel costs and other impacts of the low ethanol control case relative to the RFS1 reference case.

## Table 4.4-38.
## Low Ethanol Control Case Costs without Tax Subsidies Relative to the RFS 1 Reference Case

(2007 dollars, 7% ROI before taxes)

| | Gasoline | Diesel Fuel |
|---|---|---|
| Refinery Model Variable Operating Cost $MM/yr | 6,289 | - |
| Amortized Refinery Capital Costs $MM/yr | -1,172 | - |
| Fixed Operating Costs $MM/yr | -323 | - |
| Added Gasoline Transportation Cost $MM/yr | -102 | - |
| Removal of E85 Pricing Effect $MM/yr | -3,549 | - |
| Crude Oil Cost $51 to $116/bbl $MM/yr | -17,805 | - |
| Lower Energy Density $MM/yr | 10,917 | 2,283 |
| Adjustment from Ethanol Price to Cost $MM/yr | 1,108 | - |
| FFV Costs $MM/yr | 1,516 | |
| Renewable Diesel Cost vs Petroleum Diesel $MM/yr | - | -14,071 |
| Total Costs $MM/yr | -3,121 | -11,788 |
| Refinery Model Variable Operating Cost c/gal | 4.50 | - |
| Amortized Refinery Capital Costs c/gal | -0.84 | - |
| Fixed Operating Costs c/gal | -0.23 | - |
| Added Gasoline Transportation Cost c/gal | -0.07 | - |
| Removal of E85 Pricing Effect c/gal | -2.54 | - |
| Crude Oil Cost $51 to $116/bbl c/gal | -12.75 | - |
| Lower Energy Density c/gal | 7.82 | 3.19 |
| Adjustment from Ethanol Price to Cost c/gal | 0.79 | - |
| FFV Costs c/gal | 1.09 | |
| Renewable Diesel Cost vs Petroleum Diesel c/gal | - | -19.69 |
| Total Costs c/gal | -2.24 | -16.49 |

## Table 4.4-39.
## Low Ethanol Control Case Costs Reflecting Tax Subsidies Relative to the RFS 1 Reference Case

(2007 dollars, 7% ROI before taxes)

| | Gasoline | Diesel Fuel |
|---|---|---|
| Total Costs $MM/yr | -3,121 | -11,788 |
| Federal Subsidies $MM/yr | -4,358 | -10,794 |
| Revised Total Cost $MM/yr | -7479 | -22,582 |
| Total Costs c/gal | -2.24 | -16.49 |
| Federal Subsidies c/gal | -3.12 | -15.10 |
| Total Costs c/gal | -5.36 | -31.60 |

# Table 4.4-40.
# Summary of the Total and Incremental Volumetric Refinery Inputs by PADD (barrels/day)

| | PADD 1 | | PADD 2 | | PADD 3 | | PADD 4/5 ex CA | | CA | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case |
| PADD Crude | 1,279,888 | -219,169 | 3,227,551 | -306,429 | 6,947,777 | -410,791 | 1,418,700 | -120,278 | 1,842,788 | -44,705 |
| GTL Naphtha | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| GTL Diesel | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| VGO HS | 0 | 0 | 0 | 0 | 11,581 | -22,191 | 0 | 0 | 0 | 0 |
| VGO LS | 0 | 0 | 38,063 | 6,229 | 0 | 0 | 0 | 0 | 0 | 0 |
| HS AR (A960) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LS AR (Alg) | 296,982 | 57,053 | 0 | 0 | 738,419 | 22,191 | 0 | 0 | 0 | 0 |
| Normal Butane | 22,485 | 0 | 55,234 | -3,874 | 111,678 | 28,274 | 39,858 | 415 | 39,573 | 0 |
| Isobutane | 9,412 | 9,412 | 15,826 | -9,041 | 617 | 617 | 20,399 | -3,024 | 0 | 0 |
| Other | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| MTBE | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Ethanol - E10 | 319,378 | 179,502 | 200,104 | 95,726 | 157,892 | 104,113 | 68,870 | 42,518 | 144,107 | 8,872 |
| Ethanol - E20 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Ethanol - E85 | 25,821 | 25,821 | 27,311 | 27,311 | 178,439 | 178,439 | 18,976 | 18,976 | 0 | 0 |
| Reformer Feed | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Methanol | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Natural Gas (FOE) | 71,943 | -8,373 | 135,126 | -6,941 | 486,804 | 126 | 84,312 | -5,329 | 150,902 | -5,574 |
| Hydrogen (MSCF) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Pentanes Plus | 0 | 0 | 32,124 | 0 | 52,055 | 0 | 18,580 | 1,113 | 0 | 0 |
| Import CBOB 10% | 241,570 | 241,570 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Import CBOB 20% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Import RBOB 10% | 107,364 | -92,636 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Import RBOB 20% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Import Alkylate | 19,290 | 19,290 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Import Raffinate | 45,299 | -19,291 | 0 | 0 | 0 | 0 | 0 | 0 | 45,808 | 0 |
| Import Reformate | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Import FCC Naphtha | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Import Lt Naphtha | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 584 | 0 |
| Import Hvy Naph | 7,291 | 7,291 | 0 | 0 | 41,644 | 0 | 0 | 0 | 0 | 0 |
| Transfer Lt Naphtha | 39,298 | 15,956 | 0 | -20,822 | 0 | 0 | 0 | 0 | 22,233 | 1,004 |
| Transfer Reformate | 9,504 | -7,154 | 0 | -14,074 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfer Alkylate | 48,790 | 6,171 | 1,609 | 1,609 | 0 | 0 | 0 | 0 | 60,000 | 16,933 |
| Transfer FCC Naphtha | 2,408 | 2,408 | 20,822 | 20,822 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfer Raffinate | 0 | 0 | 1,066 | -16,175 | 0 | 0 | 0 | 0 | 59,963 | 11,040 |
| Transfer RBOB 10% | 242,605 | 0 | 37,596 | 37,596 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfer RBOB 20% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfer CBOB 10% | 1,289,975 | 1,273,399 | 114,969 | 112,012 | 0 | 0 | 9,099 | -16,933 | 0 | 0 |
| Transfer CBOB 20% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Isooctane | 6,030 | 5,930 | 100 | 0 | 100 | 0 | 100 | 0 | 13,445 | -988 |
| Isooctene | 24,113 | 24,013 | 100 | 0 | 100 | 0 | 100 | 0 | 804 | 204 |

# Table 4.4-41.
# Summary of Total and Incremental Refinery Outputs by PADD for the Low Ethanol Control Case Relative to the RFS 1 Control Case
# (barrels/day)

| | PADD 1 | | PADD 2 | | PADD 3 | | PADD 4/5 ex CA | | CA | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case |
| Propane | 30,661 | -1,943 | 54,531 | -8,575 | 101,580 | -33,628 | 20,156 | -4,754 | 52,426 | 1,106 |
| Propylene | 18,685 | 0 | 42,525 | 0 | 245,407 | 0 | 2,041 | 0 | 11,774 | 0 |
| Normal Butane | 6,350 | -1,482 | 2,614 | 244 | 22,377 | -23,129 | 0 | 0 | 0 | 0 |
| Isobutane | 0 | 0 | 0 | 0 | 0 | -345 | 0 | 0 | 41,656 | 6,653 |
| PC Naphtha | 15,830 | 0 | 40,290 | 0 | 432,937 | 0 | 0 | 0 | 0 | 0 |
| PC Gasoil | 0 | 0 | 535,896 | -28,380 | 157,500 | 0 | 0 | 0 | 0 | 0 |
| CG Reg | 0 | -118,066 | 0 | -852,131 | 0 | -2,020,447 | 0 | -374,129 | 0 | -53,481 |
| CG Prem | 0 | 0 | 0 | 0 | 0 | -416,926 | 0 | -51,984 | 0 | 0 |
| CG E10 Reg | 1,684,887 | 1,666,651 | 1,388,234 | 920,748 | 878,511 | 878,511 | 569,190 | 352,027 | 95,872 | 55,782 |
| CG E10 Prem | 168,009 | 168,009 | 270,485 | 19,129 | 206,925 | 127,328 | 112,627 | 68,875 | 18,261 | 438 |
| RFG E10 Reg | 1,094,702 | -53,295 | 270,743 | 6,497 | 401,267 | 20,863 | 0 | 0 | 1,102,523 | 26,457 |
| RFG E10 Prem | 214,244 | -4,422 | 51,570 | 1,238 | 76,432 | 3,974 | 0 | 0 | 210,004 | 5,040 |
| CG E20 Reg | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| RFG E20 Reg | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| E85 to CG | 0 | 0 | 31,813 | 31,813 | 207,848 | 207,848 | 22,103 | 22,103 | 0 | 0 |
| E85 to RFG | 30,077 | 30,077 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfer RBOB 10% | 0 | 0 | 0 | 0 | 280,201 | 37,596 | 0 | 0 | 0 | 0 |
| Transfer RBOB 20% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfer CBOB 10% | 0 | 0 | 0 | 0 | 1,414,043 | 1,368,478 | 0 | 0 | 0 | 0 |
| Transfer CBOB 20% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Jet/Kero A (450ppm) | 70,000 | 0 | 143,275 | 1,643 | 936,227 | 0 | 274,537 | 0 | 229,653 | 0 |
| X-Fer Diesel Rundown | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| HSD Gr 76 (0.2%) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LSD Gr 74 (.05%) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| ULSD (15 ppm) | 487,798 | -138,408 | 552,466 | -121,092 | 1,937,875 | -210,603 | 448,555 | -85,599 | 0 | 0 |
| CARB Diesel | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 313,223 | -51,643 |
| X-Fer C5's to Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1% Residual Fuel | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residual Fuel | 50,000 | -39,764 | 56,903 | -10,915 | 262,834 | 0 | 115,134 | -316 | 49,880 | 0 |
| Slurry | 32,981 | 6,831 | 76,116 | -10,892 | 106,272 | -10,322 | 20,000 | 3,494 | 28,956 | 254 |
| Asphalt & Wax | 91,682 | 0 | 210,000 | 0 | 157,500 | 0 | 5,250 | 0 | 41,774 | 0 |
| Gasoil | 0 | 0 | 4,895 | 0 | 0 | 0 | 0 | 0 | 9,814 | 0 |
| Lubes | 18,706 | 0 | 17,313 | 0 | 157,500 | 0 | 0 | 0 | 20,149 | 0 |
| Benzene | 11,003 | 0 | 11,003 | 0 | 51,347 | 0 | 0 | 0 | 0 | 0 |
| Toluene | 0 | 0 | 0 | 0 | 34,910 | 0 | 0 | 0 | 0 | 0 |
| Xylenes | 0 | 0 | 0 | 0 | 7,777 | 0 | 0 | 0 | 0 | 0 |
| Cumene | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Other | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Cyclohexane | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfer Raffinate | 0 | 0 | 0 | 0 | 61,029 | -5,135 | 0 | 0 | 0 | 0 |
| Transfer Alkylate | 0 | 0 | 0 | 0 | 110,399 | 24,713 | 0 | 0 | 0 | 0 |
| Transfer Reformate | 0 | 0 | 0 | 0 | 9,504 | 9,504 | 0 | 0 | 0 | 0 |
| Transfer FCC naphtha | 0 | 0 | 0 | 0 | 34,440 | 34,440 | 0 | 0 | 0 | 0 |
| Transfer Lt Naphtha | 0 | 0 | 0 | 0 | 28,088 | 4,746 | 0 | 0 | 22,233 | 1,004 |
| Transfer Blendstock | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sulfur (STons) | 1,034 | -115 | 3,768 | -433 | 11,741 | -834 | 1,880 | -216 | 3,459 | -110 |
| Coke (STon) | 3,201 | -520 | 10,908 | -2,313 | 46,210 | -4,714 | 7,111 | -1,577 | 16,750 | -523 |

# Table 4.4-42.
# Change in Refinery Unit Capacities by PADD
# for the Low Ethanol Control Case Relative to the RFS 1 Control Case
# (thousand barrels/day)

| | PADD 1 | PADD 2 | PADD 3 | PADD 4/5 ex CA | California | US Total |
|---|---|---|---|---|---|---|
| Crude Tower | 0 | -200 | 0 | 0 | 0 | -200 |
| Vacuum Tower | 0 | -89 | 0 | -2 | 0 | -92 |
| Sats Gas Plant | 4 | 0 | -40 | 0 | 7 | -29 |
| Unsats Gas Plant | 0 | 0 | 0 | 0 | 0 | 0 |
| FCC DeC5 Tower | 0 | 0 | 0 | 0 | 0 | 0 |
| FCC | 0 | 0 | 0 | -8 | 0 | -8 |
| FCC Splitter | 2 | -6 | 0 | 0 | 0 | -5 |
| Hydrocracker | -18 | 0 | 0 | -26 | 0 | -45 |
| H-Oil Unit | 0 | 0 | 0 | 0 | 0 | 0 |
| Delayed Coker | 0 | 0 | 0 | -28 | 0 | -28 |
| Visbreaker | 0 | 0 | 0 | 0 | 0 | 0 |
| Thermal Naphtha Splitter | -1 | -4 | 0 | -1 | 0 | -6 |
| CRU Reformer | 0 | 0 | 0 | 0 | 0 | 0 |
| SRU Reformer | 0 | 0 | 0 | 0 | -5 | -5 |
| BTX Reformer | 0 | -3 | -14 | 0 | 0 | -16 |
| C4 Isomerization | 0 | 0 | 0 | 0 | 1 | 1 |
| C5/C6 Isomerization | 25 | 0 | 0 | 0 | 0 | 25 |
| HF Alkylation | 0 | 0 | 0 | 0 | 0 | 0 |
| H2SO4 Alkylation | 1 | 0 | 0 | -3 | 0 | -2 |
| Dimersol | 0 | 0 | 0 | 0 | 0 | 0 |
| Cat Poly | 0 | 0 | 0 | 0 | 0 | 0 |
| Isooctane | 0 | 0 | 0 | 0 | 0 | 0 |
| DHT - Total | -137 | 0 | -241 | -62 | -4 | -444 |
| DHT 2nd RCT - Total | -126 | -187 | -248 | -64 | -10 | -637 |
| DHT Arom Saturation | 0 | 0 | 0 | 0 | 0 | 0 |
| NHT - Total Fd | 0 | 0 | 0 | -4 | 0 | -4 |
| CGH - Generic | 28 | -6 | -30 | -7 | 0 | -15 |
| CGH - Olefin Sat'n | 0 | 0 | 0 | 0 | 0 | 0 |
| FCCU Fd HDT | 39 | 0 | 0 | 0 | 0 | 39 |
| LSR Splitter | 0 | 41 | 38 | 0 | 0 | 80 |
| LSR Bz Saturator | 0 | 0 | 0 | 0 | 0 | 0 |
| Reformate Saturator | -4 | -9 | 1 | 0 | 0 | -13 |
| Reformate Splitter | -13 | -27 | 3 | 0 | 0 | -38 |
| SDA | 0 | 0 | 0 | 0 | 0 | 0 |
| MTBE | 0 | 0 | 0 | 0 | 0 | 0 |
| TAME | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydrogen Plant - Total MSCF | -62 | 31 | 44 | -77 | 0 | -64 |
| Lube Unit | 0 | 0 | 0 | 0 | 0 | 0 |
| Sulfur Plant | -128 | 0 | 0 | -264 | -75 | -467 |
| Merox Jet | 0 | 0 | 0 | 0 | 0 | 0 |
| Merox Diesel | 0 | 0 | 0 | 0 | 0 | 0 |
| BTX Reformer - Tower feed | 0 | -1 | 0 | 0 | 0 | -1 |
| BTX Reformer - Extract feed | -1 | 0 | 0 | 0 | 0 | -1 |

# Table 4.4-43.
# Change in Refinery Unit Investments by PADD
# for the Low Ethanol Control Case Relative to the RFS 1 Control Case
# (million dollars/year)

| | PADD 1 | PADD 2 | PADD 3 | PADD 4/5 ex CA | California | US Total |
|---|---|---|---|---|---|---|
| Crude Tower | 0 | -408 | 0 | 0 | 0 | -408 |
| Vacuum Tower | 0 | -317 | 0 | 0 | 0 | -317 |
| Sats Gas Plant | 14 | 0 | -120 | 0 | 50 | -57 |
| Unsats Gas Plant | -1 | 0 | 0 | 0 | 0 | -1 |
| FCC DeC5 Tower | 0 | 0 | 0 | 0 | 0 | 0 |
| FCC | 0 | 0 | 0 | -193 | 0 | -193 |
| FCC Splitter | 1 | -7 | 0 | 0 | 0 | -6 |
| Hydrocracker | -631 | 0 | 0 | -755 | 0 | -1,386 |
| H-Oil Unit | 0 | 0 | 0 | 0 | 0 | 0 |
| Delayed Coker | 0 | 0 | 0 | -592 | 0 | -592 |
| Visbreaker | 0 | 0 | 0 | 0 | 0 | 0 |
| Thermal Naphtha Splitter | -3 | -3 | 0 | -3 | 0 | -10 |
| CRU Reformer | 0 | 0 | 0 | 0 | 0 | 0 |
| SRU Reformer | 0 | 0 | 0 | 0 | -40 | -40 |
| BTX Reformer | 0 | -22 | -206 | 0 | 0 | -229 |
| C4 Isomerization | 0 | 0 | 0 | 0 | 7 | 7 |
| C5/C6 Isomerization | 224 | 0 | 0 | 0 | 0 | 224 |
| HF Alkylation | 0 | 0 | 0 | 0 | 0 | 0 |
| H2SO4 Alkylation | 17 | 0 | 0 | -42 | 0 | -25 |
| Dimersol | 0 | 0 | 0 | 0 | 0 | 0 |
| Cat Poly | -1 | 0 | 0 | 0 | 0 | -1 |
| Isooctane | 0 | 0 | 0 | 0 | 0 | 0 |
| DHT - Total | -1,397 | 0 | -1,716 | -614 | -96 | -3,822 |
| DHT 2nd RCT - Total | -948 | -1,212 | -1,249 | -447 | -57 | -3,913 |
| DHT Arom Saturation | 0 | 0 | 0 | 0 | 0 | 0 |
| NHT - Total Fd | 0 | 0 | 0 | -46 | 0 | -46 |
| CGH - Generic | 175 | -20 | -119 | -29 | 0 | 7 |
| CGH - Olefin Sat'n | 0 | 0 | 0 | 0 | 0 | 0 |
| FCCU Fd HDT | 569 | 0 | 0 | 0 | 0 | 569 |
| LSR Splitter | 0 | 29 | 18 | 0 | 0 | 47 |
| LSR Bz Saturator | 0 | 0 | 0 | 0 | 0 | 0 |
| Reformate Saturator | -48 | -60 | 4 | 0 | 0 | -104 |
| Reformate Splitter | -21 | -36 | 2 | 0 | 0 | -55 |
| SDA | 0 | 0 | 0 | 0 | 0 | 0 |
| MTBE | 0 | 0 | 0 | 0 | 0 | 0 |
| TAME | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydrogen Plant - Total MSCF | -227 | 118 | 117 | -298 | 0 | -290 |
| Lube Unit | 0 | 0 | 0 | 0 | 0 | 0 |
| Sulfur Plant | -3 | 0 | 0 | -2 | -2 | -7 |
| Merox Jet | 0 | 0 | 0 | 0 | 0 | 0 |
| Merox Diesel | 0 | 0 | 0 | 0 | 0 | 0 |
| BTX Reformer - Tower feed | 0 | -1 | -1 | 0 | 0 | -2 |
| BTX Reformer - Extract feed | -3 | 0 | 0 | 0 | 0 | -3 |
| Total | -2,285 | -1,938 | -3,272 | -3,021 | -138 | -10,654 |

## Table 4.4-44.
## Ethanol and Gasoline Volume, Quality and Energy Density by Gasoline Type at the PADD Terminal for the Low Ethanol Control Case Relative to the RFS 1 Control Case

| | PADD 1 | | PADD 2 | | PADD 3 | | PADD 4/5 ex CA | | CA | | US | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Ref Case | Control | Ref Case | Control | Ref Case | Control | Ref Case | Control | Ref Case | Control | Ref Case | Control |
| RFG | | | | | | | | | | | | |
| Total ('000 BPD) | 1,366,663 | 1,308,946 | 314,578 | 322,313 | 452,862 | 477,699 | 0 | 0 | 1,281,031 | 1,312,528 | 3,415,134 | 3,421,486 |
| Ethanol ('000 BPD) | 138,034 | 132,217 | 31,773 | 32,557 | 45,739 | 48,252 | 0 | 0 | 129,386 | 132,579 | 344,932 | 345,605 |
| RVP (psi) | 10.7 | 10.7 | 10.3 | 10.6 | 9.6 | 9.7 | 0.0 | 0.0 | 9.5 | 9.5 | 10.1 | 10.1 |
| Sulfur (ppm) | 23.8 | 24.5 | 20.1 | 20.7 | 23.5 | 24.1 | 0.0 | 0.0 | 8.7 | 8.8 | 17.8 | 18.0 |
| Density | 258.5 | 258.6 | 256.2 | 258.2 | 259.1 | 258.5 | 0.0 | 0.0 | 258.5 | 258.7 | 258.4 | 258.6 |
| Octane (R+M/2) | 88.1 | 88.1 | 88.0 | 88.0 | 88.0 | 88.0 | 0.0 | 0.0 | 87.6 | 87.6 | 87.9 | 87.9 |
| Aromatics (vol%) | 19.9 | 19.8 | 18.2 | 19.9 | 19.5 | 18.5 | 0.0 | 0.0 | 22.2 | 22.1 | 20.5 | 20.5 |
| Benzene (vol%) | 0.57 | 0.56 | 0.57 | 0.57 | 0.57 | 0.56 | 0.00 | 0.00 | 0.54 | 0.54 | 0.56 | 0.55 |
| Olefins (vol%) | 13.1 | 14.8 | 8.0 | 9.1 | 9.3 | 11.2 | 0.0 | 0.0 | 5.7 | 5.7 | 9.3 | 10.2 |
| Oxygen (wt%) | 3.7 | 3.7 | 3.8 | 3.7 | 3.7 | 3.7 | 0.0 | 0.0 | 3.7 | 3.7 | 3.7 | 3.7 |
| E200 (vol%) | 55.7 | 54.8 | 62.5 | 57.6 | 54.5 | 53.7 | 0.0 | 0.0 | 58.5 | 58.3 | 57.2 | 56.3 |
| E300 (vol%) | 93.9 | 82.3 | 91.5 | 91.1 | 93.9 | 93.9 | 0.0 | 0.0 | 86.2 | 86.2 | 90.8 | 86.2 |
| Energy (MMBtu/Bbl) | 4.963 | 4.953 | 4.864 | 4.939 | 5.027 | 4.973 | 0.000 | 0.000 | 4.988 | 5.000 | 4.971 | 4.972 |
| CG | | | | | | | | | | | | |
| Total ('000 BPD) | 1,841,024 | 1,852,896 | 1,570,973 | 1,658,720 | 1,262,249 | 1,085,436 | 687,028 | 681,817 | 111,394 | 114,133 | 5,472,668 | 5,393,001 |
| Ethanol ('000 BPD) | 1,842 | 187,161 | 72,606 | 167,547 | 8,040 | 109,640 | 26,352 | 68,870 | 5,849 | 11,529 | 114,689 | 544,748 |
| RVP (psi) | 10.5 | 11.8 | 11.8 | 11.5 | 10.7 | 10.5 | 11.3 | 11.4 | 10.8 | 10.6 | 11.0 | 11.4 |
| Sulfur (ppm) | 27.8 | 24.2 | 25.3 | 23.6 | 27.3 | 23.0 | 24.6 | 28.0 | 26.4 | 26.0 | 26.6 | 24.3 |
| Density | 259.3 | 258.9 | 258.8 | 258.9 | 259.4 | 259.6 | 256.8 | 257.6 | 260.8 | 263.4 | 258.9 | 259.0 |
| Octane (R+M/2) | 88.0 | 87.7 | 88.0 | 88.0 | 88.0 | 88.1 | 86.8 | 86.9 | 88.0 | 89.4 | 87.8 | 87.8 |
| Aromatics (vol%) | 28.7 | 22.4 | 26.3 | 22.5 | 28.4 | 21.8 | 19.3 | 15.2 | 26.8 | 27.6 | 26.7 | 21.5 |
| Benzene (vol%) | 0.65 | 0.52 | 0.64 | 0.53 | 0.65 | 0.51 | 0.80 | 1.03 | 0.62 | 0.63 | 0.67 | 0.59 |
| Olefins (vol%) | 15.2 | 13.9 | 11.2 | 10.8 | 16.0 | 11.9 | 8.0 | 7.6 | 18.6 | 17.5 | 13.4 | 11.8 |
| Oxygen (wt%) | 0.0 | 3.7 | 1.7 | 3.7 | 0.2 | 3.7 | 1.4 | 3.7 | 1.9 | 3.7 | 0.8 | 3.7 |
| E200 (vol%) | 45.2 | 52.9 | 52.9 | 58.5 | 45.9 | 52.5 | 58.9 | 63.1 | 54.5 | 57.2 | 49.5 | 55.9 |
| E300 (vol%) | 93.9 | 79.3 | 91.5 | 84.0 | 93.9 | 79.3 | 93.9 | 91.0 | 86.2 | 86.2 | 93.0 | 82.4 |
| Energy (MMBtu/Bbl) | 5.133 | 4.966 | 5.007 | 4.939 | 5.127 | 4.990 | 5.004 | 4.907 | 4.998 | 4.946 | 5.077 | 4.955 |
| E85 | | | | | | | | | | | | |
| Total ('000 BPD) | 0 | 30,077 | 0 | 31,813 | 0 | 207,848 | 0 | 22,103 | 0 | 0 | 0 | 291,840 |
| Ethanol ('000 BPD) | 0 | 25,821 | 0 | 27,311 | 0 | 178,439 | 0 | 18,976 | 0 | 0 | 0 | 250,548 |
| RVP (psi) | 0.0 | 12.9 | 0.0 | 12.2 | 0.0 | 12.1 | 0.0 | 11.9 | 0.0 | 0.0 | 0.0 | 12.1 |
| Sulfur (ppm) | 0.0 | 8.9 | 0.0 | 8.8 | 0.0 | 8.8 | 0.0 | 8.8 | 0.0 | 0.0 | 0.0 | 8.8 |
| Density | 0.0 | 266.0 | 0.0 | 266.3 | 0.0 | 266.2 | 0.0 | 266.1 | 0.0 | 0.0 | 0.0 | 266.2 |
| Octane (R+M/2) | 0.0 | 108.1 | 0.0 | 108.0 | 0.0 | 107.9 | 0.0 | 107.9 | 0.0 | 0.0 | 0.0 | 108.0 |
| Aromatics (vol%) | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Benzene (vol%) | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 |
| Olefins (vol%) | 0.0 | 3.0 | 0.0 | 3.0 | 0.0 | 1.3 | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 | 1.5 |
| Oxygen (wt%) | 0.0 | 30.8 | 0.0 | 30.8 | 0.0 | 30.8 | 0.0 | 30.8 | 0.0 | 0.0 | 0.0 | 30.8 |
| E200 (vol%) | 0.0 | 130.1 | 0.0 | 130.1 | 0.0 | 129.7 | 0.0 | 129.3 | 0.0 | 0.0 | 0.0 | 129.7 |
| E300 (vol%) | 0.0 | 96.6 | 0.0 | 96.6 | 0.0 | 96.6 | 0.0 | 96.6 | 0.0 | 0.0 | 0.0 | 96.6 |
| Energy (MMBtu/Bbl) | 0.000 | 3.591 | 0.000 | 3.599 | 0.000 | 3.596 | 0.000 | 3.594 | 0.000 | 0.000 | 0.000 | 3.596 |
| All Mogas | | | | | | | | | | | | |
| Total BPD | 3,207,687 | 3,191,919 | 1,885,551 | 2,012,845 | 1,715,111 | 1,770,983 | 687,028 | 703,921 | 1,392,425 | 1,426,660 | 8,887,802 | 9,106,327 |
| Ethanol BPD | 139,876 | 345,199 | 104,378 | 227,416 | 53,780 | 336,332 | 26,352 | 87,846 | 135,236 | 144,107 | 459,622 | 1,140,900 |
| RVP | 10.6 | 11.4 | 11.5 | 11.4 | 10.4 | 10.5 | 11.3 | 11.4 | 9.6 | 9.6 | 10.6 | 10.9 |
| Sulfur ppm | 26.1 | 24.2 | 24.5 | 22.9 | 26.3 | 21.6 | 24.6 | 27.4 | 10.1 | 10.2 | 23.2 | 21.4 |
| Density | 258.9 | 258.9 | 258.4 | 258.9 | 259.3 | 260.1 | 256.8 | 257.9 | 258.7 | 259.1 | 258.7 | 259.1 |
| R+M/2 | 88.0 | 88.0 | 88.0 | 88.3 | 88.0 | 90.4 | 86.8 | 87.6 | 87.7 | 87.8 | 87.8 | 88.5 |
| Aromatics | 24.9 | 21.1 | 24.9 | 21.7 | 26.0 | 18.3 | 19.3 | 14.8 | 22.6 | 22.6 | 24.3 | 20.4 |
| Benzene | 0.62 | 0.53 | 0.63 | 0.52 | 0.63 | 0.46 | 0.80 | 1.00 | 0.55 | 0.55 | 0.63 | 0.56 |
| Olefins | 14.3 | 14.1 | 10.7 | 10.4 | 14.2 | 10.5 | 8.0 | 7.4 | 6.7 | 6.6 | 11.8 | 10.9 |
| Oxygen (wt%) | 1.6 | 4.0 | 2.0 | 4.2 | 1.2 | 7.0 | 1.4 | 4.6 | 3.6 | 3.7 | 1.9 | 4.6 |
| E200 | 49.7 | 54.4 | 54.5 | 59.5 | 48.1 | 61.9 | 58.9 | 65.2 | 58.1 | 58.2 | 52.5 | 58.4 |
| E300 | 93.9 | 80.7 | 91.5 | 85.3 | 93.9 | 85.3 | 93.9 | 91.2 | 86.2 | 86.2 | 92.2 | 84.3 |
| Energy (MMBtu/Bbl) | 5.061 | 4.948 | 4.983 | 4.918 | 5.101 | 4.822 | 5.004 | 4.866 | 4.988 | 4.995 | 5.036 | 4.918 |

### 4.4.2.3 High Ethanol Control Case

This section summarizes the costs and other impacts of the high ethanol control case relative to the AEO 2007 and RFS 1 reference cases. This case assumes that the cellulosic biofuel standard would be met solely through the production and use of cellulosic ethanol.

### 4.4.2.3.1 High Ethanol Control Case Relative to the AEO 2007 Reference Case

This subsection summarizes the gasoline and diesel fuel costs and other impacts of the high ethanol control case relative to the AEO 2007 reference case.

**Table 4.4-45.**
**High Ethanol Control Case Costs without Tax Subsidies**
**Relative to the AEO 2007 Reference Case**
(2007 dollars, 7% ROI before taxes)

| | Gasoline | Diesel Fuel |
|---|---|---|
| Refinery Model Variable Operating Cost $MM/yr | 23,616 | - |
| Amortized Refinery Capital Costs $MM/yr | -426 | - |
| Fixed Operating Costs $MM/yr | -117 | - |
| Added Gasoline Transportation Cost $MM/yr | -197 | - |
| Removal of E85 Pricing Effect $MM/yr | -19,854 | - |
| Crude Oil Cost $51 to $116/bbl $MM/yr | -34,958 | - |
| Lower Energy Density $MM/yr | 21,728 | 473 |
| Adjustment from Ethanol Price to Cost $MM/yr | -1,866 | - |
| FFV Costs $MM/yr | 6,113 | - |
| Renewable Diesel Cost vs Petroleum Diesel $MM/yr | - | -1,744 |
| Total Costs $MM/yr | -5,961 | -1,271 |
| Refinery Model Variable Operating Cost c/gal | 16.32 | - |
| Amortized Refinery Capital Costs c/gal | -0.29 | - |
| Fixed Operating Costs c/gal | -0.08 | - |
| Added Gasoline Transportation Cost c/gal | -0.14 | - |
| Removal of E85 Pricing Effect c/gal | -13.72 | - |
| Crude Oil Cost $51 to $116/bbl c/gal | -24.16 | - |
| Lower Energy Density c/gal | 15.02 | 0.67 |
| Adjustment from Ethanol Price to Cost c/gal | -1.29 | - |
| FFV Costs c/gal | 4.22 | - |
| Renewable Diesel Cost vs Petroleum Diesel c/gal | - | -2.46 |
| Total Costs c/gal | -4.12 | -1.79 |

**Table 4.4-46.**
**High Ethanol Control Case Costs Reflecting Tax Subsidies**
**Relative to the AEO 2007 Reference Case**
(2007 dollars, 7% ROI before taxes)

| | Gasoline | Diesel Fuel |
|---|---|---|
| Total Costs $MM/yr | -5,961 | -1,271 |
| Federal Subsidies $MM/yr | -17,504 | -1,359 |
| Revised Total Cost $MM/yr | -23,465 | -2,630 |
| Total Costs c/gal | -4.12 | -1.79 |
| Federal Subsidies c/gal | -12.10 | -1.92 |
| Total Costs c/gal | -16.22 | -3.71 |

# Table 4.4-47.

# Summary of the Total and Incremental Volumetric Refinery Inputs by PADD for the High Ethanol Control Case Relative to the AEO 2007 Reference Case

# (barrels/day)

| | PADD 1 | | PADD 2 | | PADD 3 | | PADD 4/5 ex CA | | CA | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case |
| PADD Crude | 1,347,342 | -181,037 | 3,058,241 | -400,248 | 7,117,305 | -134,113 | 1,534,859 | 1,256 | 1,886,357 | -3,037 |
| GTL Naphtha | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| GTL Diesel | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| VGO HS | 0 | 0 | 0 | 0 | 0 | -43,785 | 0 | 0 | 0 | 0 |
| VGO LS | 0 | 0 | 7,920 | -30,143 | 0 | 0 | 0 | 0 | 0 | 0 |
| HS AR (A960) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LS AR (Alg) | 279,819 | 50,165 | 0 | 0 | 738,057 | 31,843 | 0 | 0 | 0 | 0 |
| Normal Butane | 30,814 | 8,329 | 78,293 | 26,638 | 69,363 | -16,802 | 25,526 | -14,190 | 39,573 | 0 |
| Isobutane | 12,582 | 12,038 | 16,476 | -7,315 | 8,234 | 8,234 | 1,178 | -5,088 | 0 | 0 |
| Other | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| MTBE | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Ethanol - E10 | 270,313 | -2,774 | 168,062 | -29,838 | 142,590 | -33,127 | 66,626 | -3,764 | 143,845 | 1,188 |
| Ethanol - E20 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Ethanol - E85 | 575,048 | 575,048 | 332,715 | 332,715 | 361,999 | 361,999 | 60,129 | 60,129 | 46,969 | 46,969 |
| Reformer Feed | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Methanol | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Natural Gas (FOE) | 74,115 | -6,992 | 136,509 | -8,134 | 493,553 | -10,734 | 86,015 | -7,881 | 154,032 | -1,636 |
| Hydrogen (MSCF) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Pentanes Plus | 0 | 0 | 58 | -32,066 | 52,055 | 0 | 0 | -18,580 | 0 | 0 |
| Import CBOB 10% | 0 | -6,286 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Import CBOB 20% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Import RBOB 10% | 0 | -145,593 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Import RBOB 20% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Import Alkylate | 45,167 | 42,933 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Import Raffinate | 3,442 | -50,084 | 0 | 0 | 0 | 0 | 0 | 0 | 45,808 | 0 |
| Import Reformate | 0 | -8,829 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Import FCC Naphtha | 15,980 | 15,980 | 0 | 0 | 11,943 | 11,943 | 18,580 | 18,580 | 0 | 0 |
| Import Lt Naphtha | 0 | 0 | 17,575 | 17,575 | 0 | 0 | 0 | 0 | 584 | 0 |
| Import Hvy Naph | 0 | 0 | 0 | 0 | 41,644 | 0 | 0 | 0 | 0 | 0 |
| Transfer Lt Naphtha | 0 | -4,333 | 0 | 0 | 0 | 0 | 0 | 0 | 11,387 | -6,997 |
| Transfer Reformate | 16,658 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfer Alkylate | 60,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 60,000 | 0 |
| Transfer FCC Naphtha | 0 | 0 | 20,822 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfer Raffinate | 0 | 0 | 11,353 | -284 | 0 | 0 | 0 | 0 | 60,000 | 12,556 |
| Transfer RBOB 10% | 242,605 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfer RBOB 20% | 0 | 0 | 8,720 | 8,720 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfer CBOB 10% | 1,398,409 | 262,136 | 80,262 | 26,208 | 0 | 0 | 6,493 | 142 | 0 | 0 |
| Transfer CBOB 20% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Isooctane | 100 | 0 | 100 | 0 | 100 | 0 | 100 | 0 | 16,462 | 1,200 |
| Isooctene | 100 | 0 | 100 | 0 | 100 | 0 | 100 | 0 | 600 | 0 |

# Table 4.4-48.
# Summary of Total and Incremental Refinery Outputs by PADD for the High Ethanol Control Case Relative to the AEO 2007 Reference Case (barrels/day)

| | PADD 1 | | PADD 2 | | PADD 3 | | PADD 4/5 ex CA | | CA | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case |
| Propane | 34,143 | 2,023 | 50,843 | -6,445 | 103,144 | -14,409 | 23,369 | 866 | 52,782 | 1,190 |
| Propylene | 18,685 | 0 | 42,525 | 0 | 245,407 | 0 | 2,041 | 0 | 11,774 | 0 |
| Normal Butane | 0 | -4,967 | 0 | -965 | 0 | -33,663 | 0 | 0 | 0 | 0 |
| Isobutane | 0 | 0 | 0 | 0 | 0 | -411 | 0 | 0 | 40,012 | -1,478 |
| PC Naphtha | 15,830 | 0 | 40,290 | 0 | 432,937 | 0 | 0 | 0 | 0 | 0 |
| PC Gasoil | 0 | 0 | 455,618 | -105,083 | 157,500 | 0 | 0 | 0 | 0 | 0 |
| CG Reg | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| CG Prem | 0 | 0 | 0 | 0 | 0 | -182,001 | 0 | 0 | 0 | 0 |
| CG E10 Reg | 1,535,198 | 278,248 | 1,172,450 | -205,266 | 872,274 | -203,190 | 542,856 | -42,507 | 99,374 | 4,464 |
| CG E10 Prem | 306,669 | 236,335 | 274,765 | 12,343 | 214,485 | 9,635 | 116,742 | 5,244 | 18,928 | 850 |
| RFG E10 Reg | 605,554 | -550,564 | 163,150 | -104,878 | 246,042 | -139,806 | 0 | 0 | 1,088,091 | -3,375 |
| RFG E10 Prem | 228,678 | 8,465 | 53,454 | 2,401 | 78,844 | 5,349 | 0 | 0 | 217,676 | 9,778 |
| CG E20 Reg | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| RFG E20 Reg | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| E85 to CG | 74,814 | 74,814 | 270,064 | 270,064 | 253,773 | 253,773 | 70,039 | 70,039 | 0 | 0 |
| E85 to RFG | 595,006 | 595,006 | 117,484 | 117,484 | 167,888 | 167,888 | 0 | 0 | 54,710 | 54,710 |
| Transfer RBOB 10% | 0 | 0 | 0 | 0 | 251,325 | 8,720 | 0 | 0 | 0 | 0 |
| Transfer RBOB 20% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfer CBOB 10% | 0 | 0 | 0 | 0 | 1,485,164 | 288,485 | 0 | 0 | 0 | 0 |
| Transfer CBOB 20% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Jet/Kero A (450ppm) | 70,000 | 0 | 138,523 | -1,557 | 936,227 | 0 | 274,537 | 0 | 229,653 | 0 |
| X-Fer Diesel Rundowr | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| HSD Gr 76 (0.2%) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LSD Gr 74 (.05%) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| ULSD (15 ppm) | 587,042 | -47,575 | 643,331 | -28,840 | 2,150,901 | 14,598 | 523,035 | -10,264 | 0 | 0 |
| CARB Diesel | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 358,152 | -6,197 |
| X-Fer C5's to Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1% Residual Fuel | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residual Fuel | 68,283 | -23,360 | 67,826 | 3,237 | 262,834 | 0 | 138,312 | 16,021 | 45,680 | -4,199 |
| Slurry | 30,026 | 2,617 | 67,363 | -18,904 | 112,554 | -1,394 | 12,295 | -1,187 | 29,893 | 886 |
| Asphalt & Wax | 86,013 | -5,669 | 198,329 | -9,357 | 157,500 | 0 | 5,250 | 0 | 41,774 | 0 |
| Gasoil | 0 | 0 | 4,895 | 0 | 0 | 0 | 0 | 0 | 9,814 | 0 |
| Lubes | 18,706 | 0 | 17,313 | 0 | 157,500 | 0 | 0 | 0 | 20,149 | 0 |
| Benzene | 11,003 | 0 | 11,003 | 0 | 51,347 | 0 | 0 | 0 | 0 | 0 |
| Toluene | 0 | 0 | 0 | 0 | 34,910 | 0 | 0 | 0 | 0 | 0 |
| Xylenes | 0 | 0 | 0 | 0 | 7,777 | 0 | 0 | 0 | 0 | 0 |
| Cumene | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Other | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Cyclohexane | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfer Raffinate | 0 | 0 | 0 | 0 | 71,353 | 12,273 | 0 | 0 | 0 | 0 |
| Transfer Alkylate | 0 | 0 | 0 | 0 | 120,000 | 0 | 0 | 0 | 0 | 0 |
| Transfer Reformate | 0 | 0 | 0 | 0 | 16,658 | 0 | 0 | 0 | 0 | 0 |
| Transfer FCC naphtha | 0 | 0 | 0 | 0 | 20,822 | 0 | 0 | 0 | 0 | 0 |
| Transfer Lt Naphtha | 0 | 0 | 0 | 0 | 0 | -4,333 | 0 | 0 | 11,387 | -6,997 |
| Transfer Blendstock | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sulfur (STons) | 1,076 | -78 | 3,571 | -542 | 12,042 | -356 | 2,038 | -49 | 3,559 | 14 |
| Coke (STon) | 3,495 | -455 | 10,154 | -2,572 | 48,646 | -1,154 | 7,899 | -580 | 17,358 | 64 |

## Table 4.4-49.
## Change in Refinery Unit Capacities by PADD for the High Ethanol Control Case Relative to the AEO 2007 Reference Case (thousand barrels/day)

| | PADD 1 | PADD 2 | PADD 3 | PADD 4/5 ex CA | California | US Total |
|---|---|---|---|---|---|---|
| Crude Tower | 0 | -459 | 0 | 0 | 0 | -459 |
| Vacuum Tower | 0 | -205 | 0 | 8 | 0 | -197 |
| Sats Gas Plant | -21 | 0 | -45 | 0 | 10 | -56 |
| Unsats Gas Plant | 1 | 0 | 0 | 0 | 0 | 1 |
| FCC DeC5 Tower | 0 | 0 | 0 | 0 | 0 | 0 |
| FCC | 0 | 0 | 0 | 0 | 0 | 0 |
| FCC Splitter | 1 | -6 | 0 | 0 | 0 | -4 |
| Hydrocracker | 14 | 0 | 0 | -6 | 0 | 7 |
| H-Oil Unit | 0 | 0 | 0 | 0 | 0 | 0 |
| Delayed Coker | 0 | 0 | 0 | -1 | 0 | -1 |
| Visbreaker | 0 | 0 | 0 | 0 | 0 | 0 |
| Thermal Naphtha Splitter | 0 | -6 | 0 | 0 | 0 | -6 |
| CRU Reformer | 0 | 0 | 0 | 0 | 0 | 0 |
| SRU Reformer | 0 | 0 | 0 | 0 | 9 | 9 |
| BTX Reformer | 0 | 7 | -9 | 0 | 0 | -1 |
| C4 Isomerization | 0 | 0 | 0 | 0 | 3 | 3 |
| C5/C6 Isomerization | 16 | 0 | 0 | 0 | 0 | 16 |
| HF Alkylation | 0 | 0 | 0 | 0 | 0 | 0 |
| H2SO4 Alkylation | -27 | 0 | 0 | 0 | 0 | -27 |
| Dimersol | 0 | 0 | 0 | 0 | 0 | 0 |
| Cat Poly | 1 | 0 | 0 | 0 | 0 | 1 |
| Isooctane | 0 | 0 | 0 | 0 | 0 | 0 |
| DHT - Total | -40 | 0 | -19 | -10 | 0 | -69 |
| DHT 2nd RCT - Total | -38 | -52 | -20 | -10 | 0 | -120 |
| DHT Arom Saturation | 0 | 0 | 0 | 0 | 0 | 0 |
| NHT - Total Fd | 0 | 0 | 0 | 2 | 0 | 2 |
| CGH - Generic | 13 | -30 | -6 | 1 | 0 | -23 |
| CGH - Olefin Sat'n | 0 | 0 | 0 | 0 | 0 | 0 |
| FCCU Fd HDT | 24 | 0 | 0 | 0 | 0 | 24 |
| LSR Splitter | 0 | -25 | 0 | 0 | 0 | -25 |
| LSR Bz Saturator | 0 | 0 | 0 | 0 | 0 | 0 |
| Reformate Saturator | -18 | 0 | -2 | 0 | 0 | -20 |
| Reformate Splitter | -54 | 0 | -6 | 0 | 0 | -59 |
| SDA | 0 | 0 | 0 | 0 | 0 | 0 |
| MTBE | 0 | 0 | 0 | 0 | 0 | 0 |
| TAME | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydrogen Plant - Total MSCF | -2 | -43 | -80 | -31 | 0 | -156 |
| Lube Unit | 0 | 0 | 0 | 0 | 0 | 0 |
| Sulfur Plant | -24 | 0 | 0 | -30 | -22 | -76 |
| Merox Jet | 0 | 0 | 0 | 0 | 0 | 0 |
| Merox Diesel | 0 | 0 | 0 | 0 | 0 | 0 |
| BTX Reformer - Tower feed | 0 | 0 | 0 | 0 | 0 | 0 |
| BTX Reformer - Extract feed | 0 | 0 | 0 | 0 | 0 | 0 |

# Table 4.4-50.
# Change in Refinery Unit Investments by PADD for the High Ethanol Control Case Relative to the AEO 2007 Reference Case
## (million dollars/year)

| | PADD 1 | PADD 2 | PADD 3 | PADD 4/5 ex CA | California | US Total |
|---|---|---|---|---|---|---|
| Crude Tower | 0 | -1,121 | 0 | 0 | 0 | -1,121 |
| Vacuum Tower | 0 | -676 | 0 | 70 | 0 | -606 |
| Sats Gas Plant | -107 | 0 | -129 | 0 | 60 | -176 |
| Unsats Gas Plant | 8 | 0 | 0 | 0 | 0 | 8 |
| FCC DeC5 Tower | 0 | 0 | 0 | 0 | 0 | 0 |
| FCC | 0 | 0 | 0 | 0 | 0 | 0 |
| FCC Splitter | 1 | -7 | 0 | 0 | 0 | -6 |
| Hydrocracker | 305 | 0 | 0 | -129 | 0 | 176 |
| H-Oil Unit | 0 | 0 | 0 | 0 | 0 | 0 |
| Delayed Coker | 0 | 0 | 0 | -22 | 0 | -22 |
| Visbreaker | 0 | 0 | 0 | 0 | 0 | 0 |
| Thermal Naphtha Splitter | 0 | -7 | 0 | 0 | 0 | -7 |
| CRU Reformer | 0 | 0 | 0 | 0 | 0 | 0 |
| SRU Reformer | 0 | 0 | 0 | 0 | 45 | 45 |
| BTX Reformer | 0 | 70 | -55 | 0 | 0 | 16 |
| C4 Isomerization | 0 | 0 | 0 | 0 | 20 | 20 |
| C5/C6 Isomerization | 156 | 0 | 0 | 0 | 0 | 156 |
| HF Alkylation | 0 | 0 | 0 | 0 | 0 | 0 |
| H2SO4 Alkylation | -470 | 0 | 0 | 0 | 0 | -470 |
| Dimersol | 0 | 0 | 0 | 0 | 0 | 0 |
| Cat Poly | 8 | 0 | 0 | 0 | 0 | 8 |
| Isooctane | 0 | 0 | 0 | 0 | 0 | 0 |
| DHT - Total | -390 | 0 | -82 | -174 | 0 | -646 |
| DHT 2nd RCT - Total | -355 | -361 | -64 | -43 | 0 | -822 |
| DHT Arom Saturation | 0 | 0 | 0 | 0 | 0 | 0 |
| NHT - Total Fd | 0 | 0 | 0 | 31 | 0 | 31 |
| CGH - Generic | 109 | -157 | -59 | 4 | 0 | -102 |
| CGH - Olefin Sat'n | 0 | 0 | 0 | 0 | 0 | 0 |
| FCCU Fd HDT | 319 | 0 | 0 | 0 | 0 | 319 |
| LSR Splitter | 0 | -17 | 0 | 0 | 0 | -17 |
| LSR Bz Saturator | 0 | 0 | 0 | 0 | 0 | 0 |
| Reformate Saturator | -110 | 0 | -9 | 0 | 0 | -119 |
| Reformate Splitter | -64 | 0 | -4 | 0 | 0 | -68 |
| SDA | 0 | 0 | 0 | 0 | 0 | 0 |
| MTBE | 0 | 0 | 0 | 0 | 0 | 0 |
| TAME | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydrogen Plant - Total MSCF | -7 | -148 | -186 | -129 | 0 | -469 |
| Lube Unit | 0 | 0 | 0 | 0 | 0 | 0 |
| Sulfur Plant | 0 | 0 | 0 | 0 | 0 | -1 |
| Merox Jet | 0 | 0 | 0 | 0 | 0 | 0 |
| Merox Diesel | 0 | 0 | 0 | 0 | 0 | 0 |
| BTX Reformer - Tower feed | 0 | 1 | 0 | 0 | 0 | 1 |
| BTX Reformer - Extract feed | 0 | 0 | 0 | 0 | 0 | 0 |
| Total | -597 | -2,422 | -587 | -391 | 124 | -3,874 |

## Table 4.4-51.
## Projected Total U.S. Capital Investments for the High Ethanol Control Case Relative to the AEO 2007 Reference Case (billion dollars)

| Cost Type | Plant Type | Capital Investments |
|---|---|---|
| Production Costs | Corn Ethanol | 3.9 |
| | Cellulosic Ethanol | 48.3 |
| | Cellulosic Diesel [a] | 0 |
| | Renewable Diesel and Algae | 1.1 |
| Distribution Costs | All Ethanol | 11.9 |
| | Cellulosic and Renewable Diesel Fuel | - |
| | Biodiesel | 1.2 |
| | FFV Costs | 6.1 |
| | Refining | -4.1 |
| Total Capital Investments | | 68.4 |

## Table 4.4-52.
## Ethanol and Gasoline Volume, Quality and Energy Density by Gasoline Type at the PADD Terminal for the High Ethanol Control Case Relative to the AEO 2007 Reference Case

| | PADD 1 | | PADD 2 | | PADD 3 | | PADD 4/5 ex CA | | CA | | US | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Ref Case | Control | Ref Case | Control | Ref Case | Control | Ref Case | Control | Ref Case | Control | Ref Case | Control |
| RFG | | | | | | | | | | | | |
| Total ('000 BPD) | 1,376,331 | 834,232 | 319,080 | 216,604 | 459,343 | 324,886 | 0 | 0 | 1,299,365 | 1,305,768 | 3,454,120 | 2,681,490 |
| Ethanol ('000 BPD) | 139,023 | 84,266 | 32,230 | 21,879 | 46,397 | 32,817 | 0 | 0 | 131,244 | 131,896 | 348,895 | 270,858 |
| RVP (psi) | 10.8 | 10.3 | 10.6 | 12.5 | 9.7 | 11.3 | 0.0 | 0.0 | 9.5 | 9.4 | 10.1 | 10.1 |
| Sulfur (ppm) | 24.4 | 23.4 | 20.0 | 24.5 | 23.2 | 22.4 | 0.0 | 0.0 | 8.8 | 8.9 | 18.0 | 16.3 |
| Density | 258.9 | 259.4 | 258.2 | 257.1 | 259.5 | 258.7 | 0.0 | 0.0 | 258.5 | 258.9 | 258.8 | 258.9 |
| Octane (R+M/2) | 88.1 | 88.6 | 88.0 | 88.5 | 88.0 | 88.5 | 0.0 | 0.0 | 87.6 | 87.7 | 87.9 | 88.1 |
| Aromatics (vol%) | 19.9 | 20.0 | 19.9 | 20.0 | 19.6 | 19.8 | 0.0 | 0.0 | 22.2 | 22.2 | 20.7 | 21.1 |
| Benzene (vol%) | 0.57 | 0.58 | 0.57 | 0.57 | 0.56 | 0.54 | 0.00 | 0.00 | 0.53 | 0.55 | 0.55 | 0.56 |
| Olefins (vol%) | 13.6 | 14.0 | 9.4 | 11.4 | 11.5 | 13.7 | 0.0 | 0.0 | 5.7 | 5.7 | 10.0 | 9.7 |
| Oxygen (wt%) | 3.7 | 3.7 | 3.7 | 3.8 | 3.7 | 3.7 | 0.0 | 0.0 | 3.7 | 3.7 | 3.7 | 3.7 |
| E200 (vol%) | 55.6 | 56.7 | 58.3 | 60.7 | 53.3 | 54.2 | 0.0 | 0.0 | 58.2 | 58.2 | 56.5 | 57.4 |
| E300 (vol%) | 93.9 | 95.1 | 93.9 | 95.1 | 93.9 | 95.1 | 0.0 | 0.0 | 86.2 | 86.2 | 91.0 | 90.7 |
| Energy (MMBtu/Bbl) | 4.947 | 4.956 | 4.924 | 4.895 | 4.981 | 4.951 | 0.000 | 0.000 | 4.994 | 4.997 | 4.967 | 4.970 |
| CG | | | | | | | | | | | | |
| Total ('000 BPD) | 1,830,582 | 1,841,867 | 1,640,138 | 1,447,215 | 1,280,314 | 1,086,759 | 696,861 | 659,598 | 112,988 | 118,302 | 5,560,884 | 5,153,740 |
| Ethanol ('000 BPD) | 134,064 | 186,047 | 165,671 | 146,183 | 129,320 | 109,774 | 70,390 | 66,626 | 11,413 | 11,950 | 510,857 | 520,580 |
| RVP (psi) | 11.4 | 11.7 | 11.6 | 11.4 | 10.7 | 10.4 | 11.4 | 11.2 | 10.6 | 10.6 | 11.3 | 11.3 |
| Sulfur (ppm) | 22.9 | 24.1 | 23.6 | 24.7 | 23.1 | 22.6 | 28.0 | 28.0 | 26.6 | 25.6 | 23.9 | 24.5 |
| Density | 258.9 | 260.0 | 259.1 | 259.3 | 260.5 | 260.8 | 258.1 | 259.1 | 262.7 | 262.5 | 259.3 | 259.9 |
| Octane (R+M/2) | 87.8 | 88.0 | 88.0 | 88.1 | 88.0 | 88.2 | 86.9 | 87.0 | 89.3 | 89.2 | 87.8 | 88.0 |
| Aromatics (vol%) | 23.1 | 22.5 | 22.5 | 22.5 | 22.4 | 22.4 | 15.9 | 17.7 | 26.5 | 26.7 | 21.9 | 22.0 |
| Benzene (vol%) | 0.53 | 0.53 | 0.53 | 0.53 | 0.51 | 0.51 | 1.05 | 1.03 | 0.59 | 0.57 | 0.59 | 0.59 |
| Olefins (vol%) | 13.2 | 13.9 | 11.0 | 10.9 | 13.1 | 12.6 | 8.5 | 9.5 | 17.8 | 16.1 | 12.0 | 12.3 |
| Oxygen (wt%) | 2.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.7 | 3.4 | 3.7 |
| E200 (vol%) | 52.5 | 53.5 | 58.8 | 58.9 | 53.0 | 51.4 | 63.0 | 63.5 | 58.0 | 58.5 | 55.9 | 56.0 |
| E300 (vol%) | 93.9 | 80.4 | 93.9 | 95.0 | 93.9 | 79.2 | 93.9 | 95.8 | 86.2 | 86.2 | 93.7 | 86.3 |
| Energy (MMBtu/Bbl) | 4.995 | 4.974 | 4.925 | 4.938 | 4.988 | 4.998 | 0.000 | 4.930 | 4.942 | 4.929 | 4.961 | 4.962 |
| E85 | | | | | | | | | | | | |
| Total ('000 BPD) | 0 | 669,821 | 0 | 387,549 | 0 | 421,660 | 0 | 70,039 | 0 | 54,710 | 0 | 1,603,779 |
| Ethanol ('000 BPD) | 0 | 575,048 | 0 | 332,715 | 0 | 361,999 | 0 | 60,129 | 0 | 46,969 | 0 | 1,376,860 |
| RVP (psi) | 0.0 | 9.9 | 0.0 | 10.3 | 0.0 | 10.7 | 0.0 | 11.9 | 0.0 | 12.0 | 0.0 | 10.4 |
| Sulfur (ppm) | 0.0 | 10.1 | 0.0 | 9.7 | 0.0 | 9.6 | 0.0 | 9.0 | 0.0 | 8.8 | 0.0 | 9.8 |
| Density | 0.0 | 268.9 | 0.0 | 268.1 | 0.0 | 267.8 | 0.0 | 266.6 | 0.0 | 266.2 | 0.0 | 268.2 |
| Octane (R+M/2) | 0.0 | 107.7 | 0.0 | 107.7 | 0.0 | 107.8 | 0.0 | 107.9 | 0.0 | 107.9 | 0.0 | 107.7 |
| Aromatics (vol%) | 0.0 | 1.2 | 0.0 | 0.8 | 0.0 | 0.7 | 0.0 | 0.1 | 0.0 | 0.0 | 0.0 | 0.9 |
| Benzene (vol%) | 0.00 | 0.03 | 0.00 | 0.02 | 0.00 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 |
| Olefins (vol%) | 0.0 | 2.4 | 0.0 | 2.0 | 0.0 | 2.1 | 0.0 | 2.8 | 0.0 | 1.2 | 0.0 | 2.2 |
| Oxygen (wt%) | 0.0 | 30.5 | 0.0 | 25.7 | 0.0 | 30.6 | 0.0 | 28.6 | 0.0 | 30.8 | 0.0 | 29.3 |
| E200 (vol%) | 0.0 | 126.8 | 0.0 | 127.7 | 0.0 | 128.0 | 0.0 | 129.8 | 0.0 | 129.6 | 0.0 | 127.6 |
| E300 (vol%) | 0.0 | 95.6 | 0.0 | 95.9 | 0.0 | 96.0 | 0.0 | 96.6 | 0.0 | 96.6 | 0.0 | 95.8 |
| Energy (MMBtu/Bbl) | 0.000 | 3.656 | 0.000 | 3.642 | 0.000 | 3.633 | 0.000 | 3.605 | 0.000 | 3.596 | 0.000 | 3.642 |
| All Mogas | | | | | | | | | | | | |
| Total BPD | 3,206,913 | 3,345,919 | 1,959,219 | 2,051,367 | 1,739,657 | 1,833,305 | 696,861 | 729,637 | 1,412,353 | 1,478,780 | 9,015,003 | 9,439,008 |
| Ethanol BPD | 273,087 | 845,361 | 197,901 | 500,777 | 175,717 | 504,590 | 70,390 | 126,755 | 142,657 | 190,815 | 859,752 | 2,168,297 |
| RVP | 11.1 | 11.0 | 11.4 | 11.3 | 10.4 | 10.6 | 11.4 | 11.3 | 9.6 | 9.6 | 10.8 | 10.8 |
| Sulfur ppm | 24 | 21 | 23 | 22 | 23 | 19 | 28 | 26 | 10 | 10 | 22 | 20 |
| Density | 259 | 262 | 259 | 261 | 260 | 262 | 258 | 260 | 259 | 259 | 259 | 261 |
| R+M/2 | 87.9 | 92.1 | 88.0 | 91.9 | 88.0 | 92.7 | 86.9 | 89.0 | 87.8 | 88.5 | 87.8 | 91.4 |
| Aromatics | 21.7 | 17.6 | 22.1 | 18.1 | 21.7 | 16.9 | 15.9 | 16.0 | 22.5 | 21.8 | 21.5 | 18.1 |
| Benzene | 0.55 | 0.44 | 0.53 | 0.44 | 0.53 | 0.40 | 1.05 | 0.93 | 0.54 | 0.53 | 0.58 | 0.49 |
| Olefins | 13.4 | 11.6 | 10.7 | 9.3 | 12.7 | 10.3 | 8.5 | 8.9 | 6.7 | 6.4 | 11.2 | 9.8 |
| Oxygen (wt%) | 3.1 | 9.2 | 3.7 | 8.0 | 3.7 | 10.0 | 3.7 | 6.2 | 3.7 | 4.7 | 3.5 | 8.2 |
| E200 | 53.8 | 69.0 | 58.7 | 72.1 | 53.1 | 69.5 | 63.0 | 69.9 | 58.2 | 60.9 | 56.1 | 68.6 |
| E300 | 93.9 | 87.1 | 93.9 | 95.1 | 93.9 | 85.9 | 93.9 | 95.9 | 86.2 | 86.6 | 92.7 | 89.2 |
| Energy (MMBtu/Bbl) | 4.974 | 4.706 | 4.925 | 4.689 | 4.986 | 4.676 | 4.913 | 4.803 | 4.990 | 4.939 | 4.963 | 4.740 |

### 4.4.2.3.2 High Ethanol Control Case Relative to the RFS 1 Reference Case

This subsection summarizes the gasoline and diesel fuel costs and other impacts of the high ethanol control case relative to the RFS1 reference case.

## Table 4.4-53.
## High Ethanol Control Case Costs without Tax Subsidies Relative to the RFS 1 Reference Case

(2007 dollars, 7% ROI before taxes)

| | Gasoline | Diesel Fuel |
|---|---|---|
| Refinery Model Variable Operating Cost $MM/yr | 23,894 | - |
| Amortized Refinery Capital Costs $MM/yr | -460 | - |
| Fixed Operating Costs $MM/yr | -127 | - |
| Added Gasoline Transportation Cost $MM/yr | -257 | - |
| Removal of E85 Pricing Effect $MM/yr | -19,854 | - |
| Crude Oil Cost $51 to $116/bbl $MM/yr | -45,548 | - |
| Lower Energy Density $MM/yr | 29,609 | 502 |
| Adjustment from Ethanol Price to Cost $MM/yr | -1,524 | - |
| FFV Costs $MM/yr | 6,476 | |
| Renewable Diesel Cost vs Petroleum Diesel $MM/yr | - | -1,851 |
| Total Costs $MM/yr | -7,790 | -1,350 |
| Refinery Model Variable Operating Cost c/gal | 16.51 | - |
| Amortized Refinery Capital Costs c/gal | -0.32 | - |
| Fixed Operating Costs c/gal | -0.09 | - |
| Added Gasoline Transportation Cost c/gal | -0.18 | - |
| Removal of E85 Pricing Effect c/gal | -13.72 | - |
| Crude Oil Cost $51 to $116/bbl c/gal | -31.48 | - |
| Lower Energy Density c/gal | 20.46 | 0.71 |
| Adjustment from Ethanol Price to Cost c/gal | -1.05 | - |
| FFV Costs c/gal | 4.48 | |
| Renewable Diesel Cost vs Petroleum Diesel c/gal | - | -2.61 |
| Total Costs c/gal | -5.38 | -1.90 |

## Table 4.4-54.
## High Ethanol Control Case Costs Reflecting Tax Subsidies Relative to the RFS 1 Control Case

(2007 dollars, 7% ROI before taxes)

| | Gasoline | Diesel Fuel |
|---|---|---|
| Total Costs $MM/yr | -7,790 | -1,350 |
| Federal Subsidies $MM/yr | -20,266 | -1,441 |
| Revised Total Cost $MM/yr | -28,055 | -2,791 |
| Total Costs c/gal | -5.38 | -1.90 |
| Federal Subsidies c/gal | -14.01 | -2.03 |
| Total Costs c/gal | -19.39 | -3.94 |

# Table 4.4-55.
# Summary of the Total and Incremental Volumetric Refinery Inputs by PADD for the High Ethanol Control Case Relative to the RFS 1 Reference Case (barrels/day)

| | PADD 1 | | PADD 2 | | PADD 3 | | PADD 4/5 ex CA | | CA | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case |
| PADD Crude | 1,347,342 | -151,714 | 3,058,241 | -475,740 | 7,117,305 | -241,263 | 1,534,859 | -4,119 | 1,886,357 | -1,136 |
| GTL Naphtha | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| GTL Diesel | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| VGO HS | 0 | 0 | 0 | 0 | 0 | -33,772 | 0 | 0 | 0 | 0 |
| VGO LS | 0 | 0 | 7,920 | -23,914 | 0 | 0 | 0 | 0 | 0 | 0 |
| HS AR (A960) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LS AR (Alg) | 279,819 | 39,889 | 0 | 0 | 738,057 | 21,829 | 0 | 0 | 0 | 0 |
| Normal Butane | 30,814 | 8,329 | 78,293 | 19,185 | 69,363 | -14,040 | 25,526 | -13,917 | 39,573 | 0 |
| Isobutane | 12,582 | 12,582 | 16,476 | -8,390 | 8,234 | 8,234 | 1,178 | -22,245 | 0 | 0 |
| Other | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| MTBE | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Ethanol - E10 | 270,313 | 130,437 | 168,062 | 63,684 | 142,590 | 88,811 | 66,626 | 40,273 | 143,845 | 8,610 |
| Ethanol - E20 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Ethanol - E85 | 575,048 | 575,048 | 332,715 | 332,715 | 361,999 | 361,999 | 60,129 | 60,129 | 46,969 | 46,969 |
| Reformer Feed | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Methanol | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Natural Gas (FOE) | 74,115 | -6,201 | 136,509 | -5,559 | 493,553 | 6,876 | 86,015 | -3,625 | 154,032 | -2,444 |
| Hydrogen (MSCF) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Pentanes Plus | 0 | 0 | 58 | -32,066 | 52,055 | 0 | 0 | -17,467 | 0 | 0 |
| Import CBOB 10% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Import CBOB 20% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Import RBOB 10% | 0 | -200,000 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Import RBOB 20% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Import Alkylate | 45,167 | 45,167 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Import Raffinate | 3,442 | -61,147 | 0 | 0 | 0 | 0 | 0 | 0 | 45,808 | 0 |
| Import Reformate | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Import FCC Naphtha | 15,980 | 15,980 | 0 | 0 | 11,943 | 11,943 | 18,580 | 18,580 | 0 | 0 |
| Import Lt Naphtha | 0 | 0 | 17,575 | 17,575 | 0 | 0 | 0 | 0 | 584 | 0 |
| Import Hvy Naph | 0 | 0 | 0 | 0 | 41,644 | 0 | 0 | 0 | 0 | 0 |
| Transfer Lt Naphtha | 0 | -23,342 | 0 | -20,822 | 0 | 0 | 0 | 0 | 11,387 | -9,842 |
| Transfer Reformate | 16,658 | 0 | 0 | -14,074 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfer Alkylate | 60,000 | 17,381 | 0 | 0 | 0 | 0 | 0 | 0 | 60,000 | 16,933 |
| Transfer FCC Naphtha | 0 | 0 | 20,822 | 20,822 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfer Raffinate | 0 | 0 | 11,353 | -5,888 | 0 | 0 | 0 | 0 | 60,000 | 11,077 |
| Transfer RBOB 10% | 242,605 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfer RBOB 20% | 0 | 0 | 8,720 | 8,720 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfer CBOB 10% | 1,398,409 | 1,381,833 | 80,262 | 77,306 | 0 | 0 | 6,493 | -19,539 | 0 | 0 |
| Transfer CBOB 20% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Isooctane | 100 | 0 | 100 | 0 | 100 | 0 | 100 | 0 | 16,462 | 2,029 |
| Isooctene | 100 | 0 | 100 | 0 | 100 | 0 | 100 | 0 | 600 | 0 |

# Table 4.4-56.
# Summary of Total and Incremental Refinery Outputs by PADD for the High Ethanol Control Case Relative to the RFS 1 Reference Case
# (barrels/day)

| | PADD 1 | | PADD 2 | | PADD 3 | | PADD 4/5 ex CA | | CA | |
|---|---|---|---|---|---|---|---|---|---|---|
| | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case | Control Case | Difference from Ref Case |
| Propane | 34,143 | 1,539 | 50,843 | -12,263 | 103,144 | -32,064 | 23,369 | -1,541 | 52,782 | 1,461 |
| Propylene | 18,685 | 0 | 42,525 | 0 | 245,407 | 0 | 2,041 | 0 | 11,774 | 0 |
| Normal Butane | 0 | -7,832 | 0 | -2,370 | 0 | -45,506 | 0 | 0 | 0 | 0 |
| Isobutane | 0 | 0 | 0 | 0 | 0 | -345 | 0 | 0 | 40,012 | 5,009 |
| PC Naphtha | 15,830 | 0 | 40,290 | 0 | 432,937 | 0 | 0 | 0 | 0 | 0 |
| PC Gasoil | 0 | 0 | 455,618 | -108,658 | 157,500 | 0 | 0 | 0 | 0 | 0 |
| CG Reg | 0 | -118,066 | 0 | -852,131 | 0 | -2,020,447 | 0 | -374,129 | 0 | -53,481 |
| CG Prem | 0 | 0 | 0 | 0 | 0 | -416,926 | 0 | -51,984 | 0 | 0 |
| CG E10 Reg | 1,535,198 | 1,516,962 | 1,172,450 | 704,964 | 872,274 | 872,274 | 542,856 | 325,693 | 99,374 | 59,284 |
| CG E10 Prem | 306,669 | 306,669 | 274,765 | 23,409 | 214,485 | 134,887 | 116,742 | 72,990 | 18,928 | 1,105 |
| RFG E10 Reg | 605,554 | -542,443 | 163,150 | -101,096 | 246,042 | -134,362 | 0 | 0 | 1,088,091 | 12,026 |
| RFG E10 Prem | 228,678 | 10,012 | 53,454 | 3,122 | 78,844 | 6,386 | 0 | 0 | 217,676 | 12,712 |
| CG E20 Reg | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| RFG E20 Reg | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| E85 to CG | 74,814 | 74,814 | 270,064 | 270,064 | 253,773 | 253,773 | 70,039 | 70,039 | 0 | 0 |
| E85 to RFG | 595,006 | 595,006 | 117,484 | 117,484 | 167,888 | 167,888 | 0 | 0 | 54,710 | 54,710 |
| Transfer RBOB 10% | 0 | 0 | 0 | 0 | 251,325 | 8,720 | 0 | 0 | 0 | 0 |
| Transfer RBOB 20% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfer CBOB 10% | 0 | 0 | 0 | 0 | 1,485,164 | 1,439,600 | 0 | 0 | 0 | 0 |
| Transfer CBOB 20% | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Jet/Kero A (450ppm) | 70,000 | 0 | 138,523 | -3,108 | 936,227 | 0 | 274,537 | 0 | 229,653 | 0 |
| X-Fer Diesel Rundown t | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| HSD Gr 76 (0.2%) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| LSD Gr 74 (.05%) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| ULSD (15 ppm) | 587,042 | -39,165 | 643,331 | -30,227 | 2,150,901 | 2,423 | 523,035 | -11,120 | 0 | 0 |
| CARB Diesel | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 358,152 | -6,714 |
| X-Fer C5's to Storage | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 1% Residual Fuel | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Residual Fuel | 68,283 | -21,481 | 67,826 | 8 | 262,834 | 0 | 138,312 | 22,862 | 45,680 | -4,199 |
| Slurry | 30,026 | 3,876 | 67,363 | -19,645 | 112,554 | -4,041 | 12,295 | -4,210 | 29,893 | 1,191 |
| Asphalt & Wax | 86,013 | -5,669 | 198,329 | -11,671 | 157,500 | 0 | 5,250 | 0 | 41,774 | 0 |
| Gasoil | 0 | 0 | 4,895 | 0 | 0 | 0 | 0 | 0 | 9,814 | 0 |
| Lubes | 18,706 | 0 | 17,313 | 0 | 157,500 | 0 | 0 | 0 | 20,149 | 0 |
| Benzene | 11,003 | 0 | 11,003 | 0 | 51,347 | 0 | 0 | 0 | 0 | 0 |
| Toluene | 0 | 0 | 0 | 0 | 34,910 | 0 | 0 | 0 | 0 | 0 |
| Xylenes | 0 | 0 | 0 | 0 | 7,777 | 0 | 0 | 0 | 0 | 0 |
| Cumene | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Other | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Cyclohexane | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Transfer Raffinate | 0 | 0 | 0 | 0 | 71,353 | 5,190 | 0 | 0 | 0 | 0 |
| Transfer Alkylate | 0 | 0 | 0 | 0 | 120,000 | 34,314 | 0 | 0 | 0 | 0 |
| Transfer Reformate | 0 | 0 | 0 | 0 | 16,658 | 16,658 | 0 | 0 | 0 | 0 |
| Transfer FCC naphtha | 0 | 0 | 0 | 0 | 20,822 | 20,822 | 0 | 0 | 0 | 0 |
| Transfer Lt Naphtha | 0 | 0 | 0 | 0 | 0 | -23,342 | 0 | 0 | 11,387 | -9,842 |
| Transfer Blendstock | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| Sulfur (STons) | 1,076 | -74 | 3,571 | -630 | 12,042 | -533 | 2,038 | -59 | 3,559 | -10 |
| Coke (STon) | 3,495 | -227 | 10,154 | -3,068 | 48,646 | -2,278 | 7,899 | -790 | 17,358 | 86 |

## Table 4.4-57.
## Change in Refinery Unit Capacities by PADD for the High Ethanol Control Case Relative to the RFS 1 Reference Case
## (thousand barrels/day)

| | PADD 1 | PADD 2 | PADD 3 | PADD 4/5 ex CA | California | US Total |
|---|---|---|---|---|---|---|
| Crude Tower | 0 | -439 | 0 | 0 | 0 | -439 |
| Vacuum Tower | 0 | -196 | 0 | -2 | 0 | -198 |
| Sats Gas Plant | 3 | 0 | -30 | 0 | 9 | -18 |
| Unsats Gas Plant | -2 | 0 | 0 | 0 | 0 | -2 |
| FCC DeC5 Tower | 0 | 0 | 0 | 0 | 0 | 0 |
| FCC | 0 | 0 | 0 | -8 | 0 | -8 |
| FCC Splitter | 2 | -6 | 0 | 0 | 0 | -5 |
| Hydrocracker | -18 | 0 | 0 | -14 | 0 | -33 |
| H-Oil Unit | 0 | 0 | 0 | 0 | 0 | 0 |
| Delayed Coker | 0 | 0 | 0 | -28 | 0 | -28 |
| Visbreaker | 0 | 0 | 0 | 0 | 0 | 0 |
| Thermal Naphtha Splitter | -1 | -6 | 0 | -1 | 0 | -8 |
| CRU Reformer | 0 | 0 | 0 | 0 | 0 | 0 |
| SRU Reformer | 0 | 0 | 0 | 0 | -1 | -1 |
| BTX Reformer | 0 | -10 | -18 | 0 | 0 | -27 |
| C4 Isomerization | 0 | 0 | 0 | 0 | 1 | 1 |
| C5/C6 Isomerization | 26 | 0 | 0 | 0 | 0 | 26 |
| HF Alkylation | 0 | 0 | 0 | 0 | 0 | 0 |
| H2SO4 Alkylation | 1 | 0 | 0 | -5 | 0 | -4 |
| Dimersol | 0 | 0 | 0 | 0 | 0 | 0 |
| Cat Poly | 0 | 0 | 0 | 0 | 0 | 0 |
| Isooctane | 0 | 0 | 0 | 0 | 0 | 0 |
| DHT - Total | -132 | 0 | -103 | -50 | -4 | -290 |
| DHT 2nd RCT - Total | -117 | -153 | -174 | -52 | -4 | -501 |
| DHT Arom Saturation | 0 | 0 | 0 | 0 | 0 | 0 |
| NHT - Total Fd | 0 | 0 | 0 | -4 | 0 | -4 |
| CGH - Generic | -12 | -19 | -19 | -6 | 0 | -57 |
| CGH - Olefin Sat'n | 0 | 0 | 0 | 0 | 0 | 0 |
| FCCU Fd HDT | 37 | 0 | 0 | 0 | 0 | 37 |
| LSR Splitter | 0 | 41 | 38 | 0 | 0 | 80 |
| LSR Bz Saturator | 0 | 0 | 0 | 0 | 0 | 0 |
| Reformate Saturator | -4 | -4 | 1 | 0 | 0 | -7 |
| Reformate Splitter | -12 | -12 | 3 | 0 | 0 | -21 |
| SDA | 0 | 0 | 0 | 0 | 0 | 0 |
| MTBE | 0 | 0 | 0 | 0 | 0 | 0 |
| TAME | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydrogen Plant - Total MSC | -72 | 11 | 109 | -47 | 0 | 1 |
| Lube Unit | 0 | 0 | 0 | 0 | 0 | 0 |
| Sulfur Plant | -128 | 0 | 0 | -204 | -71 | -402 |
| Merox Jet | 0 | 0 | 0 | 0 | 0 | 0 |
| Merox Diesel | 0 | 0 | 0 | 0 | 0 | 0 |
| BTX Reformer - Tower feed | 0 | -1 | -1 | 0 | 0 | -2 |
| BTX Reformer - Extract fee | -1 | 0 | 0 | 0 | 0 | -1 |

## Table 4.4-58.
## Change in Refinery Unit Investments by PADD for the High Ethanol Control Case Relative to the RFS 1 Reference Case (million dollars/year)

| | PADD 1 | PADD 2 | PADD 3 | PADD 4/5 ex CA | California | US Total |
|---|---|---|---|---|---|---|
| Crude Tower | 0 | -997 | 0 | 0 | 0 | -997 |
| Vacuum Tower | 0 | -591 | 0 | 0 | 0 | -591 |
| Sats Gas Plant | 12 | 0 | -101 | 0 | 55 | -34 |
| Unsats Gas Plant | -10 | 0 | 0 | 0 | 0 | -10 |
| FCC DeC5 Tower | 0 | 0 | 0 | 0 | 0 | 0 |
| FCC | 0 | 0 | 0 | -193 | 0 | -193 |
| FCC Splitter | 1 | -7 | 0 | 0 | 0 | -6 |
| Hydrocracker | -631 | 0 | 0 | -505 | 0 | -1,137 |
| H-Oil Unit | 0 | 0 | 0 | 0 | 0 | 0 |
| Delayed Coker | 0 | 0 | 0 | -592 | 0 | -592 |
| Visbreaker | 0 | 0 | 0 | 0 | 0 | 0 |
| Thermal Naphtha Splitter | -3 | -7 | 0 | -3 | 0 | -13 |
| CRU Reformer | 0 | 0 | 0 | 0 | 0 | 0 |
| SRU Reformer | 0 | 0 | 0 | 0 | -4 | -4 |
| BTX Reformer | 0 | -93 | -231 | 0 | 0 | -324 |
| C4 Isomerization | 0 | 0 | 0 | 0 | 8 | 8 |
| C5/C6 Isomerization | 227 | 0 | 0 | 0 | 0 | 227 |
| HF Alkylation | 0 | 0 | 0 | 0 | 0 | 0 |
| H2SO4 Alkylation | 16 | 0 | 0 | -70 | 0 | -54 |
| Dimersol | 0 | 0 | 0 | 0 | 0 | 0 |
| Cat Poly | -1 | 0 | 0 | 0 | 0 | -1 |
| Isooctane | 0 | 0 | 0 | 0 | 0 | 0 |
| DHT - Total | -1,367 | 0 | -702 | -539 | -96 | -2,703 |
| DHT 2nd RCT - Total | -904 | -998 | -840 | -312 | -21 | -3,076 |
| DHT Arom Saturation | 0 | 0 | 0 | 0 | 0 | 0 |
| NHT - Total Fd | 0 | 0 | 0 | -46 | 0 | -46 |
| CGH - Generic | -58 | -63 | -92 | -25 | 0 | -238 |
| CGH - Olefin Sat'n | 0 | 0 | 0 | 0 | 0 | 0 |
| FCCU Fd HDT | 555 | 0 | 0 | 0 | 0 | 555 |
| LSR Splitter | 0 | 29 | 18 | 0 | 0 | 47 |
| LSR Bz Saturator | 0 | 0 | 0 | 0 | 0 | 0 |
| Reformate Saturator | -46 | -19 | 4 | 0 | 0 | -60 |
| Reformate Splitter | -20 | -16 | 2 | 0 | 0 | -34 |
| SDA | 0 | 0 | 0 | 0 | 0 | 0 |
| MTBE | 0 | 0 | 0 | 0 | 0 | 0 |
| TAME | 0 | 0 | 0 | 0 | 0 | 0 |
| Hydrogen Plant - Total MSC | -255 | 69 | 274 | -171 | 0 | -84 |
| Lube Unit | 0 | 0 | 0 | 0 | 0 | 0 |
| Sulfur Plant | -3 | 0 | 0 | -2 | -2 | -7 |
| Merox Jet | 0 | 0 | 0 | 0 | 0 | 0 |
| Merox Diesel | 0 | 0 | 0 | 0 | 0 | 0 |
| BTX Reformer - Tower feed | 0 | -2 | -1 | 0 | 0 | -3 |
| BTX Reformer - Extract feed | -3 | 0 | 0 | 0 | 0 | -3 |
| Total | -2,491 | -2,694 | -1,669 | -2,459 | -59 | -9,373 |

# Table 4.4-59.
# Ethanol and Gasoline Volume, Quality and Energy Density by Gasoline Type at the PADD Terminal for the High Ethanol Control Case Relative to the RFS 1 Reference Case

| | PADD 1 | | PADD 2 | | PADD 3 | | PADD 4/5 ex CA | | CA | | US | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Ref Case | Control | Ref Case | Control | Ref Case | Control | Ref Case | Control | Ref Case | Control | Ref Case | Control |
| RFG | | | | | | | | | | | | |
| Total ('000 BPD) | 1,366,663 | 834,232 | 314,578 | 216,604 | 452,862 | 324,886 | 0 | 0 | 1,281,031 | 1,305,768 | 3,415,134 | 2,681,490 |
| Ethanol ('000 BPD) | 138,034 | 84,266 | 31,773 | 21,879 | 45,739 | 32,817 | 0 | 0 | 129,386 | 131,896 | 344,932 | 270,858 |
| RVP (psi) | 10.7 | 10.3 | 10.3 | 12.5 | 9.6 | 11.3 | 0.0 | 0.0 | 9.5 | 9.4 | 10.1 | 10.1 |
| Sulfur (ppm) | 23.8 | 23.4 | 20.1 | 24.5 | 23.5 | 22.4 | 0.0 | 0.0 | 8.7 | 8.9 | 17.8 | 16.3 |
| Density | 258.5 | 259.4 | 256.2 | 257.1 | 259.1 | 258.7 | 0.0 | 0.0 | 258.5 | 258.9 | 258.4 | 258.9 |
| Octane (R+M/2) | 88.1 | 88.6 | 88.0 | 88.5 | 88.0 | 88.5 | 0.0 | 0.0 | 87.6 | 87.7 | 87.9 | 88.1 |
| Aromatics (vol%) | 19.9 | 20.0 | 18.2 | 20.0 | 19.5 | 19.8 | 0.0 | 0.0 | 22.2 | 22.2 | 20.5 | 21.1 |
| Benzene (vol%) | 0.57 | 0.58 | 0.57 | 0.57 | 0.57 | 0.54 | 0.00 | 0.00 | 0.54 | 0.55 | 0.56 | 0.56 |
| Olefins (vol%) | 13.1 | 14.0 | 8.0 | 11.4 | 9.3 | 13.7 | 0.0 | 0.0 | 5.7 | 5.7 | 9.3 | 9.7 |
| Oxygen (wt%) | 3.7 | 3.7 | 3.8 | 3.8 | 3.7 | 3.7 | 0.0 | 0.0 | 3.7 | 3.7 | 3.7 | 3.7 |
| E200 (vol%) | 55.7 | 56.7 | 62.5 | 60.7 | 54.5 | 54.2 | 0.0 | 0.0 | 58.5 | 58.2 | 57.2 | 57.4 |
| E300 (vol%) | 93.9 | 95.1 | 91.5 | 95.1 | 93.9 | 95.1 | 0.0 | 0.0 | 86.2 | 86.2 | 90.8 | 90.7 |
| Energy (MMBtu/Bbl | 4.963 | 4.956 | 4.864 | 4.895 | 5.027 | 4.951 | 0.000 | 0.000 | 4.988 | 4.997 | 4.971 | 4.970 |
| CG | | | | | | | | | | | | |
| Total ('000 BPD) | 1,841,024 | 1,841,867 | 1,570,973 | 1,447,215 | 1,262,249 | 1,086,759 | 687,028 | 659,598 | 111,394 | 118,302 | 5,472,668 | 5,153,740 |
| Ethanol ('000 BPD) | 1,842 | 186,047 | 72,606 | 146,183 | 8,040 | 109,774 | 26,352 | 66,626 | 5,849 | 11,950 | 114,689 | 520,580 |
| RVP (psi) | 10.5 | 11.7 | 11.8 | 11.4 | 10.7 | 10.4 | 11.3 | 11.2 | 10.8 | 10.6 | 11.0 | 11.3 |
| Sulfur (ppm) | 27.8 | 24.1 | 25.3 | 24.7 | 27.3 | 22.6 | 24.6 | 28.0 | 26.4 | 25.6 | 26.6 | 24.5 |
| Density | 259.3 | 260.0 | 258.8 | 259.3 | 259.4 | 260.8 | 256.8 | 259.1 | 260.8 | 262.5 | 258.9 | 259.9 |
| Octane (R+M/2) | 88.0 | 88.0 | 88.0 | 88.1 | 88.0 | 88.2 | 86.8 | 87.0 | 88.0 | 89.2 | 87.8 | 88.0 |
| Aromatics (vol%) | 28.7 | 22.5 | 26.3 | 22.5 | 28.4 | 22.4 | 19.3 | 17.7 | 26.8 | 26.7 | 26.7 | 22.0 |
| Benzene (vol%) | 0.65 | 0.53 | 0.64 | 0.53 | 0.65 | 0.51 | 0.80 | 1.03 | 0.62 | 0.57 | 0.67 | 0.59 |
| Olefins (vol%) | 15.2 | 13.9 | 11.2 | 10.9 | 16.0 | 12.6 | 8.0 | 9.5 | 18.6 | 16.1 | 13.4 | 12.3 |
| Oxygen (wt%) | 0.0 | 3.7 | 1.7 | 3.7 | 0.2 | 3.7 | 1.4 | 3.7 | 1.9 | 3.7 | 0.8 | 3.7 |
| E200 (vol%) | 45.2 | 53.5 | 52.9 | 58.9 | 45.9 | 51.4 | 58.9 | 63.5 | 54.5 | 58.5 | 49.5 | 56.0 |
| E300 (vol%) | 93.9 | 80.4 | 91.5 | 95.0 | 93.9 | 79.2 | 93.9 | 95.8 | 86.2 | 86.2 | 93.0 | 86.3 |
| Energy (MMBtu/Bbl | 5.133 | 4.974 | 5.007 | 4.938 | 5.127 | 4.998 | 5.004 | 4.930 | 4.998 | 4.929 | 5.077 | 4.962 |
| E85 | | | | | | | | | | | | |
| Total ('000 BPD) | 0 | 669,821 | 0 | 387,549 | 0 | 421,660 | 0 | 70,039 | 0 | 54,710 | 0 | 1,603,779 |
| Ethanol ('000 BPD) | 0 | 575,048 | 0 | 332,715 | 0 | 361,999 | 0 | 60,129 | 0 | 46,969 | 0 | 1,376,860 |
| RVP (psi) | 0.0 | 9.9 | 0.0 | 10.3 | 0.0 | 10.7 | 0.0 | 11.9 | 0.0 | 12.0 | 0.0 | 10.4 |
| Sulfur (ppm) | 0.0 | 10.1 | 0.0 | 9.7 | 0.0 | 9.6 | 0.0 | 9.0 | 0.0 | 8.8 | 0.0 | 9.8 |
| Density | 0.0 | 268.9 | 0.0 | 268.1 | 0.0 | 267.8 | 0.0 | 266.6 | 0.0 | 266.2 | 0.0 | 268.2 |
| Octane (R+M/2) | 0.0 | 107.7 | 0.0 | 107.7 | 0.0 | 107.8 | 0.0 | 107.9 | 0.0 | 107.9 | 0.0 | 107.7 |
| Aromatics (vol%) | 0.0 | 1.2 | 0.0 | 0.8 | 0.0 | 0.7 | 0.0 | 0.1 | 0.0 | 0.0 | 0.0 | 0.9 |
| Benzene (vol%) | 0.00 | 0.03 | 0.00 | 0.02 | 0.00 | 0.02 | 0.00 | 0.00 | 0.00 | 0.00 | 0.00 | 0.03 |
| Olefins (vol%) | 0.0 | 2.4 | 0.0 | 2.0 | 0.0 | 2.1 | 0.0 | 2.8 | 0.0 | 1.2 | 0.0 | 2.2 |
| Oxygen (wt%) | 0.0 | 30.5 | 0.0 | 25.7 | 0.0 | 30.6 | 0.0 | 28.6 | 0.0 | 30.8 | 0.0 | 29.3 |
| E200 (vol%) | 0.0 | 126.8 | 0.0 | 127.7 | 0.0 | 128.0 | 0.0 | 129.8 | 0.0 | 129.6 | 0.0 | 127.6 |
| E300 (vol%) | 0.0 | 95.6 | 0.0 | 95.9 | 0.0 | 96.0 | 0.0 | 96.6 | 0.0 | 96.6 | 0.0 | 95.8 |
| Energy (MMBtu/Bbl | 0.000 | 3.656 | 0.000 | 3.642 | 0.000 | 3.633 | 0.000 | 3.605 | 0.000 | 3.596 | 0.000 | 3.642 |
| All Mogas | | | | | | | | | | | | |
| Total BPD | 3,207,687 | 3,345,919 | 1,885,551 | 2,051,367 | 1,715,111 | 1,833,305 | 687,028 | 729,637 | 1,392,425 | 1,478,780 | 8,887,802 | 9,439,008 |
| Ethanol BPD | 139,876 | 845,361 | 104,378 | 500,777 | 53,780 | 504,590 | 26,352 | 126,755 | 135,236 | 190,815 | 459,622 | 2,168,297 |
| RVP | 10.6 | 11.0 | 11.5 | 11.3 | 10.4 | 10.6 | 11.3 | 11.3 | 9.6 | 9.6 | 10.6 | 10.8 |
| Sulfur ppm | 26.1 | 21.0 | 24.5 | 21.8 | 26.3 | 19.5 | 24.6 | 26.1 | 10.1 | 10.3 | 23.2 | 19.6 |
| Density | 258.9 | 261.7 | 258.4 | 260.8 | 259.3 | 262.1 | 256.8 | 259.8 | 258.7 | 259.4 | 258.7 | 261.1 |
| R+M/2 | 88.0 | 92.1 | 88.0 | 91.9 | 88.0 | 92.7 | 86.8 | 89.0 | 87.7 | 88.5 | 87.8 | 91.4 |
| Aromatics | 24.9 | 17.6 | 24.9 | 18.1 | 26.0 | 16.9 | 19.3 | 16.0 | 22.6 | 21.8 | 24.3 | 18.1 |
| Benzene | 0.62 | 0.44 | 0.63 | 0.44 | 0.63 | 0.40 | 0.80 | 0.93 | 0.55 | 0.53 | 0.63 | 0.49 |
| Olefins | 14.3 | 11.6 | 10.7 | 9.3 | 14.2 | 10.3 | 8.0 | 8.9 | 6.7 | 6.4 | 11.8 | 9.8 |
| Oxygen (wt%) | 1.6 | 9.2 | 2.0 | 8.0 | 1.2 | 10.0 | 1.4 | 6.2 | 3.6 | 4.7 | 1.9 | 8.2 |
| E200 | 49.7 | 69.0 | 54.5 | 72.1 | 48.1 | 69.5 | 58.9 | 69.9 | 58.1 | 60.9 | 52.5 | 68.6 |
| E300 | 93.9 | 87.1 | 91.5 | 95.1 | 93.9 | 85.9 | 93.9 | 95.9 | 86.2 | 86.6 | 92.2 | 89.2 |
| Energy (MMBtu/Bbl | 5.061 | 4.706 | 4.983 | 4.689 | 5.101 | 4.676 | 5.004 | 4.803 | 4.988 | 4.939 | 5.036 | 4.740 |

# Chapter 5: Economic Impacts and Benefits

## 5.1 Agricultural Impacts

### 5.1.1 Models Utilized

EPA used a suite of tools to model the potential domestic and international impacts of the RFS2 renewable fuel volumes on the agricultural sector. The Forest and Agricultural Sector Optimization Model (FASOM), developed by Professor Bruce McCarl of Texas A&M University and others, provides detailed information on domestic agricultural and greenhouse gas impacts of renewable fuels. The Food and Agricultural Policy Research Institute (FAPRI) at Iowa State University and the University of Missouri-Columbia maintains a number of econometric models that are capable of providing detailed information on impacts on international agricultural markets from the wider use of renewable fuels in the U.S. EPA worked directly with the Center for Agriculture and Rural Development (CARD) at Iowa State University to implement the FAPRI model to analyze the impacts of the RFS2 on the global agriculture sector. Thus, this model will henceforth be referred to as the FAPRI-CARD model.

FASOM is a long-term economic model of the U.S. forest and agricultural sectors that maximizes the net present value of the sum of producer and consumer surplus across the two sectors over time subject to market, technology, and other constraints. Using a number of inputs, the agricultural component of FASOM determines the equilibrium combination of crops, livestock, and processed agricultural products that would be produced in the U.S. for each model solution period. In each model simulation, crops and livestock compete for price sensitive inputs such as land and labor at the regional level. The cost of these and other inputs are used to determine the price and level of production of primary commodities (e.g., field crops, livestock, and biofuel products). FASOM also estimates prices using costs associated with the processing of primary commodities into secondary products (e.g., converting livestock to meat and dairy products, crushing soybeans to soybean meal and oil). FASOM does not capture short-term fluctuations (i.e., month-to-month, annual) in prices and production, however, as it is designed to identify long-term trends.

The FASOM model also contains a forestry component, which details forest acres across the U.S., as well as production of forestry products. Running the forestry and agriculture components of the model simultaneously shows the interaction between these two sectors as they compete for land, as well as the effect on products and prices in each respective sector. In total, FASOM includes a representation of seven major land use categories, including cropland, cropland pasture, forestland, forest pasture, rangeland, developed land, and acres enrolled in the Conservation Reserve Program (CRP). More information on these land categories can be found below in Chapter 5.1.2.

FASOM uses supply and demand curves for the 11 major U.S. domestic regions,[VVVVVVVVVV] which are calibrated to historic price and production data. FASOM also includes detailed supply and demand data for corn, wheat, soybeans, rice and sorghum across 37

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[VVVVVVVVVV] U.S. regions consist of the Pacific Northwest (West and East), Pacific Southwest, Rocky Mountains, Great Plains, Southwest, South Central, Corn Belt, Lake States, Southeast, and the Northeast.

foreign regions.[WWWWWWWWWW] FASOM contains transportation costs to all regions and then uses all of this information to solve for the level of U.S. exports where prices are then equated in all markets.

We chose to use FASOM to model the full potential impacts on the domestic agricultural and forestry sectors given higher renewable fuel volumes, in part because FASOM also provides detailed greenhouse gas information resulting from these changes (see Chapter 2 of this RIA for more information). FASOM does not model agricultural sector changes internationally, however. Therefore, we are working with the FAPRI-CARD modeling system to better understand international agricultural impacts. Additional details on the FASOM model are included in the docket.[XXXXXXXXXX]

The FAPRI-CARD models are a system of econometric models covering many agricultural commodities. These models capture the biological, technical, and economic relationships among key variables within a particular commodity and across commodities. They are based on historical data analysis, current academic research, and a reliance on accepted economic, agronomic, and biological relationships in agricultural production and markets. The international modeling system includes international grains, oilseeds complex, biofuel (ethanol and biodiesel), sugar, cotton, dairy, and livestock models. In general, for each commodity sector, the equilibrium economic relationship that supply equals demand is solved by determining a market-clearing price for the commodity. In countries where domestic prices are not solved endogenously, these prices are modeled as a function of the world price using a price transmission equation. Since econometric models for each sector are linked, changes in one commodity sector will impact other sectors. Elasticity values for supply and demand responses are based on econometric analysis and on consensus estimates. Additional details on the FAPRI-CARD models are included in the docket.[YYYYYYYYYY]

Agricultural and trade policies for each commodity in a country are included in the models to the extent that they affect the supply and demand decisions of the economic agents. These policies include taxes on exports and imports, tariffs, tariff rate quotas, export subsidies, intervention prices, and set-aside rates. The FAPRI-CARD models assume that existing agricultural and trade policy variables will remain unchanged in the outlook period.

We recognize that there are inherent challenges in reconciling the results from two different models, however using two models provides a more complete and robust analysis than either model would be able to provide alone. As described in Chapter 5.1.3, we have attempted to align as many of the key assumptions as possible to get a consistent set of modeling results. However, there are structural differences in the models that account for some of the differences

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[WWWWWWWWWW] FASOM Foreign Regions include: the European Economic Community, North Central Europe, Southwest Europe, Eastern Europe, Adriatic, Eastern Mediterranean, Former Soviet Union, North Africa, East Africa, West Africa, South Africa, Red Sea, Iran, India, Taiwan, Japan, South Korea, North Korea, China, Bangladesh, Indonesia, Myanmar, Pakistan, Philippines, Thailand, Vietnam, West Asia, Southeast Asia, Australia, Caribbean, Eastern Mexico, Eastern South America, Western South America, Argentina, Brazil, Canada, Other.

[XXXXXXXXXX] Beach, Robert; McCarl, Bruce, *U.S. Agricultural and Forestry Impacts of the Energy Independence and Security Act: FASOM Results and Model Description*, RTI International, January, 2010.

[YYYYYYYYYY] *Technical Report: An Analysis of EPA Renewable Fuel Scenarios with the FAPRI-CARD International Models*, CARD Staff, December, 2009.

in the model results. For example, since FASOM is a long-term dynamic optimization model, short-term spikes are smoothed out over the five year reporting period. In comparison, the FAPRI-CARD model captures annual fluctuations that may include short-term supply and demand responses. In addition, some of the discrepancies may be attributed to different underlying assumptions pertaining to elasticities of supply and demand for different commodities. These differences, in turn, affect projections of imports and exports, acreage shifting, and total consumption and production of various commodities. Some of the differences in results are described in more detail in the following sections.

### 5.1.2 Model Modifications Since the RFS2 Proposal

Since the analysis for the RFS2 proposal was completed, a number of updates have been made to the FASOM and FAPRI-CARD models to reflect comments received and the availability of new data. The major changes to the agricultural modeling framework include adding price-induced yields, updating cellulosic yields, updating distillers grains replacement rates of corn and soybean meal in animal feed, adding corn oil from extraction as a biodiesel fuel pathway, adding additional land categories in the FASOM model, and adding a detailed Brazil module to the FAPRI-CARD modeling system.

#### 5.1.2.1 Price-Induced Yields

The FAPRI-CARD model includes elasticity factors for yields to respond to changes in prices over time both in the U.S. and internationally. As the price of corn increase, farmers, seed producers, and others involved in crop production have an additional incentive to improve yields. The price induced yield phenomenon is partially offset by the reduced yields that result from expanding on to new crop acres, which is often referred to as extensification. However, the price-induced yield impact is projected to be larger than the extensification effect. For example, in 2022 the price of corn increases by $0.10 (3.3 percent) in the U.S. In response, the average corn yield in 2022 increases by 0.4 bushels per acre (0.4 percent). In another example, in 2022, world corn prices increase by $0.12 per bushel (3.1 percent). As a result, corn yields in China increased from 101.9 bushels per acre in the Reference Case to 102.3 bushels per acre in the Control Case in 2022, a 0.3 percent improvement. Additional details on the methodology behind the estimation of price-induced yields can be found in the FAPRI-CARD Technical Report in the docket.[ZZZZZZZZZZ] Additional international results can be found below in this chapter.

#### 5.1.2.2 Cellulosic Yields

Based on new research conducted by the National Renewable Energy Laboratory (NREL), we have updated the rates of conversion for cellulosic feedstocks into ethanol in the FASOM model.[AAAAAAAAAAA] As a result of these changes, the gallons per ton yields for switchgrass and several other feedstocks increased from the values used in the RFS2 proposal, while the yields for corn residue and several other feedstocks decreased slightly from the values

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[ZZZZZZZZZZ] *Technical Report: An Analysis of EPA Renewable Fuel Scenarios with the FAPRI-CARD International Models*, CARD Staff, December, 2009.

[AAAAAAAAAAA] Tao, Aden, *Technoeconomic Modeling to Support the EPA Notice of Proposed Rulemaking (NOPR)*, Nov. 2008.

used in the proposal. For additional detail, please see chapters 1 and 2. In addition, we also updated our switchgrass production yields based on new work conducted by the Pacific Northwest National Laboratory (PNNL).[BBBBBBBBBBB] In the analysis for the RFS2 proposal, national average switchgrass yields were 6.3 wet tons per acre in the Control Case in 2022. For the final rulemaking analysis, national average switchgrass yields are 7.8 wet tons per acre in the Control Case in 2022. For more information on switchgrass yields, please refer to the FASOM technical documentation.[CCCCCCCCCCC]

### 5.1.2.3 Distillers Grains Replacement Rates

One of the byproducts of the dry mill ethanol processes is the creation of distillers grains with solubles (DGS). This byproduct is a common source of animal feed, and can be used to feed beef cattle, dairy cows, swine, and poultry. When DGS are used in feed, they can replace other sources of feed that would otherwise be used, such as corn and soybean meal. Based on research conducted by Argonne National Laboratory,[DDDDDDDDDDD] one pound of DGS can be used to replace 1.196 pounds of total corn and soybean meal for various beef cattle and dairy cows due to the ability of this livestock to take advantage of the higher nutritional content of DGS per pound compared to corn and soybean meal. Current livestock production practices use 1 pound of DGS to replace 1 pound of a combination of corn and soybean meal. For our analysis, the replacement rates for corn and soybean meal increase steadily over time from a 1:1 replacement rate, to the maximum technological replacement rate of 1:1.196 in 2015 for beef cattle and dairy cows. A replacement rate of 1:1 is used for swine and poultry throughout the time period analyzed. Based on work by Shurson,[EEEEEEEEEEE] DGS produced in combination with the corn oil fractionation/extraction processes has different nutritional characteristics than traditional DGS containing higher levels of oil. According to this research, fractionated/extracted DGS replaces a slightly higher proportion of soybean meal rather than corn compared to traditional DGS when used for swine and poultry feed (although the total displacement rate for both types of DGS is 1:1). We have therefore used these modified replacement rates of corn and soybean meal for fractionated/extracted DGS fed to swine and poultry. The Shurson paper does not include changes in replacement rates of corn and soybean meal for beef cattle and dairy cows, so replacement rates are assumed to be the same for traditional DGS and fractionated/extracted DGS. Maximum inclusion rates for DGS in feed are 40 to 50 percent for beef, 27 to 30 percent for dairy, and 21 to 25 percent for swine and poultry.

### 5.1.2.4 Corn Oil Extraction as Biodiesel Pathway

For the RFS2 analysis, both FASOM and FAPRI-CARD explicitly model corn oil withdrawn from the extraction as a source for biodiesel. Based on engineering research (see

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[BBBBBBBBBBB] Thomson, A.M., R.C. Izarrualde, T.O. West, D.J. Parrish, D.D. Tyler, and J.R. Williams. 2009. *Simulating Potential Switchgrass Production in the United States*. PNNL-19072. College Park, MD: Pacific Northwest National Laboratory.

[CCCCCCCCCCC] Beach, Robert; McCarl, Bruce, *U.S. Agricultural and Forestry Impacts of the Energy Independence and Security Act: FASOM Results and Model Description*, RTI International, January, 2010.

[DDDDDDDDDDD] Salil Arora, May Wu, and Michael Wang, "Update of Distillers Grains Displacement Ratios for Corn Ethanol Life-Cycle Analysis," September 2008. See http://www.transportation.anl.gov/pdfs/AF/527.pdf

[EEEEEEEEEEE] Shurson, *The Value of High-Protein Distillers Coproducts in Swine Feeds,* Distillers Grains Quarterly, First Quarter 2006.

Chapter 1.4) regarding expected technological adoption, it is estimated that 70 percent of dry mill ethanol plants will withdraw corn oil via extraction from distillers grains, resulting in corn oil that is non-food grade and can only be used as a biodiesel source; 20 percent will withdraw corn oil via fractionation (prior to the creation of distillers grains), resulting in corn oil that is food-grade; and 10 percent will do neither extraction or fractionation.

#### 5.1.2.5 Detailed Land Use Categories

Since the proposal, the FASOM model has been updated to include several additional land use categories covering the majority of the U.S. land base. These categories are based on the USDA National Agriculture Statistics Service (NASS) data. These land classifications enable the FASOM model to explicitly link the interaction between livestock, pasture land, cropland, and forest land. For each of these categories, FASOM accounts for how much is actively used in production, and how much idled, in a particular time period. A brief description of these categories is described below. Additional detail on the land categories are included in the technical report on the FASOM model included in the docket.[FFFFFFFFFFF]

- **Cropland** is actively managed cropland, used for both traditional crops (e.g., corn and soybeans) and dedicated energy crops (e.g., switchgrass).
- **Cropland pasture** is managed pasture land used for livestock production, but which can also be converted to cropland production.
- **Forestland** contains a number of sub-categories, tracking the number of acres of private forestland existing at the starting point of the model that remain in standing forests (i.e., have not yet been harvested), the number of acres harvested, the number of harvested acres that are reforested, and the area converted from other land uses (afforested). Public forestland area is not explicitly tracked because it is assumed to remain constant over time, although exogenous estimates of forest products production from these lands are included in the model.
- **Forest pasture** is unmanaged pasture land with varying amounts of tree cover that can be used for livestock production. A portion of this land may be used for timber harvest.
- **Rangeland** is unmanaged land that can be used for livestock grazing production. While the amount of rangeland idled or used for production may vary, it is assumed that rangeland may not be used for any other purpose than for animal grazing due to its low productivity. In addition, much of the rangeland in the U.S. is publicly owned.
- **Developed** (urban) land is assumed to have an inherently higher value than land used for any other use. Thus, the rate of urbanization is assumed to be exogenous based on projections of population and income growth and does not change between the cases analyzed.
- **Conservation Reserve Program (CRP)** refers to land that is voluntarily taken out of crop production and placed in the USDA CRP. Land in the CRP is generally marginal cropland retired from production and converted to vegetative cover, such as grass, trees, or woody vegetation to conserve soil, improve water quality, enhance wildlife habitat, or produce other environmental benefits.

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[FFFFFFFFFFF] Beach, Robert; McCarl, Bruce, *U.S. Agricultural and Forestry Impacts of the Energy Independence and Security Act: FASOM Results and Model Description*, RTI International, January, 2010.

### 5.1.2.6 Brazil Module

In the FAPRI-CARD modeling system, all non-U.S. countries are analyzed at the national level, with the exception of Brazil. Due to the importance of Brazil in determining the international impacts of increased biofuel demand, including the increase in U.S. demand for imported ethanol, the FAPRI-CARD model was updated to include additional agricultural detail in Brazil. The FAPRI-CARD model now includes an integrated Brazil module that provides additional detail on agricultural land use in Brazil for six geographic regions: the Amazon Biome, Northeast (NE), North-Northeast Cerrados (North-NE Cerrados), Central-West Cerrados, Southeast (SE), and the South. The Brazil module explicitly models the competition between cropland and pastureland used for livestock production in each region. In addition, the Brazil module allows for region-specific agriculture practices such as double cropping and livestock intensification in response to higher commodity prices. This level of detail allows for a more refined analysis of land use change and economic impacts in Brazil than a national-level analysis. For more detail on the Brazil module and its development, please refer to the FAPRI-CARD model technical report in the docket.[GGGGGGGGGGG]

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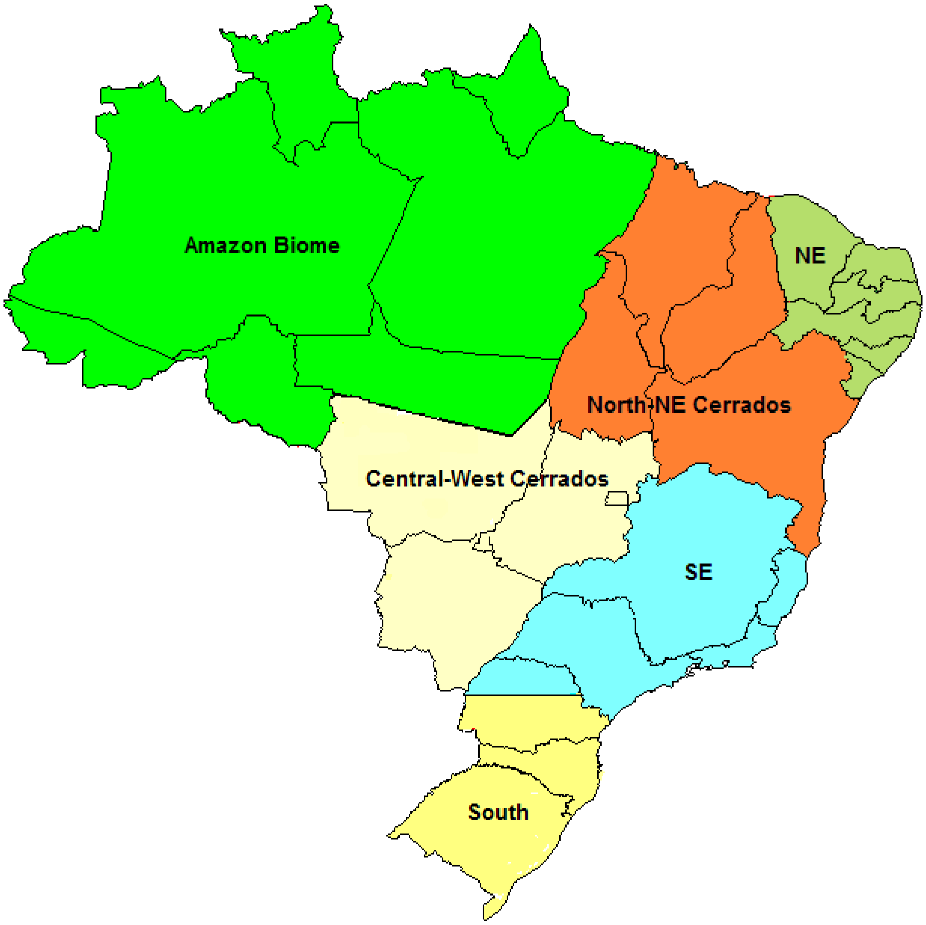
[GGGGGGGGGGG] *Technical Report: An Analysis of EPA Renewable Fuel Scenarios with the FAPRI-CARD International Models*, CARD Staff, December, 2009

**Figure 5.1-1.**
**Map of Brazil by Geographic Region in FAPRI-CARD**



### 5.1.3 Key Modeling Assumptions

To analyze the U.S. and international agriculture sectors impact of the RFS2 renewable fuel volumes, a number of key assumptions and input parameters were standardized in the FASOM and FAPRI-CARD models. These assumptions were developed with the input of other government agencies, such as USDA and DOE. As shown in Table 5.1-1, key assumptions include corn and soybean yields,[HHHHHHHHHHHH] corn ethanol dry and wet mill plant processing energy use, corn ethanol yields, corn ethanol by-product use, estimated corn stover yields, domestic energy prices,[IIIIIIIIII] and others. For other estimates of input parameters, we relied on external expertise, such as the Greenhouse gases, Regulated Emissions and Energy use in

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[HHHHHHHHHHHH] USDA Agricultural Projections to 2018 (OCE-2009-1), February, 2008.

[IIIIIIIIII] Energy prices in all cases are based on the April Release of the 2009 Annual Energy Outlook, published by the Energy Information Administration (EIA) within DOE. Prices used include Gasoline, Diesel, E85, Coal, and Electricity. See: http://www.eia.doe.gov/oiaf/servicerpt/stimulus/index.html

Transportation (GREET) model;[JJJJJJJJJJJ] the Assessment System for Population Exposure Nationwide (ASPEN) model;[KKKKKKKKKKK] and the Agriculture Resource Management Survey (ARMS).[LLLLLLLLLLL] Additional details on the assumptions included in FASOM[MMMMMMMMMMM] and FAPRI-CARD[NNNNNNNNNNN] are included in the docket.

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[JJJJJJJJJJJ] The GREET model is run by Argonne National Laboratory at the Department of Energy. GREET can simulate more than 100 fuel production pathways and more than 80 vehicle/fuel systems.

[KKKKKKKKKKK] ASPEN is a computer simulation model used to estimate toxic air pollutant concentrations is called the Assessment System for Population Exposure Nationwide. This model is based on the EPA's Industrial Source Complex Long Term model (ISCLT) which simulates the behavior of the pollutants after they are emitted into the atmosphere. ASPEN uses estimates of toxic air pollutant emissions and meteorological data from National Weather Service Stations to estimate air toxics concentrations nationwide.

[LLLLLLLLLLL] ARMS is sponsored by the Economic Research Service (ERS) and National Agricultural Statistics Service (NASS) at USDA, and provides observations of field-level farm practices, the economics of the farm business, and the characteristics of the American farm household.

[MMMMMMMMMMM] Beach, Robert; McCarl, Bruce, *U.S. Agricultural and Forestry Impacts of the Energy Independence and Security Act: FASOM Results and Model Description*, RTI International, January, 2010.

[NNNNNNNNNNN] *Technical Report: An Analysis of EPA Renewable Fuel Scenarios with the FAPRI-CARD International Models*, CARD Staff, December, 2009.

## Table 5.1-1.
## Agriculture Model Assumptions

| Assumption | Notes |
|---|---|
| **Feedstock Production** | |
| Prices for Gasoline, Diesel, E85, Coal, and Electricity used in all volume cases | AEO 2009, April Release |
| U.S. national average corn yields are approximately 170 bu/acre in 2017 and 180 bu/acre in 2022 (a 1.6% annual increase over the baseline year) | Consistent with USDA projections (http://www.ers.usda.gov/publications/oce081/) |
| U.S. national average soybean yields are approximately 50 bu/acre in 2022 (a 0.4% annual increase) | |
| International corn yields increasing over time, for example:<br>Argentina ~134 bu/acre in 2022 (a 1.2% annual increase)<br>Brazil ~72 bu/acre in 2022 (a 1.7% annual increase) | FAPRI-CARD Models |
| International soybean yields increasing over time, for example:<br>Argentina ~46 bu/acre in 2022 (a 0.9% annual increase)<br>Brazil ~46 bu/acre in 2022 (a 0.9% annual increase) | |
| Price-Induced Yields, for example:<br>World Price of Corn increases by 3.1% from the Reference Case to the Control Case in 2022;<br>Corn Yields in China increases by 0.3% from the Reference Case to the Control Case in 2022 | |
| High Yield sensitivity runs for corn and soybeans:<br>For example, U.S. High Yields in 2022:<br>Corn: approximately 232 bu/acre (28% higher than Base Yield)<br>Soybeans: approximately 61 bu/acre (31% higher than Base Yield)<br>Similar yield increases for top producers of corn (China, Mexico, EU, Argentina, Brazil) and soybeans (China, Argentina, Brazil) | FASOM and FAPRI-CARD Models<br>Represented as increases in technological rates of progress, no additional inputs required |
| Corn residue removal rates of 50% are allowed for no till practices; 35% removal rate allowed for reduced till practices (no removal from conventional till) | Derived from Graham et. al., Agronomy Journal, 99:1–11 (2007). “Current and Potential U.S. Corn Stover Supplies.” and Perlack, R. D., L. L. Wright, A. F. Turhollow, R. L. Graham, B. J. Stokes, and D. C. Erbach. 2005. Biomass as Feedstock for a Bioenergy and Bioproducts Industry: the Technical Feasibility of a Billion-ton Annual Supply. Report prepared for the U.S. Department of Energy and the U.S. Department of Agriculture. |

| | |
|---|---|
| Updated Conversion Rates (gallons per dry ton) for all cellulosic ethanol feedstock sources.<br>For example:<br>Proposal Analysis:<br>Corn Resiude: 94.2 gallons/dry ton<br>Switchgrass: 78.9 gallons/dry ton<br>Final Rule Analysis:<br>Corn Resiude: 92.3 gallons/dry ton<br>Switchgrass: 92.3 gallons/dry ton | Based on NREL Research<br>Tao, Aden, *Technoeconomic Modeling to Support the EPA Notice of Proposed Rulemaking (NOPR)*, Nov. 2008. |
| Switchgrass Yields by Region in the U.S. | Based on preliminary PNNL Research |
| Non-Food Grade (NFG) Corn Oil modeled in FASOM and FAPRI-CARD as a biodiesel feedstock.<br>NFG Corn Oil is a byproduct of the extraction and fractionation processes of dry mill ethanol plants. | Based on engineering cost projections and expected rates of technology adoption. See Chapter 1 of the RIA.<br>By 2022: 70% of dry mill ethanol plants will conduct extraction, 20% will conduct fractionation, and 10% will do neither |
| The Conservation Reserve Program (CRP) has a maximum limit of 32 million acres enrolled in the program at any given time | 2008 Farm Bill<br>USDA baseline assumptions |
| **Fertilizer Use** | |
| U.S. nitrogen application rate for corn is approximately 136 lbs/acre in the corn belt in 2022<br>U.S. phosphorous application rate for corn is approximately 28 lbs/acre in the corn belt in 2022 | Based on ARMS data, adjusted for differences in regions and irrigation practices |
| For U.S. assume higher yields require no increase in fertilizer use | Based on USDA baseline assumptions<br>This holds for all farming rotations (e.g., corn / soybean and corn / corn) and land types (e.g., prime and marginal land); see below for stover removal impacts |
| Nitrogen nutrient replacement application = 7 lbs/ton corn residue removed<br>Phosphorous nutrient replacement application = 3.6 lbs/ton corn residue removed | These numbers come from the Argonne National Lab Report, Fuel Cycle Assessment of Selected Bioethanol Production Pathways in the United States. (November 7, 2006). (Used and cited by GREET) |
| **Processing** | |
| 1 bushel of corn produces 17 lbs of dried distillers grains (dry tons).<br>1 pound of DGS substitutes 1.196 pounds of corn and soybean meal feed for beef cattle, dairy cows by 2015<br>1 pound of DGS substitutes 1 pound of corn and soybean meal feed for swine and poultry, with adjustments for fractionated/extracted DGS | www.ethanol.org<br>Argonne National Laboratory: Update of Distillers Grains Displacement Ratios for Corn Ethanol Life-Cycle Analysis," September 2008<br>Shurson: The Value of High-Protein Distillers Coproducts in Swine Feeds, Distillers Grains Quarterly, First Quarter 2006. |

Projected crop yields, both domestically and internationally, are an important factor in the analysis of increased renewable fuel volumes. The U.S. yields presented in Table 5.1-1 are based on the USDA projections through 2018 (the last year of the USDA baseline projections report) and then extrapolated out to 2022. The U.S. yields in this table represent the national weighted average yields, with yields varying across regions. Regional yields are based on historical averages for the region. Although the initial crop yields vary by region, the regional yield for each crop is increased at the same crop-specific annual percentage rate. For instance, FASOM assumes the rate of increase for corn yields are 1.6 percent per year. The rates of increase are assumed to be the same in both the AEO 2007 Reference Case and the EISA Control Case.

The international crop yields included in FAPRI-CARD are different for each country and for each crop. The FAPRI-CARD model bases each country's crop yield on historical trends and projects this technical rate of progress into the future. As described in the previous section, the FAPRI-CARD model also incorporates yield responses to changes in price and for expansion onto marginal lands. Examples of how yields vary by region and crop are included in Table 5.1-1.

For the lifecycle analysis, sensitivity runs were conducted in both FASOM and FAPRI-CARD to observe the effects of higher yields for both corn and for soybeans. The assumption behind these high-yield runs is that the technological rate of progress over time is higher for corn and soybeans than compared to our "base yield" modeling efforts used for the rulemaking impacts. This increase in the technological rate of progress begins in 2012 in the FASOM model, and in 2010 in the FAPRI-CARD model (the next future time period in each respective model). By 2012, Corn yields in the U.S. are 7.1 percent higher in the High Yield Control Case than in the Base Yield Control Case. By 2017, it is 18 percent higher, and by 2022 it is 30 percent higher. Similarly, soybean yields in the U.S. are 7.8 percent higher in 2012, 20 percent higher in 2017, and 31 percent higher in the High Yield Control Case than in the Base Yield Control Case. In the FAPRI-CARD model, similar increases in technological rates of progress for corn were applied to other top corn producers (China, Mexico, the EU, Argentina, and Brazil), and likewise for other top soybean producers (China, Argentina, and Brazil). Results from these high yield sensitivity runs can be found in Chapter 2 of the RIA. Table 5.1-2 lists the yields for the top producers of corn and soybeans in the Control Case in 2022, both for the "base" results and for the "high-yield" results. For overall impacts of the "high-yield" sensitivity model runs, please refer to Chapter 2.

### Table 5.1-2.
### Corn and Soybean Yields of Top Producers in the Control Case in 2022 with “Base Yield” and “High-Yield” Sensitivity Runs
### (bushels per acre)

| Corn | | | |
|---|---|---|---|
| **Country** | **Base Yield** | **High Yield** | **% Difference** |
| U.S. | 181.2 | 231.6 | 27.9% |
| China | 102.3 | 129.9 | 27.0% |
| Mexico | 55.8 | 70.9 | 27.0% |
| EU | 110.5 | 140.4 | 27.0% |
| Argentina | 133.9 | 170.1 | 27.0% |
| Brazil * | 72.2 | 81.8 | 13.3% |
| **Soybeans** | | | |
| **Country** | **Base Yield** | **High Yield** | **% Difference** |
| U.S. | 46.0 | 60.5 | 31.4% |
| China | 29.8 | 38.9 | 30.4% |
| Argentina | 46.1 | 60.1 | 30.4% |
| Brazil * | 46.3 | 57.8 | 25.0% |

* Note: Yields in individual regions in Brazil are 27% higher than in the Base yield, similar to other countries. However, since some regions are more productive than others, the regional distribution of soybean production is different between the “Base” and “High-Yield” model runs. This results in the overall yields of corn and soybeans in Brazil in the “High Yield” sensitivity run to not be the same percentage higher than the “Base” model run compared to other countries.

For cellulosic biofuels from corn residues, the current assumptions in FASOM for residue removal rates are based on the Graham et. al. paper[OOOOOOOOOOO] and the Perlack et. al. study.[PPPPPPPPPPP] This approach uses a maximum percent removal of residues on acres based on tillage practices.[QQQQQQQQQQQ] Although we requested comment on whether a better metric is the minimum amount of mass that must remain on an acre of land to prevent runoff and maintain soil carbon levels, we did not receive sufficient data to incorporate this approach into our modeling framework.[RRRRRRRRRRR]

FASOM assumes fertilizer application rates do not increase over time in proportion to the increase in yields (i.e., delinks fertilizer application rates and crop yield changes through time). The principal reason for this is USDA data that shows fertilizer application rates per acre remaining relatively steady for the past 30 years, during which time corn yields have increased approximately 70 percent.[SSSSSSSSSSS] However, when residues are removed from the field, some of the nutrients that are contained in the residue must be replaced through additional fertilizer use. For the analysis, we assumed that 7 additional pounds of nitrogen and 3.6 pounds of phosphorous must be applied per ton of corn stover residue removed. [TTTTTTTTTTT]

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[OOOOOOOOOOO] See also http://www.cpnrd.org/Harvesting%20Stover.pdf

[PPPPPPPPPPP] Available at http://feedstockreview.ornl.gov/pdf/billion_ton_vision.pdf.

[QQQQQQQQQQQ] Many site specific factors associated with the sustainable removal of residue (e.g., crop type, soil type, soil fertility, slope, and climate) affect which geographic regions are suitable for crop residue removal. Detailed modeling of these factors was beyond the scope of this analysis.

[RRRRRRRRRRR] Wilhelm et. al Corn Stover to Sustain Soil Organic Carbon Further Constrains Biomass Supply, Ag Journal (2007)

[SSSSSSSSSSS] Data from the National Agriculture Statistics Service (NASS) at USDA: http://www.nass.usda.gov/

[TTTTTTTTTTT] Wu, M., M. Wang, and H. Huo. Fuel-Cycle Assessment of Selected Bioethanol Production Pathways in the United States. ANL/ESD/06-7. November 2006.

Lastly, there is a limit to how many acres of cropland can be placed in the Conservation Reserve Program (CRP).[UUUUUUUUUUU] CRP is run by the Natural Resources Conservation Service at USDA. This program is designed to maintain Federal, State, and tribal environmental laws by making payments to farmers equivalent to the income otherwise earned from developing the land enrolled in the program. In the 2008 Farm Bill, the number of acres enrolled in the CRP was given a maximum limit of 32 million acres. Based on input from USDA, we assumed that USDA will increase payments to maintain 32 million acres in CRP through 2022.

### 5.1.4 Volumes

For the agricultural sector analysis, we modeled the AEO2007 Reference Case and the Control Case (i.e., EISA mandated) volumes described in Chapter 1.2. Where possible, we modeled the same volumes in both FASOM and FAPRI-CARD. However, some of the projected future sources of renewable fuels are not explicitly included in both models. For example, since FASOM is a domestic agriculture and forestry model, it cannot explicitly model U.S. biofuel imports and their impacts on worldwide trade and land use as the FAPRI-CARD model does. In addition, the FAPRI-CARD model does not currently model cellulosic renewable fuel feedstock production. Therefore, the cellulosic renewable fuel analysis relies on results from the FASOM model.[VVVVVVVVVVV] Neither of the two models used for this analysis — FASOM or FAPRI-CARD — include biofuel produced from domestic municipal solid waste (MSW). Thus, for the RFS2 analysis, this biofuel was modeled outside of the agriculture sector. For more information on how MSW was modeled elsewhere in the RFS2 analysis, please see Chapters 1 and 2. We estimate that approximately 2.3 Bgal of cellulosic renewable fuels will be produced from municipal solid waste in 2022.

All the results presented in the following section are relative to the AEO 2007 Reference Case renewable fuel volumes, which include 12.3 Bgal of grain-based ethanol, 0.1 Bgal of biodiesel from soybean oil, 0.3 Bgal of biodiesel from waste oils and greases, 0.3 Bgal of cellulosic ethanol, and 0.6 Bgal of imported ethanol in 2022. The domestic figures are provided by FASOM and FAPRI-CARD, and all of the international numbers are provided by FAPRI-CARD. For a more detailed set of results of the agricultural sector impacts of the RFS2 volumes, see the analytical reports submitted by the FASOM and FAPRI-CARD modeling groups in the docket of this rule.

For ethanol, we assumed 15 billion gallons (Bgal) of corn ethanol would be produced for use as transportation fuel in the U.S. by 2022 in the Control Case in both FASOM and FAPRI-CARD. FASOM modeled an increase of 13.5 Bgal of cellulosic renewable fuel from the Reference Case in 2022.[WWWWWWWWWWW] To satisfy the cellulosic renewable fuel requirements, the FASOM model was allowed to choose how much cellulosic renewable fuel was produced

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[UUUUUUUUUUU] See: http://www.nrcs.usda.gov/programs/CRP/

[VVVVVVVVVVV] The FAPRI-CARD model was used to estimate the indirect land use effects of additional switchgrass acres on other crops in the U.S., as shown by the FASOM model, and the resultant impacts on trade and land use worldwide. Please refer to Chapter 2 of the RIA for more information.

[WWWWWWWWWWW] FASOM does not include renewable diesel or biomass to liquids as potential cellulosic pathways, therefore all cellulosic volumes were assumed to be ethanol.

from different feedstocks, taking account the various harvesting and processing costs and the income the agriculture and forestry sectors derive from each feedstock. FASOM projects that 7.9 Bgal of cellulosic renewable fuel will be produced from switchgrass in 2022, 4.9 Bgal from corn residue, 0.4 Bgal from sugarcane bagasse, and 0.1 billion gallons from forestry logging and milling residues. FAPRI-CARD modeled an increase of 1.6 Bgal from ethanol imported to the U.S. over the AEO2007 Reference Case level in 2022.

For biodiesel, both FASOM and FAPRI-CARD modeled an increase of 0.5 Bgal of biodiesel produced from soybean oil above the AEO2007 Reference Case in 2022. FASOM and FAPRI-CARD also modeled an increase of 0.1 Bgal of biodiesel produced from various animal fats, waste oils, and greases to 0.4 Bgal in the Control Case in 2022. Similarly, FASOM and FAPRI-CARD modeled an increase of 0.6 Bgal of biodiesel from non-food grade corn oil. This non-food grade corn oil used for biodiesel production is a byproduct of dry mill ethanol plants that undertake the extraction processes.

**Table 5.1-3.**
**Biofuel Volumes Modeled in 2022**
**(Billions of Gallons)**

| Biofuel | AEO2007 Reference Case | Control Case | Change |
|---|---|---|---|
| Corn Ethanol | 12.3 | 15.0 | 2.7 |
| Switchgrass Cellulosic Ethanol | 0 | 7.9 | 7.9 |
| Corn Residue Cellulosic Ethanol | 0 | 4.9 | 4.9 |
| Sugarcane Bagasse Cellulosic Ethanol | 0.2 | 0.6 | 0.4 |
| Forest Residue Cellulosic Ethanol | 0 | 0.1 | 0.1 |
| Imported Ethanol | 0.6 | 2.2 | 1.6 |
| Total Ethanol (FASOM) | 12.5 | 28.7 | 16.2 |
| Total Ethanol (FAPRI-CARD) | 13.2 | 17.5 | 4.3 |
| Soybean Oil Biodiesel | 0.1 | 0.6 | 0.5 |
| Corn Oil NFG Biodiesel | 0.0 | 0.6 | 0.6 |
| Biodiesel from Other Fats, Oils, Greases | 0.3 | 0.4 | 0.1 |
| Total Biodiesel | 0.4 | 1.7 | 1.3 |

### 5.1.5 Domestic Agricultural Impacts

For this economic analysis, the FASOM model is utilized for all domestic agriculture impacts. Although the FAPRI-CARD models do not provide the same amount of detail on GHG emissions for the domestic agriculture impacts as the FASOM model, FAPRI-CARD does estimate some of the same outputs, such as national crop acres, prices, and exports. In this section, we present both the FASOM and FAPRI-CARD results to demonstrate the range of potential agricultural impacts. Presenting both sets of results allows for a useful comparison between the two models, reinforces the accuracy of our domestic analysis, and ensures consistency when analyzing the impacts of the RFS2 fuel volume requirements on the domestic and international agriculture markets.

#### 5.1.5.1 Commodity Prices

To meet the RFS2 renewable fuel volumes, there are a number of price effects on the agricultural commodities. For instance, FASOM estimates that the Control Case renewable fuel volumes result in an increase in the U.S. corn price of \$0.27 per bushel (8.2 percent) above the Reference Case price in 2022. By 2022, FASOM projects that U.S. soybean prices increase by \$1.02 per bushel (10.3 percent) above the Reference Case price. FASOM also projects the price of soybean oil increases by \$183 per ton (37.9 percent) over the 2022 Reference Case price. In 2022, FAPRI-CARD projects that the price of corn increases by \$0.10 per bushel (3.3 percent), the price of soybeans increases by \$0.07 per bushel (0.9 percent), and the price of soybean oil increases by \$12.35 (1.6 percent) relative to the AEO2007 Reference Case.

FASOM projects that the price of switchgrass increases by \$20.12 per wet ton as a result of the Control Case renewable fuel volumes in 2022. Similarly, the price of corn residue increases by \$29.48 per wet ton in 2022, relative to the AEO2007 reference case. FASOM also projects that the Control Case price of sugarcane bagasse increases by \$23.27 per wet ton in 2022. By 2022, FASOM projects that hardwood and softwood logging residues are used to produce cellulosic ethanol, and their prices are \$23.22 per wet ton and \$18.37 per wet ton, respectively, in 2022 in the Control Case. These prices do not include the storage, handling, or delivery costs. Since the FAPRI-CARD models do not explicitly model cellulosic ethanol production from agriculture residues or dedicated energy crops, comparable price impacts are not available. Additional details on the changes in commodity prices are included in Table 5.1.4.

The prices for byproducts of renewable fuel production are also affected by the increased demand for renewable fuels required by the RFS2 rule. Soybean meal, while not exclusively used for animal feed, is an important element of the feed market. In 2022, FASOM projects that the price of soybean meal decreases by \$0.48 per ton (-0.1 percent) relative to the AEO2007 Reference Case. In 2022, FASOM projects the price of fractionated/extracted DGS increases by \$7.69 per ton (6.5 percent) relative to the AEO2007 Reference Case. FASOM projects that the price of traditional DGS, produced by corn ethanol plants that do not conduct fractionation or extraction of corn oil, increases by \$7.94 per ton (6.8 percent) relative to the AEO2007 Reference Case in 2022. In FAPRI-CARD, the price of soybean meal increases by \$1.05 (0.5 percent), and the price of DGS increases by \$3.52 per ton (3.9 percent) in 2022 relative to the AEO2007 Reference Case.

### Table 5.1-4.
### U.S. Commodity Prices in 2022
### (2007$ per Unit)

| Biofuel Feedstocks | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Commodity (Unit)** | **FASOM** | | | | **FAPRI-CARD** | | | |
| | **AEO 2007 Reference Case** | **Control Case** | **Change** | **% Change** | **AEO 2007 Reference Case** | **Control Case** | **Change** | **% Change** |
| Corn (bushel) | $3.32 | $3.60 | $0.27 | 8.2% | $2.96 | $3.06 | $0.10 | 3.3% |
| Soybeans (bushel) | $9.85 | $10.87 | $1.02 | 10.3% | $8.12 | $8.19 | $0.07 | 0.9% |
| Soybean Oil (ton) | $483.10 | $666.42 | $183.32 | 38% | $782.13 | $794.48 | $12.35 | 1.6% |
| Switchgrass (wet ton) | $20.73 | $40.85 | $20.12 | 97% | N/A | N/A | N/A | N/A |
| Corn Residue (wet ton) | $5.01 | $34.49 | $29.48 | 588% | N/A | N/A | N/A | N/A |
| Bagasse (wet ton) | $6.43 | $29.70 | $23.27 | 362% | N/A | N/A | N/A | N/A |
| Hardwood Logging Residue (wet ton) | $5.37 | $23.22 | $17.85 | 332% | N/A | N/A | N/A | N/A |
| Softwood Logging Residue (wet ton) | $9.37 | $18.37 | $8.99 | 96% | N/A | N/A | N/A | N/A |
| **Byproducts** | | | | | | | | |
| **Commodity (Unit)** | **FASOM** | | | | **FAPRI-CARD** | | | |
| | **AEO 2007 Reference Case** | **Control Case** | **Change** | **% Change** | **AEO 2007 Reference Case** | **Control Case** | **Change** | **% Change** |
| Soybean Meal (ton) | $402.11 | $401.63 | -$0.48 | -0.1% | $206.81 | $207.87 | $1.05 | 0.5% |
| DGS Traditional (ton) | $116.75 | $124.69 | $7.94 | 6.8% | N/A | N/A | N/A | N/A |
| DGS Fractionated/Extracted (ton) | $118.88 | $126.57 | $7.69 | 6.5% | N/A | N/A | N/A | N/A |
| DGS (Overall, FAPRI-CARD) | N/A | N/A | N/A | N/A | $90.60 | $94.12 | $3.52 | 3.9% |

### 5.1.5.2 Commodity Use Changes

The increased demand for renewable fuels also affects the use of these feedstocks in other markets. This section will review the use of these commodities for biofuels, their levels of exports, and their use in the animal feed market. In 2022, FASOM projects an additional 1 billion bushels of corn will be used for corn ethanol production (22 percent) relative to the Reference Case. FASOM also projects that in 2022, an additional 98 million wet tons of switchgrass, 60 million wet tons of corn residue, 6.1 million tons of sugarcane bagasse, and 1.7 million tons of forestry residues will be used to produce cellulosic ethanol, relative to the AEO2007 Reference Case.

FASOM estimates that an additional 2 million tons of soybean oil is used to produce soybean biodiesel in 2022, relative to the AEO2007 Reference Case. In addition, FASOM projects that an additional 17.5 million tons of non-food grade corn oil from the extraction process will be used for biodiesel production in 2022.

The increase in renewable fuel volumes required by the RFS2 also impacts U.S. exports. For instance, FASOM estimates that the amount of corn exported from the U.S. decreases by 188 million bushels (-8.2 percent) in 2022, relative to the AEO2007 Reference Case. This change represents a decrease of $57 million (-0.8 percent) in the total value of corn exports in the FASOM model in 2022. In FAPRI-CARD, U.S. corn exports decrease by 407 million bushels (-15.7 percent) in 2022. This change translates into a decrease in the total value of corn exports of $991 million (-12.9 percent) in 2022.

Similarly, as more soybean oil is used for biodiesel production, the amount of soybeans and soybean oil exported from the U.S. can be expected to be affected. In FASOM, soybean exports decrease by 135 million bushels (-13.6 percent) in 2022 relative to the AEO2007 Reference Case. This change represents a decrease of $453 million (-4.6 percent) in the total value of U.S. soybean exports in 2022. In FAPRI-CARD, soybean exports decrease by 32 million bushels (-3 percent), relative to the AEO2007 Reference Case. This change represents a decrease in the total value of U.S. soybean exports of $185 million (-2.1 percent) in 2022. The FASOM model projects that U.S. soybean oil exports decrease by 1.2 million tons (-51 percent) in 2022 relative to the AEO2007 Reference Case. In the FAPRI-CARD model, soybean oil exports decrease by 0.3 million tons (-6.2 percent) in 2022 relative to the AEO2007 Reference Case.

**Table 5.1-5.**
**U.S. Exports in 2022**

| **Exports (millions of units)** | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| **Commodity (Unit)** | **FASOM** | | | | **FAPRI-CARD** | | | |
| | **AEO 2007 Reference Case** | **Control Case** | **Change** | **% Change** | **AEO 2007 Reference Case** | **Control Case** | **Change** | **% Change** |
| Corn (bushel) | 2,281 | 2,093 | -188 | -8.2% | 2,589 | 2,182 | -407 | -15.7% |
| Soybeans (bushel) | 993 | 858 | -135 | -13.6% | 1,073 | 1,041 | -32 | -3.0% |
| Soybean Oil (ton) | 2.3 | 1.1 | -1.2 | -51.2% | 4.8 | 4.5 | -0.3 | -6.2% |
| **Total Value of Exports (millions of 2007$)** | | | | | | | | |
| **Commodity** | **FASOM** | | | | **FAPRI-CARD** | | | |
| | **AEO 2007 Reference Case** | **Control Case** | **Change** | **% Change** | **AEO 2007 Reference Case** | **Control Case** | **Change** | **% Change** |
| Corn | $7,585 | $7,527 | -$57 | -0.8% | $7,669 | $6,679 | -$991 | -12.9% |
| Soybeans | $9,780 | $9,327 | -$453 | -4.6% | $8,709 | $8,524 | -$185 | -2.1% |

Higher U.S. demand for renewable fuels leads to an increase in the price of corn and causes a decrease in the use of corn for U.S. livestock feed. Substitutes are available for feed corn and this market is price sensitive. The total amount of corn used for feed in FASOM decreases by 3.3 million tons (-2.5 percent) in 2022 relative to the AEO2007 Reference Case. Several ethanol processing byproducts can be used to replace a portion of the corn used as feed, depending on the type of animal. DGS are a byproduct of the dry milling process, whereas gluten meal and gluten feed are byproducts of wet milling corn ethanol production. FASOM estimates that total DGS used in feed increases by 5.2 million tons (15.2 percent), gluten meal used in animal feed decreases by 0.1 million tons (-4.5 percent), and gluten feed use increases by 0.3 million tons (6.4 percent) in 2022 relative to the AEO2007 Reference Case. As DGS are used more in the feed market in the Control Case than in the Reference Case, corn and soybean meal used in the feed market is replaced. Thus, soybean meal used in feed decreases by 0.04 million tons (-0.4 percent) in 2022 to 10.5 million tons in the Control Case. Overall, the total ethanol byproducts used in feed (DGS, gluten meal, and gluten feed) increase by 5.4 million tons (13.2 percent) in 2022 relative to the AEO2007 Reference Case.

**Table 5.1-6.**
**Animal Feed Sources in 2022**
**(millions of tons)**

| Feed Source | FASOM | | | | FAPRI-CARD | | | |
|---|---|---|---|---|---|---|---|---|
| | AEO 2007 Reference Case | Control Case | Change | % Change | AEO 2007 Reference Case | Control Case | Change | % Change |
| Corn | 134.4 | 131.1 | -3.3 | -2.5% | 158.8 | 152.3 | -6.5 | -4.1% |
| Soybean Meal | 10.53 | 10.49 | -0.04 | -0.4% | 39.4 | 38.7 | -0.7 | -1.7% |
| DGS Total | 34.1 | 39.3 | 5.2 | 15.2% | 33.9 | 39.1 | 5.2 | 15.2% |
| Gluten Meal | 2.2 | 2.1 | -0.1 | -4.5% | 1.0 | 1.1 | 0.1 | 7.5% |
| Gluten Feed | 4.5 | 4.8 | 0.3 | 6.4% | 7.6 | 7.9 | 0.3 | 4.1% |
| Total Ethanol Byproducts | 40.7 | 46.1 | 5.4 | 13.2% | 42.5 | 48.1 | 5.5 | 13.0% |

### 5.1.5.3 Changes in Crop Acres

In order to meet the Control Case volumes of renewable fuels, FASOM estimates an increase of 3.6 million acres (4.6 percent) for harvested corn acres in 2022.[xxxxxxxxxxx] Most of the new corn acres come from a reduction in existing crop acres, such as rice, wheat, barley, rye and hay. FASOM projects that rice acres decrease by 788 thousand acres (-20.6 percent), wheat acres decrease by 2.9 million acres (-4.9 percent), and hay acres decrease by 752 thousand acres (-1.5 percent) in 2022 relative to the AEO2007 Reference Case. See Table 5.1-7 for additional changes in crop acres in the FASOM and FAPRI-CARD models.

Although the RFS2 Control Case includes more soybean biodiesel than the AEO2007 Reference Case, competing demands for land results in a decrease in U.S. harvested soybean acres. According to the FASOM model, harvested soybean acres decrease by approximately 1.4 million acres (-2.1 percent) in 2022 relative to the Control Case. As described in the previous section, most of the additional soybeans needed for increased biodiesel production are diverted from exports. FAPRI-CARD also projects that the increased demand for biodiesel from soybean oil results chiefly in a reduction in soybean oil exports, rather than an increase in acres harvested. FAPRI-CARD projects that harvested soybean acres decrease by 0.9 million acres (-1.1 percent) in 2022 relative to the AEO2007 Reference Case.

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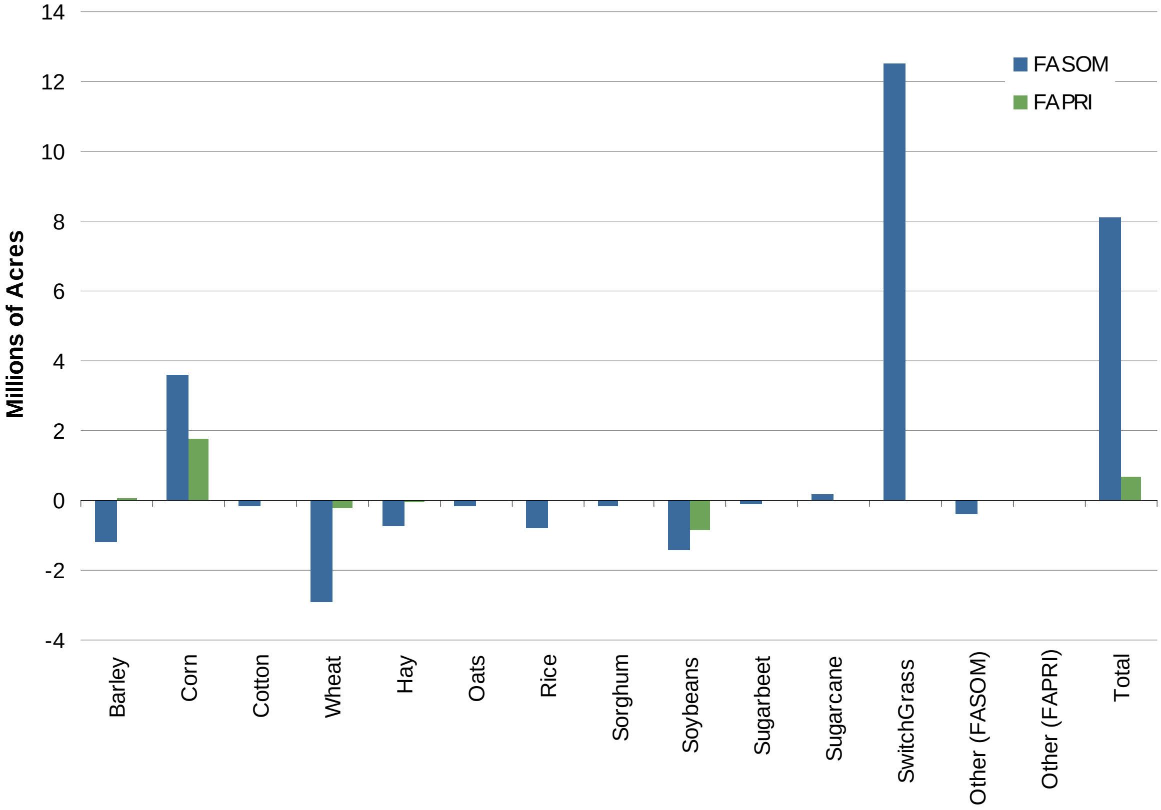
[xxxxxxxxxxx] FASOM estimates that total planted corn acres increase to 89.4 million acres in the Control Case from the Reference Case level of 84.6 million acres in 2017. Total planted acres increases to 87.1 million acres in the Control Case from the Reference Case level of 83.5 million acres in 2022.

As the demand for cellulosic renewable fuels increases, FASOM projects that most of the cellulosic biofuels will be derived from switchgrass. In 2022, switchgrass acres increase by 12.5 million acres, relative to the AEO2007 Reference Case. The remainder of the cellulosic biofuel is produced from corn residue, forestry residues, and sugarcane bagasse. The FAPRI-CARD models do not explicitly model the production of cellulosic renewable fuel, nor does it explicitly model the feedstocks for cellulosic renewable fuel. Table 5.1-7 and Figure 5.1-2 shows the change in acres for all crops in the U.S. in 2022.

**Table 5.1-7.**
**U.S. Crop Acres in 2022**
**(millions of acres)**

| Crop | FASOM | | | | FAPRI-CARD | | | |
|---|---|---|---|---|---|---|---|---|
| | AEO 2007 Reference Case | Control Case | Change | % Change | AEO 2007 Reference Case | Control Case | Change | % Change |
| Barley | 9.7 | 8.5 | -1.2 | -12.4 | 2.96 | 3.0 | 0.04 | 1.2% |
| Corn | 77.9 | 81.5 | 3.6 | 4.6% | 79.1 | 80.9 | 1.8 | 2.2% |
| Cotton | 11.3 | 11.1 | -0.2 | -1.7% | 7.7 | 7.7 | 0.0 | 0.1% |
| Wheat | 59.0 | 56.0 | -2.9 | -4.9% | 48.3 | 48.1 | -0.2 | -0.5% |
| Hay | 50.7 | 50.0 | -0.8 | -1.5% | 60.8 | 60.8 | 0.0 | -0.1% |
| Oats | 5.5 | 5.4 | -0.2 | -3.2% | 1.1 | 1.1 | 0.0 | -1.0% |
| Rice | 3.8 | 3.0 | -0.8 | -20.6% | 2.6 | 2.6 | 0.0 | 0.0% |
| Sorghum | 8.7 | 8.5 | -0.2 | -1.8% | 5.8 | 5.8 | 0.0 | 0.3% |
| Soybeans | 68.1 | 66.6 | -1.4 | -2.1% | 78.3 | 77.4 | -0.9 | -1.1% |
| Sugarbeet | 1.3 | 1.2 | -0.1 | -7.8% | 1.2 | 1.2 | 0.0 | -0.3% |
| Sugarcane | 0.7 | 0.9 | 0.1 | 19.8% | 0.8 | 0.8 | 0.0 | 0.2% |
| Switchgrass | 0.1 | 12.6 | 12.5 | 20,261% | 0.0 | 0.0 | 0.0 | N/A |
| Other (FASOM)* | 9.5 | 9.1 | -0.4 | -4.4% | N/A | N/A | N/A | N/A |
| Other (FAPRI-CARD)** | N/A | N/A | N/A | N/A | 4.7 | 4.7 | 0.0 | 0.1% |
| Total | 306.3 | 314.4 | 8.1 | 2.6% | 288.7 | 289.4 | 0.7 | 0.2% |

Figure 5.1-2.
Estimated Change in U.S. Crop Acres
Relative to the AEO 2007 Reference Case in 2022



As switchgrass and corn residue are the largest feedstocks of cellulosic renewable fuel, it is important to know which regions in the U.S. these feedstocks are the most competitive. Corn residue removal takes place chiefly in the Corn Belt region of the U.S. Based on the residue removal rates outlined in Table 5.1-1, corn acres with residue removal in the Control Case takes place mostly in Iowa (9 million acres) and Illinois (7.4 million acres). Switchgrass production, on the other hand, takes place mostly in the Southwest region of the U.S. This includes 2.7 million acres in Kansas, 1.7 million acres each in Missouri and Texas, as well as 1.3 million acres in Oklahoma. To see the top ten producing states for corn residue and switchgrass, please refer to Figures 5.1-3 and 5.1-4 below.

## Figure 5.1-3.
## Top Ten Producing States of Corn Acres with Residue Removal in 2022
## FASOM Control Case

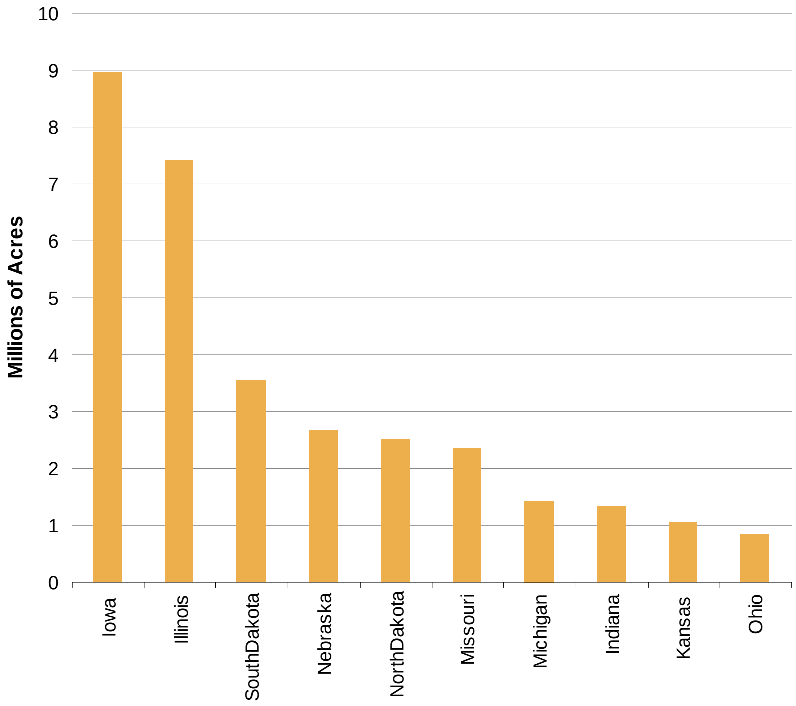
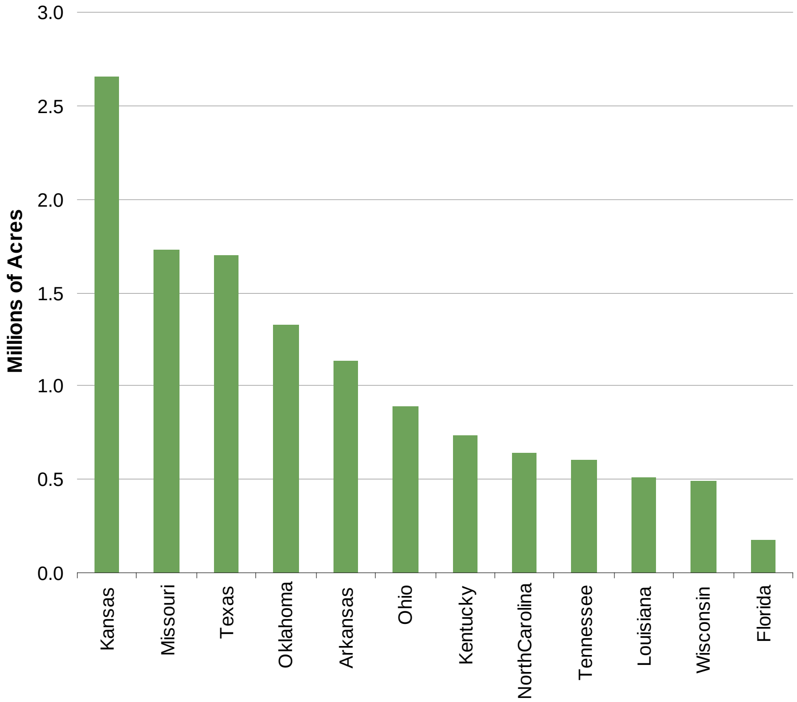


**Figure 5.1-4.**
**Top Ten Producing States of Switchgrass in 2022**
**FASOM Control Case**



## 5.1.5.4 Land Use Change

Changes in these land categories are summarized in Table 5.1-8 below. In 2022, FASOM projects that total cropland increases by 3.1 million acres (1.0 percent) relative to the Reference Case. The increase in cropland is derived primarily from a combination of decreased cropland pasture acres, and a decrease in forest acres. FAPRI-CARD does not explicitly model U.S. forest or pasture acres.

### Table 5.1-8.
### Change in U.S. Major Land Use Categories in 2022 Relative to the Reference Case (millions of acres)

| Land Category | AEO 2007 Reference Case | Control Case | Change | % Change |
|---|---|---|---|---|
| Cropland | 311.7 | 314.8 | 3.1 | 1.0% |
| Used for Production | 306.3 | 314.4 | 8.1 | 2.6% |
| Idled | 5.4 | 0.4 | -5.0 | -93.0% |
| Cropland Pasture | 32.0 | 30.1 | -1.9 | -5.8% |
| Used for Production | 23.1 | 25.0 | 1.8 | 8.0% |
| Idled | 8.9 | 5.2 | -3.7 | -41.7% |
| Forest Pasture | 148.4 | 149.5 | 1.1 | 0.7% |
| Used for Production | 113.1 | 114.4 | 1.3 | 1.1% |
| Idled | 35.3 | 35.1 | -0.2 | -0.5% |
| Forestland | 344.5 | 343.3 | -1.2 | -0.3% |
| Rangeland | 578.8 | 578.8 | 0 | 0% |
| Used for Production | 522.6 | 516.8 | -5.8 | -1.1% |
| Idled | 56.3 | 62.0 | 5.7 | 10.2% |
| CRP | 32.0 | 32.0 | 0.0 | 0% |
| Developed Land | 35.0 | 35.0 | 0.0 | 0% |

### 5.1.5.5 Fertilizer Use

As crop acres increase to meet the additional demand for corn and other crops for biofuel production, fertilizer use increases as a result. In addition, the harvesting of corn stover and other crop residues used to make cellulosic renewable fuel removes nutrients from the soil and requires greater fertilizer application. In 2022, FASOM estimates that nitrogen fertilizer use in the U.S. agricultural sector will increase by 1.5 billion pounds (5.7%) relative to the AEO2007 Reference Case levels. FASOM also projects that phosphorous fertilizer use will increase by 714 million pounds (12.7%) relative to the Reference Case level in 2022. The FAPRI-CARD model does not provide estimates for fertilizer use.

### Table 5.1-9.
### Change in U.S. Fertilizer Use Relative to the Reference Case (millions of pounds)

| Fertilizer | AEO 2007 Reference Case | Control Case | Change | %Change |
|---|---|---|---|---|
| Nitrogen | 26,209 | 27,710 | 1,501 | 5.7% |
| Phosphorous | 5,614 | 6,328 | 714 | 12.7% |

### 5.1.5.6 Impact on U.S. Farm Income

The increase in renewable fuel production provides a significant increase in net farm income to the U.S. agricultural sector. FASOM predicts that net U.S. farm income will increase by $13 billion dollars in 2022 (36 percent).

### 5.1.5.7 Impact on U.S. Food Prices

Higher corn and soybean prices also result in higher meat prices, although the increased production of coproducts that can be used as animal feed (e.g., DGS) that accompanies expanded biofuels production tends to limit price effects. For example, in 2022, the average price for all meat production in the FASOM model increases by 0.1 percent. In FAPRI-CARD, the price of beef increases by $0.37 per hundredweight (0.4 percent) in 2022 to $95.84 per hundredweight in the Control Case, and the price of pork increases by $0.77 per hundredweight (1.6 percent) in 2022 to $49.19 per hundredweight in the Control Case.

Due to higher commodity prices, FASOM estimates that U.S. food costs[YYYYYYYYYYY] would increase by roughly $10 per person per year by 2022, relative to the Reference Case.[ZZZZZZZZZZZ] Total effective farm gate food costs would increase by $3.6 billion (0.2 percent) in 2022.[AAAAAAAAAAAA] To put these changes in perspective, average U.S. per capita food expenditures in 2007 were $3,778 or approximately 10 percent of personal disposable income. The total amount spent on food in the U.S. in 2007 was $1.14 trillion dollars.[BBBBBBBBBBBB]

## 5.1.6 International Impacts

The FAPRI-CARD models are utilized to assess the international impacts on trade, land use, and food consumption as a result of the RFS2 renewable fuel volume requirement in the U.S. In the FAPRI-CARD models, links between the U.S. and international models are made through commodity prices and net trade equations. In general, for each commodity sector, the economic relationship that quantity supplied equals quantity demanded is achieved through a market-clearing price for the commodity. In non-U.S. countries, domestic prices are modeled as a function of the world price using a price transmission equation. Since econometric models for each sector can be linked, changes in one commodity sector will impact the other sectors.

The model for each commodity considers a number of specific countries/regions, and then includes a rest-of-the-world aggregate to close the model. The models specify behavioral equations for production, use, stocks, and trade between countries/regions. The models solve for

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[YYYYYYYYYYY] FASOM does not calculate changes in price to the consumer directly. The proxy for aggregate food price change is an indexed value of all food prices at the farm gate. It should be noted, however, that according to USDA, approximately 80% of consumer food expenditures are a result of handling after it leaves the farm (e.g., processing, packaging, storage, marketing, and distribution). These costs consist of a complex set of variables, and do not necessarily change in proportion to an increase in farm gate costs. In fact, these intermediate steps can absorb price increases to some extent, suggesting that only a portion of farm gate price changes are typically reflected at the retail level. See http://www.ers.usda.gov/publications/foodreview/septdec00/FRsept00e.pdf.

[ZZZZZZZZZZZ] These estimates are based on U.S. Census population projections of 331 million people in 2017 and 348 million people in 2022. See http://www.census.gov/population/www/projections/summarytables.html

[AAAAAAAAAAAA] Farm Gate food prices refer to the prices that farmers are paid for their commodities.

[BBBBBBBBBBBB] See www.ers.usda.gov/Briefing/CPIFoodAndExpenditures/Data/table15.htm.

representative world prices by equating excess supply and demand across countries. Using price transmission equations, the domestic price for each country is linked with the representative world price through exchange rates. It is through changes in world prices that change in worldwide commodity production and trade is determined.

### 5.1.6.1 Global Commodity Price Changes

As demand for renewable fuels in the U.S. increases, the FAPRI-CARD model projects that U.S. and world commodity prices will generally increase. FAPRI-CARD projects that the world price of corn increases by $0.12/bu (3.1 percent) relative to the AEO2007 Reference Case in 2022. Similarly, FAPRI-CARD projects that world soybean prices increase by $0.08/bu (0.8 percent) and the world soybean oil price increases by $13.22 per ton (1.5 percent) in 2022 relative to the AEO2007 Reference Case.

Since increased biofuel demand in the U.S. also impacts the livestock market, in terms of land use (i.e., pasture) and the feed market, we expect prices to change as well. The world price for beef, which is based on U.S. prices, increases $7.34 per ton (0.4 percent) in 2022 to $1,917 per ton in the Control Case.

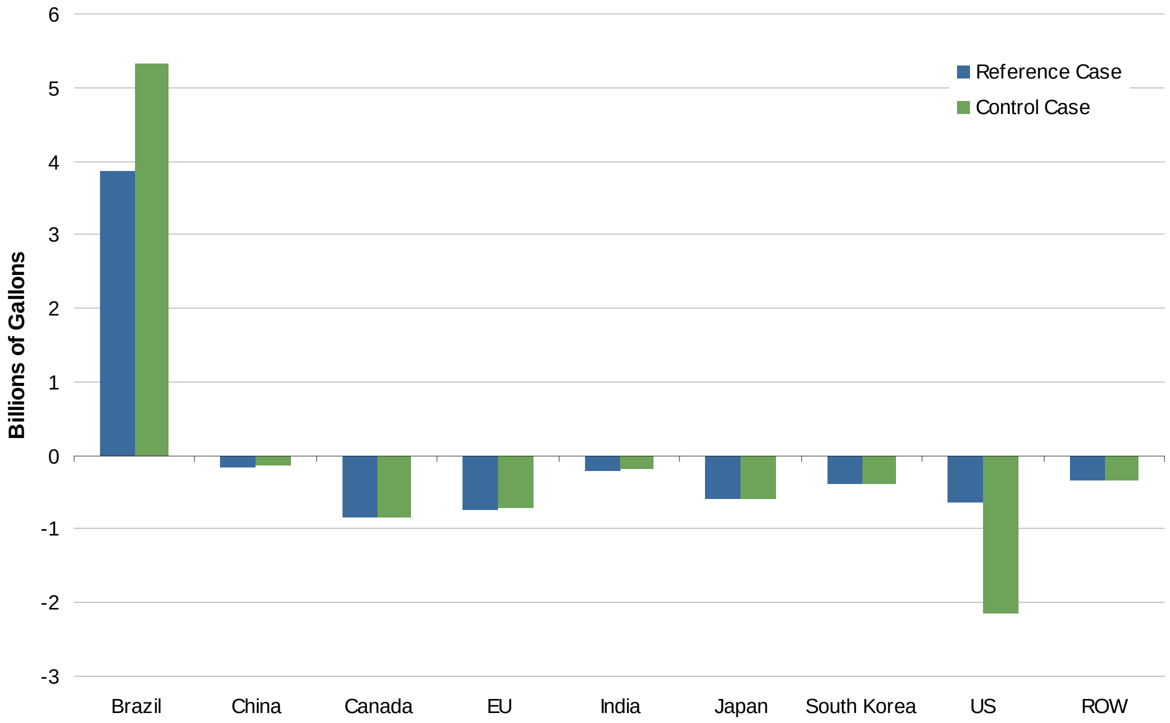
**Table 5.1-10.**
**Global Commodity Price**
**Changes from RFS2 in 2022**
**(2007$ per unit)**

| Commodity (Unit) | AEO 2007 Reference Case | Control Case | Change | % Change |
|---|---|---|---|---|
| Corn (bushel) | $3.76 | $3.88 | $0.12 | 3.1% |
| Soybeans (bushel) | $9.55 | $9.63 | $0.08 | 0.8% |
| Soybean Oil (ton) | $854.45 | $867.67 | $13.22 | 1.5% |
| Beef (ton) | $1,909.42 | $1,916.76 | $7.34 | 0.4% |

### 5.1.6.2 World Renewable Fuels Trade

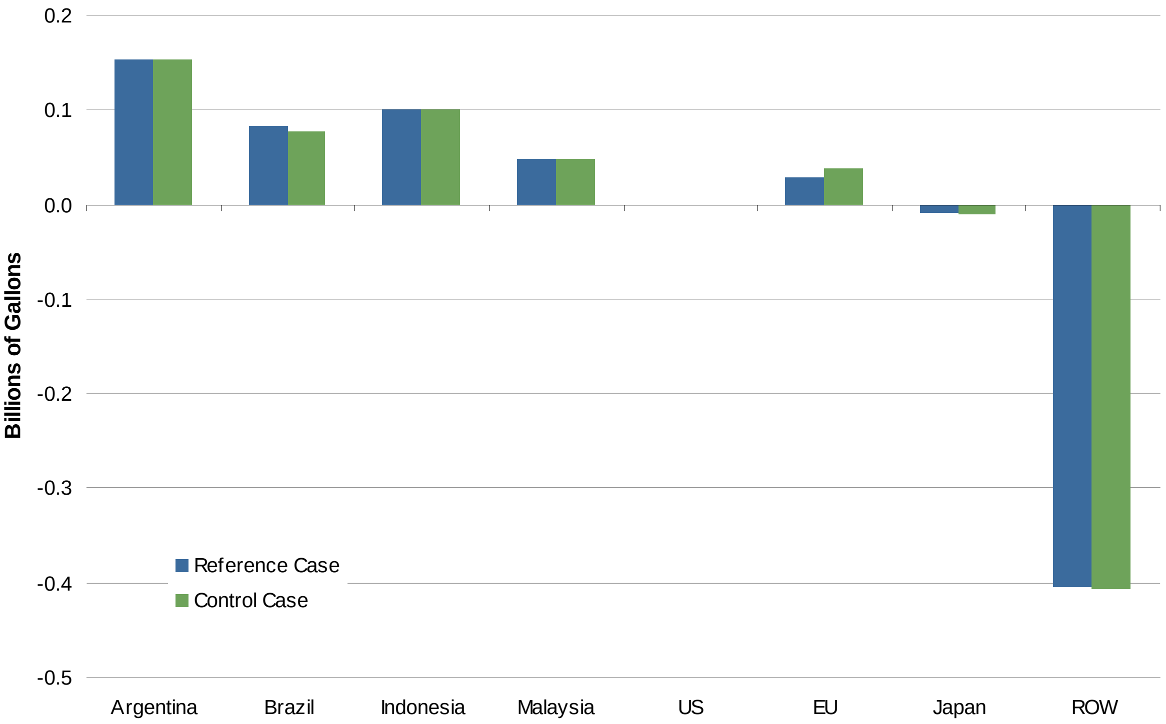
As the U.S. increases its demand for renewable fuels, world trade markets for renewable fuels are also likely to be impacted. As described in Section 1.2, we estimate that in 2022, the U.S. will increase net imports of ethanol by 1.6 billion gallons (248%) relative to the AEO2007 Reference Case. In response, FAPRI-CARD projects that Brazil will increase net exports by 1.5 billion gallons (37.8 percent) in 2022 relative to the Reference Case. However, since the U.S. demand for ethanol imports exceeds the increase in Brazilian net exports, FAPRI-CARD projects that other countries will reduce their net imports of ethanol. In 2022, FAPRI-CARD projects that China decreases net imports of ethanol by 7.9 million gallons (-5.3 percent), the European Union decreases net imports by 16.8 million gallons (-2.3 percent), India decreases net imports by 15.2 million gallons (-7.4 percent), Japan decreases net imports by 3.1 million gallons (-0.5 percent), and South Korea decreases net imports by 1.6 million gallons (-0.4 percent) relative to the AEO2007 Reference Case. The rest of the world decreases net imports of ethanol by 0.7 million gallons (-0.2 percent) in 2022 relative to the Reference Case.

**Figure 5.1-5.**
**Ethanol Net Exports by Country in 2022**



Since the world price of soybean oil increases (1.5 percent), whereas the world price of biodiesel decreases (-1.3 percent) due to the RFS2 renewable fuel volume requirements, it becomes relatively more profitable to increase net exports of soybean oil for major producers. This results in less soybean oil being used in the production of biodiesel and therefore a decrease in biodiesel net exports in some countries. Argentina decreases their biodiesel net exports by 1.3 million gallons (-0.8 percent) to 152.4 million gallons, Brazil decreases their biodiesel net exports by 6.2 million gallons (-7.4 percent) to 77.4 million gallons in 2022. In response the EU increases their net exports of biodiesel by 8.6 million gallons (29.6 percent) to 37.8 million gallons in the Control Case. Additionally, Japan reduces its net imports of biodiesel by 0.5 million gallons (-5.9 percent).

**Figure 5.1-6.**
**Biodiesel Net Exports by Country in 2022**

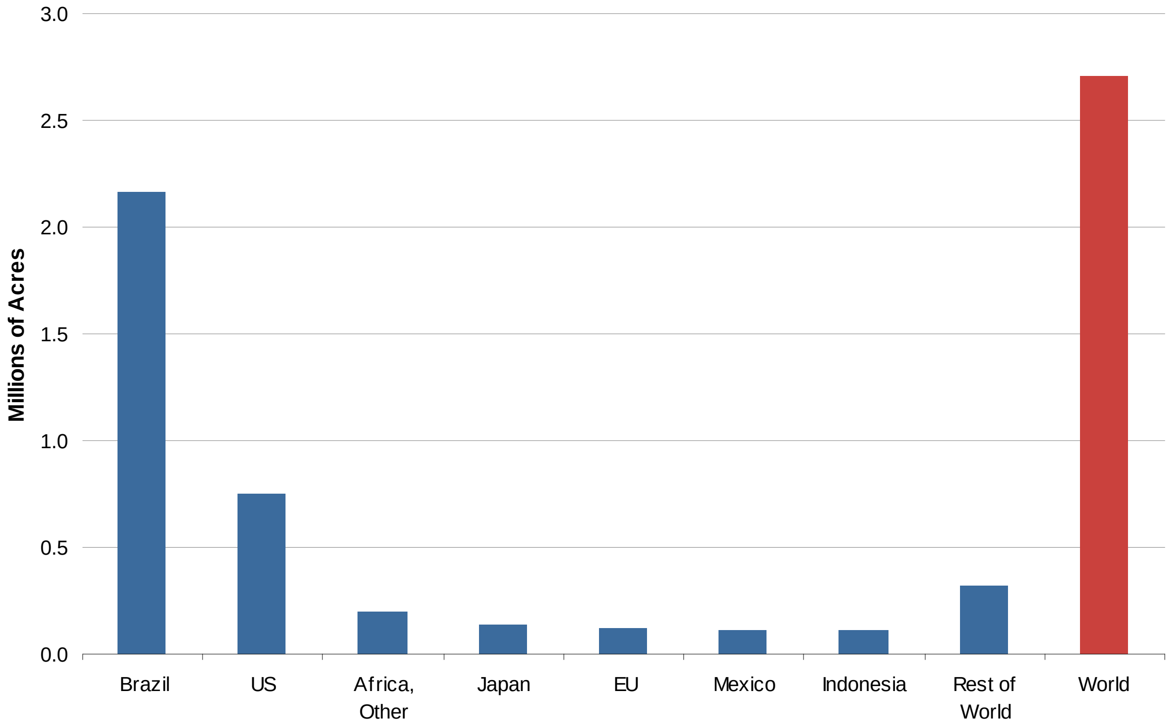


### 5.1.6.3 International Crop Acre Changes

Changes to the global commodity trade markets and world commodity prices result in changes in international land use. The FAPRI-CARD model provides international change in crop acres as a result of the RFS2 renewable fuel volumes. Internationally, Brazil has the largest increase in crop acres in 2022, followed by a subset of nations in Africa, Japan, the EU, Mexico, and Indonesia. As the U.S. increases its net imports of ethanol by 1.5 billion gallons in 2022, the major supplier of this increase in ethanol is Brazil which produces ethanol from sugarcane. The FAPRI-CARD model estimates that Brazil crop acres increase by 2.2 million acres (1.6 percent) relative to the AEO2007 Reference Case. The major crop contributing to this increase is sugarcane, which increases by 1.2 million acres (4.4 percent) in 2022. “Africa, Other” increases total crop acres by 0.20 million acres (0.25 percent), the large majority of which is corn, which increases by 0.19 million acres (0.32 percent). Japan increases its total crop acres by 0.14 million acres (3.3 percent), solely due to a 0.14 million acre increase in rice acres. The EU increases its crop acres as well, by 0.12 million acres (0.1 percent). This is a result of a 0.06 million acre increase in wheat (0.1 percent), a 0.04 million acre increase in barley (0.1 percent), and a 0.02 million acre increase in corn (0.1 percent). Mexico increases its crop acres by 0.11 million acres in 2022 (0.4 percent), which is primarily due to a 0.14 million acre increase in corn (0.6 percent) and small decreases in other crops. Indonesia increases its total crop acres by 0.11

million acres in 2022 (0.2 percent), including a 0.09 million acre increase in corn (0.9 percent) and a 0.02 million acre increase in rice (0.1 percent).

**Figure 5.1-7.**
**Change in World Crop Acres from the RFS2 Rule by Country in 2022**



In response to the increased U.S. demand for imported ethanol, which FAPRI-CARD estimates will be satisfied by increases in Brazil exports of sugarcane ethanol, sugarcane acres increase in various regions in Brazil. For instance, FAPRI-CARD projects 2022 sugarcane acres will increase by 0.01 million acres (2.7 percent) in the Amazon Biome region, 0.13 million acres (3.8 percent) in the Central-West Cerrados region, 0.15 million acres (3.6 percent) in the Northeast Coast region, 0.02 million acres (2.7 percent) in the North-Northeast Cerrados region, 0.05 million acres (2.5 percent) in the South region, and 0.87 million acres (5.0 percent) in the Southeast region, relative to the AEO2007 Reference Case.

Area for other crops in Brazil, including corn and soybeans, are affected not only by the increase in sugarcane crop acres, but also by the changes in world price for each commodity. Overall, total crop area in Brazil increases by 2.2 million acres (1.6 percent) in 2022 relative to the AEO2007 Reference Case. This change is includes an increase of 0.2 million acres (1.8 percent) in the Amazon Biome, an increase of 0.6 million acres (1.9 percent) in the Central-West Cerrados, an increase of 0.2 million acres (2.1 percent) in the Northeast Coast, an increase of 0.2 million acres (1.6 percent) in the North-Northeast Cerrados, an increase of 0.2 million acres (0.4

percent) in the South, and an increase of 0.7 million acres (2.6 percent) in the Southeast, relative to the AEO2007 Reference Case in 2022.

**Table 5.1-11.**
**Change in Brazil Sugarcane Acres and Total Crop Area from the RFS2 Rule by Region in 2022**
**(millions of acres)**

| Region | Sugarcane | | | | Total Crops | | | |
|---|---|---|---|---|---|---|---|---|
| | AEO 2007 Reference Case | Control Case | Change | % Change | AEO 2007 Reference Case | Control Case | Change | % Change |
| Amazon Biome | 0.45 | 0.46 | 0.01 | 2.7% | 12.0 | 12.2 | 0.2 | 1.8% |
| Central-West Cerrados | 3.38 | 3.51 | 0.13 | 3.8% | 31.8 | 32.4 | 0.6 | 1.9% |
| Northeast Coast | 4.07 | 4.21 | 0.15 | 3.6% | 11.1 | 11.3 | 0.2 | 2.1% |
| North-Northeast Cerrados | 0.64 | 0.66 | 0.02 | 2.7% | 14.6 | 14.8 | 0.2 | 1.6% |
| South | 2.02 | 2.07 | 0.05 | 2.5% | 39.9 | 40.1 | 0.2 | 0.4% |
| Southeast | 17.47 | 18.34 | 0.87 | 5.0% | 26.3 | 27.0 | 0.7 | 2.6% |
| Brazil, Total | 28.04 | 29.27 | 1.23 | 4.4% | 135.7 | 137.9 | 2.2 | 1.6% |

### 5.1.6.4 World Food Markets

The increase in renewable fuel volumes associated with the RFS2 will also impact world food consumption patterns.[cccccccccccc] Since major agricultural commodity prices increase globally, FAPRI-CARD projects that world consumption of food decreases by 2.5 million metric tons (-0.1 percent) in 2022, relative to the AEO2007 Reference Case. This change is includes a decrease of consumption of dairy food products of 0.1 million metric tons (-0.03 percent), a decrease of 0.1 million metric tons (-0.05 percent) of livestock, a decrease of 0.3 million metric tons (-0.15 percent) of sugar, a decrease of 0.4 million metric tons (-0.12 percent) of grains, a decrease of 1.7 million metric tons (-4.5 percent) of vegetable oils, and an increase of 0.1 million metric tons (0.03 percent) of rice, relative to the AEO2007 Reference Case in 2022. Wheat consumption levels do not change between the Reference Case and the Control Case. While FAPRI-CARD provides estimates of changes in world food consumption, estimating effects on global nutrition is beyond the scope of this analysis.

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[cccccccccccc] The food commodities included in the FAPRI model include corn, wheat, sorghum, barley, soybeans, sugar, peanuts, oils, beef, pork, poultry, and dairy products.

**Table 5.1-12.**
**Change in World Food Consumption Relative to the Reference Case**
**(millions of metric tons)**

| Category | AEO 2007 Reference Case | Control Case | Change | % Change |
|---|---|---|---|---|
| Dairy | 288.2 | 288.1 | -0.1 | -0.03% |
| Livestock | 301.4 | 301.3 | -0.1 | -0.05% |
| Sugar | 206.3 | 206.0 | -0.3 | -0.15% |
| Wheat | 605.9 | 605.9 | 0.0 | 0.00% |
| Grains | 314.5 | 314.1 | -0.4 | -0.12% |
| Vegetable Oils | 37.1 | 35.4 | -1.7 | -4.5% |
| Rice | 500.6 | 500.7 | 0.1 | 0.03% |
| Total Food | 2,258.4 | 2,256.0 | -2.5 | -0.1% |

## 5.2 Petroleum, Renewable Fuels and Energy Security Impacts

Increasing usage of renewable fuels helps to reduce U.S. petroleum imports. A reduction of U.S. petroleum consumption and imports reduces both financial and strategic risks associated with a potential disruption in supply or a spike in cost of a particular energy source. This reduction in risks is a measure of improved U.S. energy security. In this section, we detail an updated methodology for estimating the energy security benefits of reduced U.S. oil imports which explicitly includes renewable fuels. Based upon this updated approach, we estimate the monetary value of the energy security benefits associated with the increased usage of renewable fuels in the U.S. required by the RFS2 rule.

### 5.2.1 Implications of Reduced Petroleum Use on U.S. Imports

In 2008, U.S. petroleum import expenditures represented 21 percent of total U.S. imports of all goods and services.[DDDDDDDDDDDD] In 2008, the U.S. imported 66 percent of the petroleum it consumed, and the transportation sector accounted for 70 percent of total U.S. petroleum consumption. This compares to approximately 37 percent of petroleum from imports and 55 percent consumption of petroleum in the transportation sector in 1975.[EEEEEEEEEEEE] It is clear that petroleum imports have a significant impact on the U.S. economy. Requiring the wider use of renewable fuels in the U.S. is expected to lower U.S. petroleum imports.

For this rule, EPA estimated the reductions in U.S. petroleum imports using a modified version of the National Energy Modeling System (EPA-NEMS). EPA-NEMS is an energy-economy modeling system of U.S. energy markets through the 2030 time period. EPA-NEMS projects U.S. production, imports, conversion, consumption, and prices of energy subject to

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[DDDDDDDDDDDD] Source: U.S. Bureau of Economic Analysis, U.S. International Transactions Accounts Data, as shown on June 24, 2009.

[EEEEEEEEEEEE] Source: U.S. Department of Energy, Annual Energy Review 2008, Report No. DOE/EIA-0384(2008), Tables 5.1 and 5.13c, June 26, 2009.

assumptions on world energy markets, resource availability and costs, behavioral and technological choice criteria, cost and performance characteristics of energy technologies, and demographics. For this analysis, the 2009 NEMS model was modified to use the 2007 (pre-EISA) Annual Energy Outlook (AEO) levels of renewable fuels in the Reference Case. These results were compared to our Control Case, which assumes the renewable fuel volumes required by EISA will be met by 2022. Details on how the EPA-NEMS model was adjusted to incorporate these volumes are included in the docket.[FFFFFFFFFFFF] The reduction in U.S. oil imports projected by EPA-NEMS is roughly 0.9 million barrels per day (a 9.5 per cent reduction in 2022). It is estimated that U.S. oil production in 2022 declines by much less, just 0.01 million barrels per day.

Using the EPA-NEMS model, we also calculated the change in expenditures in both U.S. petroleum and renewable fuel imports with the RFS2 rule and compared these with the U.S. trade position measured as U.S. net exports of all goods and services economy-wide. Changes in fuel expenditures were estimated by multiplying the changes in petroleum and renewable fuel net imports by the respective imported petroleum prices and wholesale ethanol price forecasts. In Table 5.2.1-1, the net expenditures in reduced petroleum imports and increased renewable fuel imports are compared to the total value of U.S. net exports of goods and services of the whole economy for 2022 as estimated by the EPA-NEMS model. We project that avoided expenditures on imported crude oil and petroleum products from the 2022 RFS2 volumes of renewable fuels would be roughly $41.5 billion. Taking into consideration imports of renewable fuels, the total avoided expenditures on imported transportation fuels are projected to be $37.2 billion in the RFS2 control case.

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[FFFFFFFFFFFF] See OnLocation, Inc. RFS2 Modeling Analysis Documentation, dated January 12, 2010.

**Table 5.2.1-1.**
**Selected U.S. Exports and Imports in 2022**
**(billions of 2007$)**

| Category | AEO 2007 Reference Case | RFS2 Control Case | Change | Percent Change |
|---|---|---|---|---|
| Total U.S. Exports of Goods and Services | 3,838 | 3831 | 7 | +0.22% |
| Total U.S. Imports of Goods and Services | 3,840 | 3833 | 7 | +0.23% |
| Total U.S. Net Imports of Goods and Services | 2 | 2 | 0 | 0% |
| Expenditures on Net Petroleum Imports | 456 | 414 | -41.5 | -9.1%[GGGGGGGGGGGG] |
| Expenditures on Imported Ethanol | 1 | 5.3 | +4.3 | +419% |
| Total Expenditures on Transportation Fuel Imports | 457 | 420 | -37.2 | -8.1% |

### 5.2.2 Background on U.S. Energy Security

U.S. energy security is broadly defined as protecting the U.S. economy against circumstances that threaten significant short- and long-term increases in energy costs. Most discussion of U.S. energy security revolves around the topic of the economic costs of U.S. dependence on oil imports, although energy security is also a function of the stability of overall fuel supply and the flexibility of demand. An important part of the problem stems from U.S. reliance on imported oil, and the global oil market is strongly influenced by potentially unfriendly and unstable sources. In addition, oil exporters have the ability to raise the price of oil by exerting monopoly power through the formation of a cartel, the Organization of Petroleum Exporting Countries (OPEC). Finally, these factors contribute to the vulnerability of the U.S. economy to episodic oil supply shocks and price spikes. In 2008, U.S. imports of crude oil were roughly $391 billion (2007$, see Figure 5.2.2-1).

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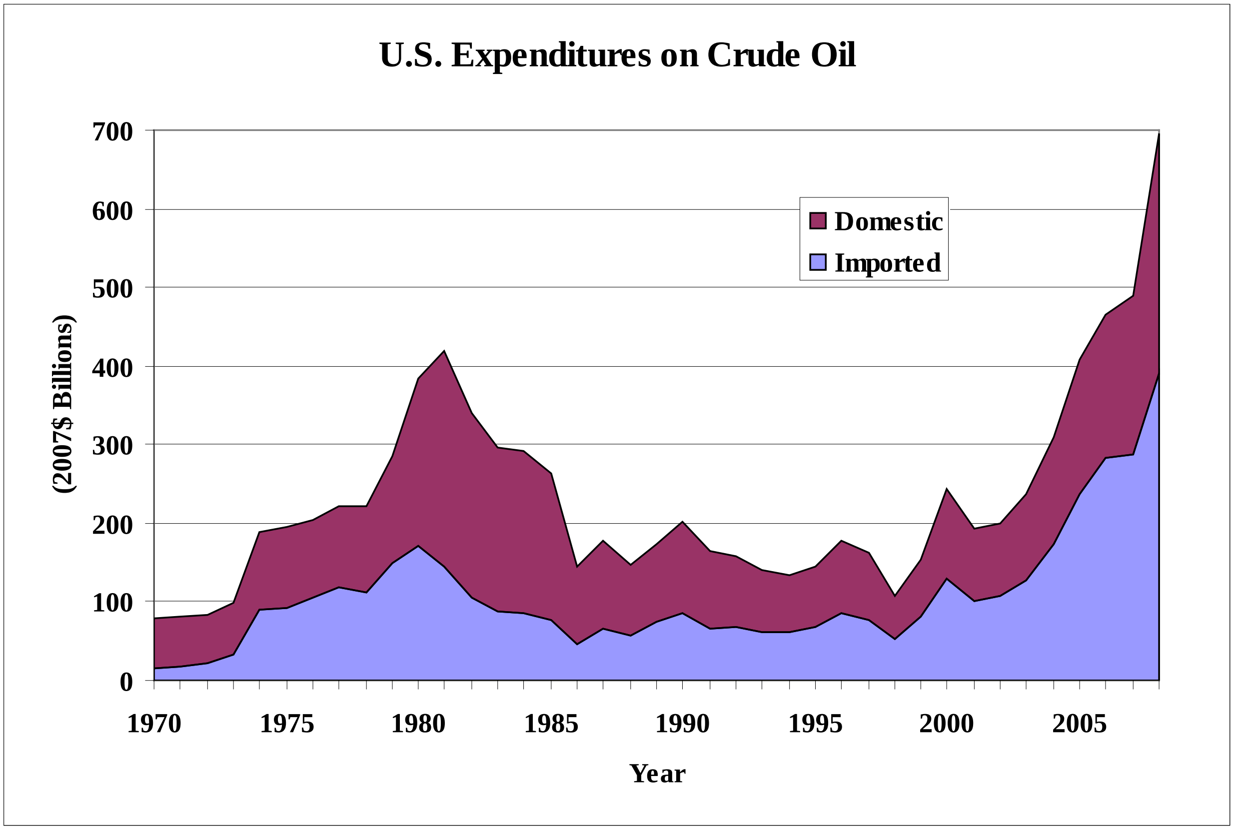
[GGGGGGGGGGGG] Note: the 9.1 per cent reduction included in this table is a change in the monetary value of the oil reductions, whereas the 9.5 per cent reduction in oil imports cited in the previous paragraph refers to the volumetric change in imports.

**Figure 5.2.2-1. U.S. Expenditures on Crude Oil**



Source: Annual Energy Reviews and AEO 2009.

By requiring the wider use of renewable fuels, the RFS2 rule promotes diversification of transportation fuels in the U.S. and helps to improve the U.S.'s energy security. For the RFS2 proposal, an "oil import premium" approach was utilized to identify those energy security-related impacts which are not reflected in the market price of oil, and which are expected to change in response to an incremental change in the level of U.S. oil imports. For this analysis, the "oil import premium" approach was extended to explicitly consider the energy security implications of the expansion of renewable fuels required by the RFS2 rule.

### 5.2.3 Methodology Used to Estimate U.S. Energy Security Benefits

In order to understand the energy security implications of reducing U.S. oil imports, EPA has worked with Oak Ridge National Laboratory (ORNL), which has developed approaches for evaluating the social costs and energy security implications of oil use. In a recent study entitled "*The Energy Security Benefits of Reduced Oil Use, 2006-2015*," completed in 2007 for the final RFS1 rulemaking, ORNL updated and applied the method used in the 1997 report "*Oil Imports: An Assessment of Benefits and Costs*", by Leiby, Jones, Curlee and Lee.[HHHHHHHHHHHH,IIIIIIIIIIII]

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[HHHHHHHHHHHH] Leiby, Paul N., Donald W. Jones, T. Randall Curlee, and Russell Lee, *Oil Imports: An Assessment of Benefits and Costs*, ORNL-6851, Oak Ridge National Laboratory, November, 1997.

The updated 2007 report was included as part of the record in the final RFS1 rulemaking, and revisions were made based on external comment and peer review. [JJJJJJJJJJJJ,KKKKKKKKKKKK]

Significant factors that drive energy security costs have been changing over the last decade, including: projected world oil prices, current and anticipated levels of OPEC production, U.S. oil import levels, the estimated responsiveness of regional oil supplies and demands to price, and the likelihood of oil supply disruptions. For this analysis, oil prices and supply and demand energy balances from the EIA's AEO 2009 Reference Case were used. In many instances, the recent market trends and projections suggest reasons for greater concern about oil security costs, compared to the prior decade: higher oil prices; growing U.S. import levels; and a larger value-share of oil in GDP. To the extent that the U.S. economy has become more resilient, and less sensitive to oil shocks, or that improved macroeconomic policies have reduced the impact of oil shocks, there may be influences countervailing to the oil market trends. This possibility is considered in the security estimates, but recent macroeconomic disturbances indicate that greater future macroeconomic stability cannot be assured. The degree to which sharply higher oil prices contributed to, or exacerbated, the recent global recession has not yet been resolved.[LLLLLLLLLLLL]

In order to understand the energy security implications of this rule, EPA used the Oil Security Metrics Model[MMMMMMMMMMMM,NNNNNNNNNNNN,OOOOOOOOOOOO] (OSMM), developed and maintained by Oak Ridge National Laboratory. The OSMM estimates the U.S. energy security benefits from increased availability and use of renewable transportation fuels. The OSMM took

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[IIIIIIIIIIII] The 1997 ORNL paper was cited and its results used in DOT/NHTSA's rules establishing CAFE standards for 2008 through 2011 model year light trucks. See DOT/NHTSA, Final Regulatory Impacts Analysis: Corporate Average Fuel Economy and CAFE Reform MY 2008-2011, March 2006.

[JJJJJJJJJJJJ] Leiby, Paul N. "*Estimating the Energy Security Benefits of Reduced U.S. Oil Imports: Final Report*", ORNL/TM-2007/028, Oak Ridge National Laboratory, March, 2008.

[KKKKKKKKKKKK] Updating the ORNL methodology to incorporate the comments from the Peer Reviewers, based on AEO2007, ORNL estimated that the total energy security benefits associated with a reduction of imported oil is $12.38/barrel, with a range of $6.88 - $18.52/barrel of imported oil reduced ($2006). When the same methods and assumptions are applied to the AOE2009 Reference outlook, comparable estimates for 2025 are $19.21/barrel, with a range of $10.8 to $29.6/barrel.

[LLLLLLLLLLLL] See Hamilton, J. D. 2009, "*Causes and Consequences of the Oil Shock of 2007-08*", Brookings Papers on Economic Activity, 2009, or the congressional testimony of Yergin, D. "*The Long Aftershock: Oil: Oil and Energy Security After the Price Collapse*" Testimony to U.S. Congress, Hearings, Joint Economic Committee, Oil and the Economy: The Impact of Rising Global Demand on the U.S. Recovery. May 20, 2009.

[MMMMMMMMMMMM] The OSMM methods are consistent with the recommended methodologies of the National Resource Council's (NRC's) (2005) Committee on Prospective Benefits of DOE's Energy Efficiency and Fossil Energy R&D Programs. The OSMM defines and implements a method that makes use of the NRC's typology of prospective benefits and methodological framework, satisfies the NRC's criteria for prospective benefits evaluation, and permits measurement of prospective energy security benefits for policies and technologies related to oil. It has been used to estimate the prospective oil security benefits of Department of Energy's Energy Efficiency and Renewable Energy R&D programs, and is also applicable to other strategies and policies aimed at changing the level and composition of U.S. petroleum demand. To evaluate the RFS2, the OSMM was modified to include supplies and demand of biofuels as well as petroleum.

[NNNNNNNNNNNN] Greene D.L. and P.N. Leiby, 2006. *The Oil Security Metrics Model: A Tool for Evaluating the Prospective Oil Security Benefits of DOE's Energy Efficiency and Renewable Energy R&D Programs*, ORNL/TM-2006/505, Oak Ridge National Laboratory (ORNL), 2006.

[OOOOOOOOOOOO] Leiby, P.N., *Energy Security Impacts of Renewable Fuel Use Under the RFS2 Rule – Methodology*, Oak Ridge National Laboratory, January 19, 2010.

as inputs the renewable fuel volumes that are required under EISA as well at the renewable fuel costs estimated in Chapter 4.4 of this RIA. In addition, it assumed EPA's projections of flexible fueled vehicles and use of E85. In conducting this analysis, ORNL considered the full economic cost of importing petroleum into the U.S. The full economic cost of importing petroleum into the U.S. is defined for this analysis to include two components in addition to the purchase price of petroleum itself. These are: (1) the higher costs for oil imports resulting from the effect of U.S. import demand on the world oil price and OPEC market power (i.e., the "import demand" or "monopsony" costs); and (2) the risk of reductions in U.S. economic output and disruption of the U.S. economy caused by sudden disruptions in the supply of imported oil to the U.S. (i.e., "macroeconomic disruption/adjustment costs"). Analogously, this analysis for the RFS2 rule also considers the economic costs of importing renewable fuels to meet the RFS2 rule requirements, and the estimated disruption/adjustment costs to the economy of renewable fuel price volatility due to renewable fuel supply disruptions (e.g., droughts and floods, etc.).

This energy security analysis extends the prior "oil import premium" analysis by considering risk-shifting that might occur as the U.S. reduces its dependency on petroleum by increasing its use of renewable fuels. The analysis accounts for the energy security implications associated with renewable fuels, such as possible supply disruptions of ethanol made from corn or ethanol derived from cellulosic feedstocks such as switchgrass. The use of OSMM broadens our energy security analysis to incorporate estimates of overall motor fuel supply and demand flexibility and reliability, and the impacts of possible agricultural sector market disruptions. For example, the use of renewable fuels can modestly alter short and long run demand elasticities (i.e., flexibility) in the motor fuel market, with implications for robustness of the fuel system in the face of diverse supply shocks.

As in the "oil import premium" analysis for the RFS2 proposal, U.S. military costs are excluded from the analysis performed by ORNL because their attribution to particular missions or activities is difficult. Most military forces serve a broad range of security and foreign policy objectives. Attempts to attribute some share of U.S. military costs to oil imports are further challenged by the need to estimate how those costs might vary with incremental variations in U.S. oil consumption and imports. Similarly, the Strategic Petroleum Reserve (SPR) size and policy is assumed unchanged by the RFS2 rule.

### 5.2.4 Effect of Oil Use on Long-Run Oil Price and U.S. Import Costs

The first component of the full economic costs of oil use in the U.S. follows from the effect of U.S. import demand on the world oil price over the long-run. Because the U.S. is a sufficiently large purchaser of foreign oil supplies, its purchases can affect the world oil price. This monopsony power means that increases in U.S. petroleum demand can cause the world price of crude oil to rise, and conversely, that reductions in U.S. petroleum demand can reduce the world price of crude oil. Thus, one benefit of decreasing U.S. oil purchases, due to the increased availability and use of other transportation fuels, is the potential decrease in the crude oil price paid for all crude oil purchased.

The demand or monopsony effect can be readily illustrated with an example. If the U.S. imports 10 million barrels per day at a world oil price of $50 per barrel, its total daily bill for oil imports is $500 million. If a decrease in U.S. imports to 9 million barrels per day causes the world oil price to drop to $49 per barrel, the daily U.S. oil import bill drops to $441 million (9 million barrels times $49 per barrel). While the world oil price only declines $1, the resulting decrease in oil purchase payments of $59 million per day ($500 million minus $441 million) is equivalent to an incremental benefit of $59 per barrel of oil imports reduced, or $10 more than the newly-decreased world price of $49 per barrel. This additional $10 per barrel "import cost premium" or "monopsony" benefit represents the incremental external benefit to U.S. society as a whole for avoided import costs beyond the price paid for oil purchases. This additional benefit arises only to the extent that the reduction in U.S. oil imports affects the world oil price.

A similar rationale can be applied to estimate the monopsony disbenefits of the increased use of renewable fuels from the RFS2 rule. In the same way, but working in the opposite direction of the oil market, increased use of renewable fuels in the U.S. is expected to increase demand for domestic and imported renewable fuels, and to increase the world price of renewable fuels. This results in higher total costs of U.S. renewable fuel imports. While the total cost of renewable fuel imports under a policy like RFS2 rule will include the cost of the additional imports, the monopsony cost portion is the added amount paid for the imports that would have occurred without the RFS2 rule renewable fuel volumes. Thus, to look at the total monopsony impacts of the RFS2 rule renewable fuel volumes, two separate impacts need to be assessed. First, U.S. oil import reductions result in paying lower prices for all barrels of U.S. imported oil, providing monopsony benefits. Second, increased use of renewable fuels results in higher prices of U.S. imported renewable fuels, yielding monopsony disbenefits for renewable fuels. The total monopsony benefit is the combined sum of these separate market impacts.

Table 5.2.4.1 shows the RFS2 Reference Case levels of U.S. oil and renewable fuel imports as well as the average change in oil prices and renewable fuel prices projected due to the RFS2 volumes in 2022. The Reference Case renewable fuel imports are relatively modest compared to oil (roughly 0.015 billions of barrels of renewable fuel are imported versus 3.283 billion barrels of oil). Projected U.S. renewable fuel imports in 2022 are ethanol, principally made from sugar cane harvested in Brazil. In 2022, the estimated change in ethanol price due to the RFS2 renewable fuel volumes is $0.61/barrel, and the estimated reduction in the world oil price is $1.05/barrel. The monopsony effect is the change in costs of the quantities of fuel imported without the RFS2 renewable fuel volumes (i.e., the Reference Case fuel volumes). Since the change in the renewable fuel price applies to a much smaller quantity of renewable fuel imports than U.S. oil imports, the monopsony disbenefit per barrel of increased renewable fuel use is much smaller, only $0.02/barrel, compared to the oil monopsony benefit, $7.88/barrel. Thus, including the impact of expanded renewable fuel use on renewable fuel imports and price yields a slightly lower estimate of the total monopsony benefits.

### Table 5.2.4-1.
### Determinates of Monopsony Benefits of the RFS2 Renewable Fuel Volumes vs. AEO2007 Reference Case

| Fuel | Reference Case Import Quantity (billions of barrels in 2022) | Change in Price ($ per barrel in 2022) | Monopsony Benefit ($ billion in 2022) | Monopsony Benefit ($/barrel of renewable fuel) in 2022) |
|---|---|---|---|---|
| Renewable Fuels | 0.015 | 0.61 | -0.009 | -0.02 |
| Oil | 3.282 | -1.06 | 3.476 | 7.88 |
| Total | | | | 7.86 |

This analysis of the import cost and monopsony effect is based on the net import levels of petroleum as projected by the EPA-NEMS, and is not sensitive to the mix of crude and product imports. It is possible that in the future, while the U.S. will import most of its crude oil and some petroleum products, it may be a net exporter of others, e.g. diesel fuel.[pppppppppppp] However, oil security concerns stem from the total consumption and net import of all petroleum fuels, whose prices are all directly dependent on the volatile (and non-competitive) world crude oil market. For this analysis, the key issue is not the trade balance for particular petroleum products, but the net level of U.S. consumption and import of all petroleum, both crude and products. Reducing domestic gasoline or diesel fuel with renewable fuels use can reduce net imports of all petroleum, and net import costs, even if the U.S. remains a net exporter of some petroleum products. Consider the case of U.S. diesel fuel. Replacing U.S. diesel fuel consumption with renewable biodiesel, whose root supply volatility is largely independent of that of petroleum, can reduce the volatility of productive inputs to the macroeconomy, regardless of the trade balance in diesel fuel.

### 5.2.5 Macroeconomic Dislocation Costs Associated with Oil and Renewable Fuel Price Variability

Fluctuations in oil and renewable fuel prices are estimated to cause macroeconomic losses due to dislocations and adjustment costs. Macroeconomic losses during price shocks reflect both aggregate output losses and so called “allocative” losses. The former are a reduction in the level of output that the U.S. economy can produce fully using its available resources; and the latter stem from temporary dislocation and underutilization of available resources due to the shock, such as labor unemployment and idle plant capacity. The aggregate output effect, a reduction in “potential” economic output, will last so long as the price is elevated. It depends on the extent and duration of any disruption in the world supply of oil, since these factors determine

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[pppppppppppp] While at the time of the implementation of this rule, the U.S. exports some diesel fuel, it is not clear that this situation will long persist. Under EIA AEO2009, the U.S. is a net importer of refined products (as well as crude) throughout the forecast horizon. In particular, over the RFS2 horizon (2010-2022) diesel fuel consumption is expected to grow at 1.4 per cent per year (Table 11) while gasoline demand will decline at 1.0 per cent per year. Thus, under this outlook, crude refinery runs needed to meet gasoline supply will decline, while U.S. demand for the distillate/diesel cuts will grow.

the magnitude of the resulting increase in prices for petroleum products, as well as whether and how rapidly these prices return to their pre-disruption levels.

In addition to the aggregate contraction, there are “allocative” or “adjustment” costs associated with dislocated energy markets. Because supply disruptions and resulting price increases occur suddenly, empirical evidence shows they impose additional costs on businesses and households which must seek to adjust their use of petroleum and other productive factors more rapidly than if the same price increase had occurred gradually. Opportunities for short run adjustments of energy use and other productive factors of the economy are limited and costly. Dislocational effects include the unemployment of workers and other resources during the time needed for their intersectoral or interregional reallocation, and pauses in capital investment due to uncertainty. These adjustments temporarily reduce the level of economic output that can be achieved even below the “potential” output level that would ultimately be reached once the economy’s adaptation to higher petroleum prices was complete. The additional costs imposed on businesses and households for making these adjustments reflect their limited ability to adjust prices, output levels, and their use of energy, labor and other inputs quickly and smoothly in response to rapid changes in prices for petroleum products.

In the prior “oil import premium” analysis undertaken for the RFS2 proposal, oil price shocks were estimated to have macroeconomic losses based on a single fixed elasticity of Gross Domestic Product (GDP) with respect to oil price. For this final RFS2 rule analysis in the OSMM, it is recognized that the dislocation portion of disruption costs depends not only on the magnitude of the price change, but on the changing importance of both oil and renewable fuels in the economy, as well as the degree to which the price movement is novel and disturbing.[QQQQQQQQQQQQ] Thus, when a shock causes fuel prices to jump up and stay up, initially the dislocation is larger, and over time the economy adjusts to higher prices and the macroeconomic dislocation dissipates. To account for this, OSMM tracks the evolution of an “adjusted” oil price and renewable fuel price, which is based on a lagged partial adjustment process, essentially yielding a weighted average of past prices with geometrically declining weights. This weighted-lag adjusted price is constructed to represent the average price level to which the economy has already had time to adjust.[RRRRRRRRRRRR] It is deviations from this level that are dislocational and costly. For both oil price and renewable fuel price fluctuations, the macroeconomic dislocation cost is calculated by applying a GDP loss elasticity to the ratio of the current price to the adjusted price. Furthermore, the applied GDP elasticity varies with the value share of expenditure on the fuel, both for oil and renewable fuels, in the economy. The estimated GDP losses from renewable fuel price fluctuations are based on a GDP Adjustment

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[QQQQQQQQQQQQ] This attention to the degree to which the observed price is unusual or “novel” follows the work of Lee et al. (Lee, K.; Ni, S. & Ratti, R. “*Oil shocks and the Macroeconomy: The Role of Price Variability*” *Energy Journal*, 1995, 16, 39-56, and Hamilton’s NOPI formulation (e.g. Hamilton, J. “*What is an Oil Shock*?”, *Journal of Econometrics*, Elsevier, 2003, 113, 363-398). Several works of Brown, Huntington, and Gately, for example, also consider the role of an “adjusted price” in the determination of supply and demand responses.

[RRRRRRRRRRRR] The adjusted price is the geometric distributed (i.e., Koyck) lag average of all prior prices, to represent that the economy only partially adjusts to changing prices each year. The annual adjustment rate of this price, which corresponds to the assumed annual accommodation of new prices by the macroeconomy, is taken as 33 per cent. This is consistent with empirical evidence that the dislocational impact of energy price shocks extends more than one year, but is mostly complete after three years.

Cost[ssssssssssss] elasticity with respect to oil prices, but rescaled in accordance with the ratio of renewable fuel expenditures to total oil expenditures.

One feature of the OSMM is its explicit treatment of renewable fuel volatility. Renewable fuel supply and hence, the price of renewable fuels, is also subject to disturbances, and the resulting production cost volatility is anticipated to impose some costs on the economy. While E85 and gasoline prices are often strongly correlated at the level of individual retail stations, this correlation reflects primarily the process of market substitution, and the expected phenomenon that ordinarily end-use prices for close substitutes will equilibrate and track one another. Further upstream (i.e., closer to the terminal and production plant gate), this price correlation diminishes. The historical prices of agricultural products that are likely to be used as feedstocks for renewable fuels are somewhat volatile, but almost completely uncorrelated with oil prices. For example, consider monthly price changes between crude oil and key agricultural crops that would be used as feedstocks for renewable fuels—sugar, corn, switchgrass, and softwood lumber—during the time period from January, 1990 to December, 2008 (Table 5.2.5-1 below). In the case considered here, wheat prices are used as a surrogate for switchgrass prices, since both crops are likely to be grown in similar agricultural areas in the U.S. (i.e., the Southwest region of the U.S.) and subject to similar weather patterns. These agricultural commodities have relatively low correlations with crude oil; 3 percent, 5 percent, -1 percent and 1 percent, for sugar, wheat, corn and softwood lumber, respectively.

**Table 5.2.5-1. Cross Correlations of Monthly Price Changes of Crude Oil and Selected Key Renewable Fuel Feedstocks, January, 1990 to December, 2008**

| | Crude Oil | Sugar | Wheat | Corn | Softwood |
|---|---|---|---|---|---|
| Crude Oil | 100% | 3% | 5% | -1% | 1% |
| Sugar | | 100% | 20% | 10% | 2% |
| Wheat | | | 100% | 46% | 23% |
| Corn | | | | 100% | -10% |
| Softwood | | | | | 100% |

Source: Leiby 2009, based on IMF/IFS database, Commodity Prices & Indices, Monthly, 1970 to December 2008.

From the standpoint of quantifying the macroeconomic/disruption of the increased use of renewable fuels, two factors are important. The first factor is an estimate of the variability in the supply of renewable fuels. The second factor is the change in renewable fuel production costs that stems from fundamental supply volatility at the feedstock level. This analysis represents renewable fuel supply volatility and risk based on historical variations in annual crop yields. Crop yields vary substantially from year to year based on growing conditions, including droughts

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[ssssssssssss] GDP Adjustment Costs from biofuel price fluctuations are based on applying the adjustment cost elasticity to the ratio of the current year price to the adjusted price. See Huntington (2005, "*The Economic Consequences of Higher Crude Oil Prices*," Final Report EMF SR 9, Energy Modeling Forum, Stanford University, October, p. 43) notes "Economic theory suggests strongly that, in the absence of major threshold effects, the direct response of the GDP and price levels to oil price changes should be proportional to oil's value share in total output." In the OSMM, for both oil and biofuels, the adjustment cost elasticity varies from year to year according to the expenditure share in GDP. For biofuels it is given by the 1983 reference value for oil times the ratio of current biofuel expenditure share to 1983 oil expenditure share.

and floods, and a variety of other factors.[TTTTTTTTTTTT] The supply risk of lower volumes of feedstock production due to a host of factors is assumed to be independent of oil prices.

Data on renewable fuel feedstock yield volatilities are presented in Table 5.2.5-2 below. Resulting estimates of renewable fuel cost volatility, based upon standard deviations from historical trends in renewable fuel feedstock yields, vary from 2.4 percent to 8.7 percent, with ethanol derived from sugar cane estimated to have the lowest volatility, and ethanol derived from corn estimated to have the highest volatility. These estimates of feedstock yield volatility are then used to estimate variations in feedstock cost[UUUUUUUUUUUU] and implied variations in renewable fuel production costs at the plant gate.[VVVVVVVVVVVV] As one would expect, renewable fuel cost volatility increases with the volatility of feedstock supply, but decreases in cases where feedstocks comprise a lower percentage of total production cost (as is the case with cellulosic renewable fuel). By way of comparison, the historical volatility of world oil prices over the last twenty-five years is 28 percent, considerably higher than the estimated volatility of renewable fuels.[WWWWWWWWWWWW]

**Table 5.2.5-2.**
**Selected Key Renewable Fuel Feedstocks Annual Yield Volatility**

| Renewable Fuel Feedstock | Corn | Soybeans | Wheat | Sugar Cane |
|---|---|---|---|---|
| Historical Yield Volatility | 8.69% | 6.81% | 13.07% | 2.37% |
| Based on Years | 1960-2008 | 1960-2008 | 1960-2008 | 1997-2008 |

Source: OSSM Supporting Data, Leiby/ORNL 2009. Volatility is measured as the standard deviation of annual percentage deviation from historical trend yields. Yield data and volatility are from Bruce Babcock, CARD, Iowa State, November, 2009.

The introduction of renewable fuels affects macroeconomic disruption costs from oil by reducing the oil-intensity of the economy, and by changing oil price movements slightly (since the addition of renewable fuels slightly alters the elasticity of demand for motor fuels). In addition, the introduction of renewable fuels affects the macroeconomic disruption costs by adding separate disruption costs associated with the independent volatility of renewable fuels supply. The magnitude of GDP dislocation losses for a given oil price change is calculated

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[TTTTTTTTTTTT] In applying historical yield and feedstock price variations to projected outcomes, it was recognized that two offsetting factors may cause future biofuel feedstock supply risk to differ from the past. These factors may offset each other: future drought risk may increase with climate change; yet some crops are also becoming increasingly drought resistant.

[UUUUUUUUUUUU] Data on yield volatility were obtained from Bruce Babcock of CARD, Iowa State. Variations in yield were converted to estimated variations in feedstock cost based on elasticities from Thompson, W., Meyer, S. & Westhoff, P. “*How Does Petroleum Price and Corn Yield Volatility Affect Ethanol Markets With and Without an Ethanol Use Mandate?*” Energy Policy, Elsevier, 2009, 37, Pages 745-749.

[VVVVVVVVVVVV] Biofuel production cost economics used in this analysis are based upon estimates from Tao L. and A. Aden 2009, "*The Economics of Current and Future Biofuels,*" In Vitro Cell. Dev.Biol. - Plant, 45:199-217.

[WWWWWWWWWWWW] Volatility is calculated as the standard deviation of annual percentage price changes in the real price of imported crude oil, 1984-2009, U.S. EIA data. This result is robust over the choice of the starting year for the volatility calculation: 2000-2009: 30.0 percent; 29.2 percent; 1990-2009: 26.4 percent; 1980-2009: 27.2 percent; and 1970-2009: 29.5 percent.

based on a summary parameter, “GDP elasticity.” That elasticity is adjusted from historical (i.e., early 1980’s) levels based on the oil expenditure share in GDP. In the Reference Case, from 2010 to 2022, oil expenditures as a cost share of the U.S. economy vary from 2.5 percent in 2010 to peak at 4.7 percent in 2017, while declining thereafter to 3.8 percent by 2020. By way of comparison, in 1983, the oil cost share was 4.6 percent (for which the assumed 1983 macroeconomic adjustment elasticity is -0.041). Under the RFS2 control case, renewable fuel cost shares in the economy are quite small, growing from under 0.1 percent to about 0.2 percent, an order of magnitude lower than the oil cost shares.

The reduction in GDP adjustment losses due to oil shocks is a result of both the reduction in oil price and the slight decrease in oil share (about 0.2%). As mentioned above, the estimated volatility of crude oil price is greater than renewable fuel production costs under the RFS2 control case. This is understandable for two reasons: historical crude prices are more volatile than agricultural commodity prices that are projected to be the renewable fuel feedstocks; and renewable fuel production costs are less volatile than feedstock costs. The combination of these effects—lower costs shares of oil because of the introduction of higher levels of renewable fuels and less volatility in renewable fuel costs compared to oil—leads to the offsetting gains and losses in terms of macroeconomic dislocation costs, with the avoided losses from crude shocks being greater than the added losses from renewable fuel shocks. Estimates of the avoided macroeconomic dislocation benefits, in dollars per barrel of renewable fuel, are displayed in Table 5.2.5-3 below.

**Table 5.2.5-3.**
**Avoided Macroeconomic Dislocations Benefits for the RFS2 Control Case vs. the AEO2007 Reference Case ($ per barrel of renewable fuel)**

| | |
|---|---:|
| Reduction in Dislocation Cost from Oil Shocks | $7.08 |
| Reduction in Dislocation Cost from Renewable Fuel Shocks | -$0.52 |
| Avoided Macroeconomic Dislocation Benefits | $6.56 |

This approach has implications for estimated GDP losses due to shock and price fluctuations. If the use of renewable fuels reduces the expenditure share of oil in the U.S. economy, then the sensitivity of the economy to oil shocks is also reduced, and estimated GDP adjustment losses from oil shocks are lower. These effects are all relatively modest, since the changes in the renewable fuel cost share are fairly modest. However, the overall importance of oil in the economy and the greater estimated volatility of oil prices lead to a significant gain per barrel of oil use avoided. The applicable GDP elasticity for renewable fuel price shocks is much smaller than that for oil, in proportion to the expenditure share of renewable fuels. It does, of course, grow over time with increased use renewable fuels.

Although retail renewable fuel prices will move closely with petroleum prices, and to a lesser extent the renewable fuel plant-gate market prices and feedstock prices, there is still a macroeconomic benefit from replacing oil with renewable fuels. This is true for three reasons. First, the nature of the oil price increase and renewable fuel price increases are quite distinct.

When the price of oil increases from an oil supply shock, the resulting increase in renewable fuels has a very different origin–it is due to substitution toward renewable fuels, and thus reflects a demand response rather than a supply shock. While price change is commonly used as the summary measure of the shock, the underlying quantity changes cannot be forgotten as the root cause of the economic loss. Unlike oil, the quantity of renewable fuel supplied during an oil shock will increase, or at least remain little changed. Second, the short-run increase in the price of renewable fuel is no different from the induced price increase in all other substitutes for oil: energy or non-energy. Adding a new, independent supply source like renewable fuel is equivalent to adding any other alternative fuel, or even to adding a conservation alternative. The price of all of these alternatives will rise to some extent with oil prices, but this substitution effect is part of the solution to the disruption rather than part of the problem. Through substitution, renewable fuels can also dampen the oil price shock, a beneficial effect that is only partially represented in this analysis. Third, to the extent that renewable fuel prices rise with little change in production, the payments will be largely to domestic producers, as windfall gains rather than losses.

### 5.2.6 Estimates of per Barrel Energy Security Benefits

Table 5.2.6-1 below summarizes ORNL's estimate of the energy security benefits associated with the RFS2 renewable fuel volumes, including the components of the energy security benefit.

**Table 5.2.6-1.**
**Energy Security Benefits from the RFS2**
**Control Case vs. the AEO 2007 Reference Case**
**(2007$/barrel of renewable fuel)**

| Effect | Updated ORNL Study |
|---|---|
| Monopsony (best estimate)<br>(range) | $7.86<br>($5.37-$10.71) |
| Macroeconomic Disruption (best estimate)<br>(range) | $6.56<br>($0.94-$12.23) |
| Total (best estimate)<br>(range) | $14.42<br>($6.31-$22.95) |

The literature on the energy security for the last two decades has routinely combined the monopsony and the macroeconomic disruption components when calculating the total value of the energy security premium. However, in the context of using a global value for the Social Cost of Carbon (SCC) the question arises: how should the energy security premium be used when some benefits from the rule, such as the benefits of reducing greenhouse gas emissions, are calculated using a global value? Monopsony benefits represent avoided payments by the U.S. to oil producers in foreign countries that result from a decrease in the world oil price as the U.S. decreases its consumption of imported oil (net of increased imported renewable fuel payments by the U.S.) Although there is clearly a benefit to the U.S. when considered from the domestic perspective, the decrease in price due to decreased demand in the U.S. also represents a loss to other countries. Given the redistributive nature of this effect, do the negative effects on other countries "net out" the positive impacts to the U.S.? If this is the case, then, the monopsony portion of the energy security premium should be excluded from the net benefits calculation for the rule. Based on this reasoning, EPA's estimates of net benefits for this rule exclude the portion of energy security benefits stemming from the U.S. exercising its monopsony power in oil markets. Thus, EPA only includes the macroeconomic disruption/adjustment cost portion of the energy security premium.

However, even when the global value for greenhouse gas reduction benefits is used, an argument can be made that the monopsony benefits should be included in net benefits calculation for this rule. Maintaining the earth’s climate is a global public good and as such requires that a global cooperative perspective be taken on the benefits of GHG mitigation by all nations, including the U.S. Given that a cooperative global approach is required to address the climate change issue, each country (and market participant) should face the global SCC. In other words, using the global SCC does not transform the calculation from a domestic (i.e., U.S.) to a global one. Instead, the global SCC represents the domestic value that the U.S. should utilize to contribute cooperatively to a global solution of the climate change problem.

Energy security, on the other hand, is broadly defined as protecting the U.S. economy against circumstances that threaten significant short- and long-term increases in energy costs. Energy security is inherently a domestic benefit. However, the use of the domestic monopsony benefit is not necessarily in conflict with the use of the global SCC, because the global SCC represents the benefits against which the costs associated with our (i.e., the U.S.’s) domestic mitigation efforts should be judged. In addition, the U.S. values both maintaining the earth’s climate and providing for its own energy security. If this reasoning holds, the two benefits—the global benefits of reducing greenhouse gas emissions and the full energy security premium, including the monopsony benefits—should be counted in the net benefits estimates of the rule. In the final analysis, the Agency determined that the first argument is more compelling and therefore has determined that using only the macroeconomic disruption component of the energy security benefit is the appropriate metric for this rule.

### 5.2.7 Total Energy Security Benefits from RFS2 Rule

The energy security benefits of increasing the total renewable fuel volumes from the AEO 2007 Reference Case volumes of 13.56 billion gallons to the Primary Control Case volumes of 30.5 billion gallons are shown in Table 5.2.7-1. Total annual energy security benefits are estimated by multiplying the change in renewable fuel volumes (16.94 billion gallons or 403 million barrels) and the macroeconomic disruption/adjustment portion of the energy security premium ($6.56/barrel of renewable fuels).

**Table 5.2.7-1.**
**Total Energy Security Benefits from**
**the RFS2 Control Case vs. the AEO 2007 Reference Case**
**(billions of 2007$)**

| **Year** | **2022** |
|---|---:|
| Benefits | $2.6 |

## 5.3. Benefits of Reducing GHG Emissions

### 5.3.1 Introduction

As discussed in Chapter 2, the increased volumes of renewable fuels mandated by the RFS2 standards are projected to reduce greenhouse gas emissions (GHG). This section presents estimates of the economic benefits that could be monetized for the reductions in GHG emissions projected due to the RFS2 renewable fuel volumes. The total benefit estimates were calculated by multiplying a marginal dollar value (i.e., cost per ton) of carbon emissions, also referred to as "social cost of carbon" (SCC), by the anticipated level of emissions reductions in tons.

The SCC values underlying the benefits estimates for this rule represent U.S. government-wide interim values for SCC. As discussed below, federal agencies will use these interim values to assess some of the economic benefits of GHG reductions while an interagency workgroup develops SCC values for use in the long-term. The interim values should not be viewed as an expectation about the results of the longer-term process. Although these values were not used in the NPRM, some commenters raised issues with these values and the methodology used to develop them in response to their publication elsewhere. Many of these issues are being examined by the interagency workgroup.

The rest of this section provides the basis for the interim SCC values, and the estimates of the total climate-related benefits of the RFS2 renewable fuel volumes that follow from these interim values. As discussed below, the interim dollar estimates of the SCC represent a partial accounting of climate change impacts.

In addition to the partial quantitative account presented in this section, a qualitative appraisal of climate-related impacts that are not fully captured in these values is published in other recent climate change analyses. For example, EPA's final Endangerment and Cause or Contribute Findings for Greenhouse Gases under Section 202(a) of the Clean Air Act and the accompanying Technical Support Document (TSD) presents a summary of impacts and risks of climate change projected in the absence of actions to mitigate GHG emissions.[xxxxxxxxxxxx] The TSD synthesizes major findings from the best available scientific assessments of the scientific literature that have gone through rigorous and transparent peer review, including the major assessment reports of both the Intergovernmental Panel on Climate Change (IPCC) and the U.S. Climate Change Science Program (CCSP).

### 5.3.2 Derivation of Interim Social Cost of Carbon Values

The "social cost of carbon" (SCC) is intended to be a monetary measure of the incremental damage resulting from carbon dioxide ($CO_2$) emissions, including (but not limited to) net agricultural productivity loss, human health effects, property damages from sea level rise, and changes in ecosystem services. Any effort to quantify and to monetize the consequences associated with climate change will raise serious questions of science, economics, and ethics. But

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[xxxxxxxxxxxx] See Federal Register /Vol.74, No.2398/Wednesday, December 16, 2009/Rules and Regulations at http://frwebgate4.access.gpo.gov/cgi-bin/PDFgate.cgi?WAISdocID=969788398047+0+2+0&WAISaction=retrieve

with full regard for the limits of both quantification and monetization of impacts, the SCC can be used to provide an estimate of the social benefits of reductions in GHG emissions.

For at least three reasons, any particular figure will be contestable. First, scientific and economic knowledge about the impacts of climate change continues to grow. With new and better information about relevant questions, including the cost, burdens, and possibility of adaptation, current estimates will inevitably change over time. Second, some of the likely and potential damages from climate change—for example, the loss of endangered species—are generally not included in current SCC estimates. These omissions may turn out to be significant in the sense that they may mean that the best current estimates are too low. As noted by the IPCC Fourth Assessment Report, "It is *very likely* that globally aggregated figures underestimate the damage costs because they cannot include many non-quantifiable impacts." Third, when economic efficiency criteria, under specific assumptions, are juxtaposed with ethical considerations, the outcome may be controversial. These ethical considerations, including those involving the treatment of future generations, should and will also play a role in judgments about the SCC (see in particular the discussion of the discount rate, below).

To date, SCC estimates presented in recent regulatory documents have varied within and among agencies, including DOT, DOE, and EPA. For example, a regulation proposed by DOT in 2008 assumed a value of $7 per metric ton $CO_2$[YYYYYYYYYYYY] (2006$) for 2011 emission reductions (with a range of $0-14 for sensitivity analysis). One of the regulations proposed by DOE in 2009 used a range of $0-$20 (2007$). Both of these ranges were designed to reflect the value of damages to the United States resulting from carbon emissions, or the "domestic" SCC. In the final MY2011 CAFE EIS, DOT used both a domestic SCC value of $2/t-$CO_2$ and a global SCC value of $33/t-$CO_2$ (with sensitivity analysis at $80/t-$CO_2$) (in 2006 dollars for 2007 emissions), increasing at 2.4% per year thereafter. The final MY2011 CAFE rule also presented a range from $2 to $80/t-$CO_2$.

In the May 2009 RFS2 Proposal leading to today's final rule, EPA identified preliminary SCC estimates that spanned three orders of magnitude. EPA's May 2009 proposal also presented preliminary global SCC estimates developed from a survey analysis of the peer reviewed literature (i.e., meta analysis). The global mean values from the meta analysis were $68 and $40/t-$CO_2$ for discount rates of 2% and 3% respectively (in 2006 real dollars for 2007 emissions).[ZZZZZZZZZZZZ]

Since publication of the May 2009 RFS2 proposal, a federal interagency working group has established a methodology for selecting a range of interim SCC estimates for use in regulatory analyses. Today's final rule presents the methodology and the resulting interim set of SCC estimates, which reflect the Administration's current understanding of the relevant literature. Recent federal regulatory documents have also presented the interim SCC estimates,

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[YYYYYYYYYYYY] For the purposes of this discussion, we present all values of the SCC as the cost per metric ton of $CO_2$ emissions. Some discussions of the SCC in the literature use an alternative presentation of a dollar per metric ton of carbon. The standard adjustment factor is 3.67, which means, for example, that a SCC of $10 per ton of $CO_2$ would be equivalent to a cost of $36.70 for a ton of carbon emitted. Unless otherwise indicated, a "ton" refers to a metric ton.

[ZZZZZZZZZZZZ] 74 FR 25094 (May 26, 2009).

including a proposal to limit vehicle greenhouse gas emissions that requests public comment on the estimates and underlying methodology.[AAAAAAAAAAAAA]

It should be emphasized that the analysis here is preliminary. These interim estimates are being used for the short-term while an interagency group develops a more comprehensive characterization of the distribution of SCC values for future economic and regulatory analyses. The interim values should not be viewed as an expectation about the results of the longer-term process.

This process will allow the workgroup to explore questions raised in the May 2009 RFS2 Proposal as they are relevant to the development of SCC values for use in the long-term. The workgroup may evaluate factors not currently captured in today's estimates due to time constraints, such as the quantification of additional impact categories where possible and an uncertainty analysis. The Administration will seek comment on all of the scientific, economic, and ethical issues before establishing improved estimates for use in future rulemakings.

The outcomes of the Administration's process to develop interim values are judgments in favor of a) global rather than domestic values, b) an annual growth rate of 3%, and c) interim global SCC estimates for 2007 (in 2007 dollars) of $56, $34, $20, $10, and $5 per metric ton of $CO_2$. The interim set of values is based on the following judgments.

### 5.3.2.1 Global and Domestic Measures

Because of the distinctive nature of the climate change problem, we present both a global SCC and a fraction of that value that represents impacts that may occur within the borders of the U.S. alone, or a "domestic" SCC, but fix our attention on the global measure. This approach represents a departure from past practices, which relied, for the most part, on domestic measures. As a matter of law, both global and domestic values are permissible; the relevant statutory provisions are ambiguous and allow selection of either measure.[BBBBBBBBBBBBB]

Under OMB guidance, analysis from the domestic perspective is required, while analysis from the international perspective is optional. The domestic decisions of one nation are not typically based on a judgment about the effects of those decisions on other nations. But the climate change problem is highly unusual in the sense that it involves (a) a global public good in which (b) the emissions of one nation may inflict significant damages on other nations and (c) the United States is actively engaged in promoting an international agreement to reduce worldwide emissions.

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[AAAAAAAAAAAAA] Federal Register 40 CFR Parts 86 and 600, September 28, 2009 "Proposed Rulemaking To Establish Light-Duty Vehicle Greenhouse Gas Emission Standards and Corporate Average Fuel Economy Standards; Proposed Rule"

[BBBBBBBBBBBBB] It is true that federal statutes are presumed not to have extraterritorial effect, in part to ensure that the laws of the United States respect the interests of foreign sovereigns. But use of a global measure for the SCC does not give extraterritorial effect to federal law and hence does not intrude on such interests.

In these circumstances, we believe the global measure is preferred. Use of a global measure reflects the reality of the problem and is consistent with the continuing efforts of the United States to ensure that emissions reductions occur in many nations.

Domestic SCC values are also presented. The development of a domestic SCC is greatly complicated by the relatively few region- or country-specific estimates of the SCC in the literature. One potential source of estimates comes from EPA's ANPR Benefits TSD, using the FUND model. The resulting estimates suggest that the ratio of domestic to global benefits varies with key parameter assumptions. With a 3% discount rate, for example, the U.S. benefit is about 6 percent of the global benefit of GHG reductions for the "central" (mean) FUND results, while, for the corresponding "high" estimates associated with higher climate sensitivity and lower global economic growth, the U.S. benefit is less than 4 percent of the global benefit. With a 2 percent discount rate, the U.S. share is about 2-5 percent of the global estimate.

Based on this available evidence, an interim domestic SCC value equal to 6 percent of the global damages is proposed. It is recognized that the 6 percent figure is approximate and highly speculative and alternative approaches will be explored before establishing improved values for future rulemakings. However, it should be noted that it is difficult to properly apportion global benefits to different regions, because not all the damages citizens of one country would be willing to pay to avoid will occur only within their own borders. For example, impacts outside U.S. border can have significant welfare implications for U.S. populations (e.g. tourism, disaster relief) and if not included, these omissions will lead to an underestimation of the "domestic" SCC.

### 5.3.2.2 Filtering existing analyses

There are numerous SCC estimates in the existing literature, and it is reasonable to make use of those estimates in order to produce a figure for current use. A starting point is provided by the meta-analysis in Richard Tol, 2008.[cccccccccccc] With that starting point, the Administration proposes to "filter" existing SCC estimates by using those that (1) are derived from peer-reviewed studies; (2) do not weight the monetized damages to one country more than those in other countries; (3) use a "business as usual" climate scenario; and (4) are based on the most recent published version of each of the three major integrated assessment models (IAMs): FUND, PAGE, and DICE.

Proposal (1) is based on the view that those studies that have been subject to peer review are more likely to be reliable than those that have not. Proposal (2) avoids treating the citizens of one nation (or different citizens within the US) differently on the basis of income considerations, which some may find controversial and in any event would complicate that analysis. Further it is consistent with the potential compensation tests of Kaldor (1939) and Hicks (1940), which form the conceptual foundations of benefit-cost analysis and use unweighted sums of willingness to pay. Finally, this is the approach used in rulemakings across a variety of settings and consequently keeps USG policy consistent across contexts.

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[cccccccccccc] Richard Tol, The Social Cost of Carbon: Trends, Outliers, and Catastrophes, Economics: The Open-Access, Open-Assessment E-Journal, Vol. 2, 2008-25. http://www.economics-ejournal.org/economics/journalarticles/2008-25 (2008).

Proposal (3) stems from the judgment that as a general rule, the proper way to assess a policy decision is by comparing the implementation of the policy against a counterfactual state where the policy is not implemented. In addition, our expectation is that most policies to be evaluated using these interim SCC estimates will constitute small enough changes to the larger economy to safely assume that the marginal benefits of emissions reductions will not change between the baseline and policy scenarios.

Proposal (4) is based on four complementary judgments. First, the FUND, PAGE, and DICE models now stand as the most comprehensive and reliable efforts to measure the economic damages from climate change. Second, the latest versions of the three IAMs are likely to reflect the most recent evidence and learning, and hence they are presumed to be superior to those that preceded them. However, it is acknowledged that the most recently published results do not necessarily repeat prior modeling exercises with an updated model, so valuable information may be lost, for instance, estimates of the SCC using specific climate sensitivities or economic scenarios. In addition, although some older model versions were used to produce estimates between 1996 and 2001, there have been no significant modeling paradigm changes since 1996.

Third, any effort to choose among them, or to reject one in favor of the others, would be difficult to defend at the present time. In the absence of a clear reason to choose among them, it is reasonable to base the SCC on all of them. Fourth, in light of the uncertainties associated with the SCC, a range of values is more representative and the additional information offered by different models is important.

### 5.3.2.3 Use a Model-weighted Average of the Estimates at Each Discount Rate

At this time, a strong reason to prefer any of the three major IAMs (FUND, PAGE, and DICE) over the others has not been identified. Accordingly, to address the concern that certain models not be given unequal weight relative to the other models, the estimates are based on an equal weighting of the means of the estimates from each of the models. Among estimates that remain after applying the filter, we begin by taking the average of all estimates within a model. The estimated SCC is then calculated as the average of the three model-specific averages. This approach is used to ensure that models with a greater number of published results do not exert unequal weight on the interim SCC estimates. However, note that the resulting set of SCC estimates does not provide information about variability among or within models except in so far as they have different discounting assumptions. In the future interagency process to generate a more comprehensive distribution of SCC, we expect to exercise the available SCC models in a systematic manner such that the resulting distributions of SCC values may incorporate a wider range of uncertainties including discount rates, growth rates, climate sensitivities, and other important parameters. This may lead to changes in the span of SCC estimates that are relevant for policy analyses.

### 5.3.2.4 Apply a 3 Percent Annual Growth Rate to the Chosen SCC Values

SCC is expected to increase over time, because future emissions are expected to produce larger incremental damages as physical and economic systems become more stressed as the magnitude of climate change increases. Indeed, an implied growth rate in the SCC can be produced by most of the models that estimate economic damages caused by increased GHG emissions in future years. But neither the rate itself nor the information necessary to derive its implied value is commonly reported. In light of the limited amount of debate thus far about the appropriate growth rate of the SCC, applying a rate of 3 percent per year seems appropriate at this stage. This value is consistent with the range recommended by IPCC (2007) and close to the latest published estimate (Hope 2008).

### 5.3.2.5 Discount Rates

For estimation of the benefits associated with the mitigation of climate change, one of the most complex issues involves the appropriate discount rate. OMB's current guidance offers a detailed discussion of the relevant issues and calls for discount rates of 3 percent and 7 percent. It also permits a sensitivity analysis with low rates (1 – 3 percent) for intergenerational problems: "If your rule will have important intergenerational benefits or costs you might consider a further sensitivity analysis using a lower but positive discount rate in addition to calculating net benefits using discount rates of 3 and 7 percent."[DDDDDDDDDDDDD]

The choice of a discount rate, especially over long periods of time, raises highly contested and exceedingly difficult questions of science, economics, philosophy, and law. See, e.g., William Nordhaus, The Challenge of Global Warming (2008); Nicholas Stern, The Economics of Climate Change (2008); Discounting and Intergenerational Equity (Paul Portney and John Weyant eds. 1999). It is not clear that future generations would be willing to trade environmental quality for consumption at the same rate as the current generations. Under imaginable assumptions, decisions based on cost-benefit analysis with high discount rates might harm future generations – at least if investments are not made for the benefit of those generations. See Robert Lind, Analysis for Intergenerational Discounting, id. at 173, 176-177. It is also possible that the use of low discount rates for particular projects might itself harm future generations, by diverting resources from private or public sector investments with higher rates of return for future generations. In the context of climate change, questions of intergenerational equity are especially important.

Because of the substantial length of time in which $CO_2$ and other GHG emissions reside in the atmosphere, choosing a discount rate which is higher than the actual discount rate could result in irreversible changes in $CO_2$ concentrations, and possibly irreversible climate changes (unless substantial reductions in short-lived climate forcing emissions are achieved). Even if these changes are reversible, delaying mitigation efforts could result in substantially higher costs of stabilizing $CO_2$ concentrations. On the other hand, using too low a discount rate in benefit-cost analysis may recommend some potentially economically unwarranted investments in mitigation. In many cases these investments could be discontinued with little long term economic disruptions. However, it is also possible that the use of low discount rates for particular projects might itself harm future generations, by ensuring that resources are not used in a way that would greatly benefit them.

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[DDDDDDDDDDDDD] See OMB Circular A-4, pp. 35-36, citing Portney and Weyant, eds. (1999), Discounting and Intergenerational Equity, Resources for the Future, Washington, DC.

Reasonable arguments support the use of a 3 percent discount rate. First, that rate is among the two figures suggested by OMB guidance, and hence it fits with existing national policy. Second, it is standard to base the discount rate on the compensation that people receive for delaying consumption, and the 3 percent is close to the risk-free rate of return, proxied by the return on long term inflation-adjusted U.S. Treasury Bonds, as of this writing. Although these rates are currently closer to 2.5 percent, the use of 3 percent provides an adjustment for the liquidity premium that is reflected in these bonds' returns. However, this approach does not adjust for the significantly longer time horizon associated with climate change impacts. It also could be argued that the appropriate interest rate should be lower than 3 percent if the benefits of climate mitigation policies tend to be higher than expected in time periods when the returns to investments in rest of the economy are lower than normal.

At the same time, others would argue that a 5 percent discount rate can be supported. The argument relies on several assumptions. First, this rate can be justified by reference to the level of compensation for delaying consumption, because it fits with market behavior with respect to *individuals'* willingness to trade-off consumption across periods as measured by the estimated post-tax average real returns to risky private investments (e.g., the S&P 500). In the climate setting, the 5 percent discount rate may be preferable to the riskless rate because the benefits to mitigation are not known with certainty. In principal, the correct discount rate would reflect the variance in payoff from climate mitigation policy and the correlation between the payoffs of the policy and the broader economy.[EEEEEEEEEEEE]

Second, 5 percent, and not 3 percent, is roughly consistent with estimates implied by inputs to the theoretically derived Ramsey equation presented below, which specifies the optimal time path for consumption. That equation specifies the optimal discount rate as the sum of two components. The first term (the product of the elasticity of the marginal utility of consumption and the growth rate of consumption) reflects the fact that consumption in the future is likely to be higher than consumption today, so diminishing marginal utility implies that the same monetary damage will cause a smaller reduction of utility in the future. Standard estimates of this term from the economics literature are in the range of 3 percent-5 percent.[FFFFFFFFFFFF] The second component reflects the possibility that a lower weight should be placed on utility in the future, to account for social impatience or extinction risk, which is specified by a pure rate of time preference (PRTP). A common estimate of the PRTP is 2 percent, though some observers believe that a principle of intergenerational equity suggests that the PRTP should be close to zero. It

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[EEEEEEEEEEEE] Specifically, if the benefits of the policy are highly correlated with the returns from the broader economy, then the market rate should be used to discount the benefits. If the benefits are uncorrelated with the broader economy the long term government bond rate should be applied. Furthermore, if the benefits are negatively correlated with the broader economy, a rate less than that on long term government bonds should be used (Lind, 1982 pp. 89-90).

[FFFFFFFFFFFF] For example, *see:* Arrow KJ, Cline WR, Maler K–G, Munasinghe M, Squitieri R, Stiglitz JE. 1996. Intertemporal equity, discounting, and economic efficiency. Chapter 4 in Economic and Social Dimensions of Climate Change: Contribution of Working Group III to the Second Assessment Report, Summary for Policy Makers. Cambridge: Cambridge University Press; Dasgupta P. 2008. Discounting climate change. Journal of Risk and Uncertainty 37:141–169; Hoel M, Sterner T. 2007. Discounting and relative prices. Climatic Change 84:265–280; Nordhaus WD. 2008. A Question of Balance: Weighing the Options on Global Warming Policies. New Haven, CT: Yale University Press; Stern N. 2008. The economics of climate change. The American Economic Review 98(2):1–37..

follows that discount rate of 5 percent is near the middle of the range of values that are able to be derived from the Ramsey equation.[GGGGGGGGGGGGG]

It is recognized that the arguments above – for use of market behavior and the Ramsey equation – face objections in the context of climate change, and of course there are alternative approaches. In light of climate change, it is possible that consumption in the future will not be higher than consumption today, and if so, the Ramsey equation will suggest a lower figure. The historical evidence is consistent with rising consumption over time. [HHHHHHHHHHHHH]

Some critics note that using observed interest rates for inter-generational decisions imposes current preferences on future generations, which some economists say may not be appropriate. For generational equity, they argue that the discount rate should be below market rates to correct for market distortions and inefficiencies in intergenerational transfers of wealth (which are presumed to compensate future generations for damage), and to treat generations equitably based on ethical principles (see Broome 2008).[IIIIIIIIIIIII]

Additionally, some analyses attempt to deal with uncertainty with respect to interest rates over time. We explore below how this might be done.[JJJJJJJJJJJJJ]

### 5.3.2.6 Interim Social Cost of Carbon Estimates

The application of the methodology outlined above yields interim estimates of the SCC that are reported in Table 5.3.2.6-1. These estimates are reported separately using 3 percent and 5 percent discount rates. The cells are empty in rows 10 and 11, because these studies did not report estimates of the SCC at a 3 percent discount rate. The model-weighted means are reported in the final or summary row; they are \$34 per t-$CO_2$ at a 3% discount rate and \$5 per t-$CO_2$ with a 5 percent discount rate.

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[GGGGGGGGGGGGG] Sterner and Persson (2008) note that a consistent treatment of the marginal utility of consumption would require that if higher discount rates are justified by the diminishing marginal utility of consumption, e.g., a dollar of damages is worth less to future generations because they have greater income, then so-called equity weights should be used to account for the higher value that countries with lower income would place on a dollar of damages relative to the U.S. This is a consistent and logical outcome of application of the Ramsey framework. Because the distribution of climate change related damages is expected to be skewed towards developing nations with lower incomes, this can have significant implications for estimates of total global SCC if the Ramsey framework is used to derive discount rates.

[HHHHHHHHHHHHH] However, because climate change impacts may be outside the bounds of historical evidence, predictions about future growth in consumption based on past experience may be inaccurate.

[IIIIIIIIIIIII] See Arrow, K.J., W.R. Cline, K-G Maler, M. Munasinghe, R. Squiteri, J.E.Stiglitz, 1996. "Intertemporal equity, discounting and economic efficiency," in Climate Change 1995: Economic and Social Dimensions of Climate Change, Contribution of Working Group III to the Second Assessment Report of the Intergovernmental Panel on Climate Change. See also Weitzman, M.L., 1999, in Portney P.R. and Weyant J.P. (eds.), Discounting and Intergenerational Equity, Resources for the Future, Washington, D.C.

[JJJJJJJJJJJJJ] Richard Newell and William Pizer, Discounting the distant future: how much do uncertain rates increase valuations? J. Environ. Econ. Manage. 46 (***2003***) 52-71.

### Table 5.3.2.6-1.
### Global Social Cost of Carbon (SCC) Estimates ($/t-$CO_2$ in 2007 (2007$)), Based on 3 Percent and 5 Percent Discount Rates *

| | **Model** | **Study** | **Climate Scenario** | 3% | 5% |
|---|---|---|---|---|---|
| 1 | FUND | Anthoff et al. 2009 | FUND default | 6 | -1 |
| 2 | FUND | Anthoff et al. 2009 | SRES A1b | 1 | -1 |
| 3 | FUND | Anthoff et al. 2009 | SRES A2 | 9 | -1 |
| 4 | FUND | Link and Tol 2004 | No THC | 12 | 3 |
| 5 | FUND | Link and Tol 2004 | THC continues | 12 | 2 |
| 6 | FUND | Guo et al. 2006 | Constant PRTP | 5 | -1 |
| 7 | FUND | Guo et al. 2006 | Gollier discount 1 | 14 | 0 |
| 8 | FUND | Guo et al. 2006 | Gollier discount 2 | 7 | -1 |
| | | | **FUND Mean** | **8.47** | **0** |
| 9 | PAGE | Wahba & Hope 2006 | A2-scen | 59 | 7 |
| 10 | PAGE | Hope 2006 | | | 7 |
| 11 | DICE | Nordhaus 2008 | | | 8 |
| **Summary** | | | **Model-weighted Mean** | **34** | **5** |

*The sample includes all peer reviewed, non-equity-weighted estimates included in Tol (2008), Nordhaus (2008), Hope (2008), and Anthoff et al. (2009), that are based on the most recent published version of FUND, PAGE, or DICE and use business-as-usual climate scenarios.[KKKKKKKKKKKKK][LLLLLLLLLLLL] All values are based on the best available information from the underlying studies about the base year and year dollars, rather than the Tol (2008) assumption that all estimates included in his review are 1995 values in 1995$. All values were updated to 2007 using a 3% annual growth rate in the SCC, and adjusted for inflation using GDP deflator.

In today's rule, benefits of reducing GHG emissions have been estimated using global SCC values of $34 and $5 as these represent the estimates associated with the 3 percent and 5

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[KKKKKKKKKKKKK] Most of the estimates in Table 1 rely on climate scenarios developed by the Intergovernmental Panel on Climate Change (IPCC). The IPCC published a new set of scenarios in 2000 for use in the Third Assessment Report (Special Report on Emissions Scenarios - SRES). The SRES scenarios define four narrative storylines: A1, A2, B1 and B2, describing the relationships between the forces driving greenhouse gas and aerosol emissions and their evolution during the 21st century for large world regions and globally. Each storyline represents different demographic, social, economic, technological, and environmental developments that diverge in increasingly irreversible ways. The storylines are summarized in Nakicenovic et al., 2000 (see also http://sedac.ciesin.columbia.edu/ddc/sres/ ). Although they were intended to represent BAU scenarios, at this point in time the B1 and B2 storylines are widely viewed as representing policy cases rather than business-as-usual projections, estimates derived from these scenarios to be less appropriate for use in benefit-cost analysis. They are therefore excluded.

[LLLLLLLLLLLL] Guo et al. (2006) report estimates based on two Gollier discounting schemes. The Gollier discounting assumes complex specifications about individual utility functions and risk preferences. After various conditions are satisfied, declining social discount rates emerge. Gollier Discounting Scheme 1 employs a certainty-equivalent social rate of time preference (SRTP) derived by assuming the regional growth rate is equally likely to be 1% above or below the original forecast growth rate. Gollier Discounting Scheme 2 calculates a certainty-equivalent social rate of time preference (SRTP) using five possible growth rates, and applies the new SRTP instead of the original. Hope (2008) conducts Monte Carlo analysis on the PRTP component of the discount rate. The PRTP is modeled as a triangular distribution with a min value of 1%/yr, a most likely value of 2 %/yr, and a max value of 3 %/yr.

percent discount rates, respectively.[MMMMMMMMMMMMM] The 3 percent and 5 percent estimates have independent appeal and at this time a clear preference for one over the other is not warranted. Thus, we have also included – and centered our current attention on – the average of the estimates associated with these discount rates, which is $20. (Based on the $20 global value, the approximate domestic fraction of these benefits would be $1.20 per metric ton of $CO_2$ assuming that domestic benefits are 6% of the global benefits.

The distinctions between sets of estimates generated using different discount rates are due only in part to discount rate differences, because the models and parameters used to generate the estimates in the sets associated with different discount rates also vary.

It is true that there is uncertainty about interest rates over long time horizons. Recognizing that point, Newell and Pizer (2003) have made a careful effort to adjust for that uncertainty. The Newell-Pizer approach models discount rate uncertainty as something that evolves over time.[NNNNNNNNNNNNN] This is a different way to model discount rate uncertainty than the approach outlined above, which assumes there is a single discount rate with equal probability of 3 percent and 5 percent.

Table 5.3.2.6-2 reports on the application of the Newell-Pizer adjustments. The precise numbers depend on the assumptions about the data generating process that governs interest rates. Columns (1a) and (1b) assume that "random walk" model best describes the data and uses 3 percent and 5 percent discount rates, respectively. Columns (2a) and (2b) repeat this, except that it assumes a "mean-reverting" process. While the empirical evidence does not rule out a mean-reverting model, Newell and Pizer find stronger empirical support for the random walk model.

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[MMMMMMMMMMMMM] It should be noted that reported discount rates may not be consistently derived across models or specific applications of models: while the discount rate may be identical, it may reflect different assumptions about the individual components of the Ramsey equation identified earlier.

[NNNNNNNNNNNNN] In contrast, an alternative approach based on Weitzman (2001) would assume that there is a constant discount rate that is uncertain and represented by a probability distribution. The Newell and Pizer, and Weitzman approaches are relatively recent contributions to the literature. .

**Table 5.3.2.6-2.**
**Global Social Cost of Carbon (SCC) Estimates ($ per metric ton $CO_2$ in 2007 (2007$))*, Using Newell & Pizer (2003) Adjustment for Future Discount Rate Uncertainty****

| | Model | Study | Climate Scenario | Random-walk model | | Mean-reverting model | |
|---|---|---|---|---|---|---|---|
| | | | | 3% (1a) | 5% (1b) | 3% (2a) | 5% (2b) |
| 1 | FUND | Anthoff et al. 2009 | FUND default | 10 | 0 | 7 | -1 |
| 2 | FUND | Anthoff et al. 2009 | SRES A1b | 2 | 0 | 1 | -1 |
| 3 | FUND | Anthoff et al. 2009 | SRES A2 | 15 | 0 | 10 | -1 |
| 4 | FUND | Link and Tol 2004 | No THC | 21 | 6 | 13 | 4 |
| 5 | FUND | Link and Tol 2004 | THC continues | 21 | 4 | 13 | 2 |
| 6 | FUND | Guo et al. 2006 | Constant PRTP | 9 | 0 | 6 | -1 |
| 7 | FUND | Guo et al. 2006 | Gollier discount 1 | 14 | 0 | 14 | 0 |
| 8 | FUND | Guo et al. 2006 | Gollier discount 2 | 7 | -1 | 7 | -1 |
| | | | **FUND Mean** | **12** | **1** | **9** | **0** |
| 9 | PAGE | Wahba & Hope 2006 | A2-scen | 100 | 13 | 65 | 8 |
| 10 | PAGE | Hope 2006 | | | 13 | | 8 |
| 11 | DICE | Nordhaus 2008 | | | 15 | | 9 |
| **Summary** | | | **Model-weighted Mean** | **56** | **10** | **37** | **6** |

*The sample includes all peer reviewed, non-equity-weighted estimates included in Tol (2008), Nordhaus (2008), Hope (2008), and Anthoff et al. (2009), that are based on the most recent published version of FUND, PAGE, or DICE and use business-as-usual climate scenarios. All values are based on the best available information from the underlying studies about the base year and year dollars, rather than the Tol (2008) assumption that all estimates included in his review are 1995 values in 1995$. All values were updated to 2007 using a 3% annual growth rate in the SCC, and adjusted for inflation using GDP deflator. See the Notes to Table 1 for further details.
**Assumes a starting discount rate of 3% or 5%. Newell and Pizer (2003) based adjustment factors are not applied to estimates from Guo et al. (2006) that use a different approach to account for discount rate uncertainty (rows 7-8). Note that the correction factor from Newell and Pizer is based on the DICE model. The proper adjustment may differ for other integrated assessment models that produce different time schedules of marginal damages. We would expect this difference to be minor.

The resulting estimates of the social cost of carbon are necessarily greater. When the adjustments from the random walk model are applied, the estimates of the social cost of carbon are $10 and $56 per ton of $CO_2$, with the 5 percent and 3 percent discount rates, respectively. The application of the mean-reverting adjustment yields estimates of $6 and $37. Relying on the random walk model, analyses are also conducted with the value of the SCC set at $10 and $56.

### 5.3.2.7 Caveats

There are at least four caveats to the approach outlined above.

First, the impacts of climate change are expected to be widespread, diverse, and heterogeneous. In addition, the exact magnitude of these impacts is uncertain, because of the inherent randomness in the Earth's atmospheric processes, the U.S. and global economies, and the behaviors of current and future populations. The existing IAMs do not currently individually account for and assign value to all of the important physical and other impacts of climate change that are recognized in the climate change literature.[OOOOOOOOOOOOO] Therefore, as noted by the IPCC, SCC estimates are "very likely" underestimated.[PPPPPPPPPPPPP] In addition, the SCC approach also likely underestimates the value of GHG reductions because the marginal values apply only to $CO_2$ emissions, which have different impacts than non-$CO_2$ emissions because of variances in atmospheric lifetimes and radiative forcing.[QQQQQQQQQQQQQ] Although it is likely that our capability to quantify and monetize impacts will improve with time, it is also likely that even in future applications, a number of potentially significant benefits categories will remain unmonetized. In order to more fully characterize of benefits of mitigation these non-monetized benefits should be discussed along with monetized benefits based on the SCC.

Second, in the opposite direction, it is unlikely that the damage estimates adequately account for the directed technological change that climate change will cause. In particular, climate change will increase the return on investment to develop technologies that allow individuals to better cope with climate change. For example, it is likely that scientists will develop crops that are better able to withstand high temperatures. In this respect, the current estimates may overstate the likely quantified damages, though the costs associated with the investments in adaptive technologies must also be considered (technologies must also be included in the calculations, as the benefits should reflect net welfare changes to society).

Third, there has been considerable recent discussion of the risk of catastrophic impacts and of how best to account for worst-case scenarios. Recent research by Weitzman (2009) specifies some conditions under which the possibility of catastrophe would undermine the use of IAMs and conventional cost-benefit analysis. This research requires further exploration before its generality is known and the proper way to incorporate it into regulatory reviews is understood.

Fourth, it is also worth noting that the SCC estimates are only relevant for incremental policies relative to the projected baselines, which capture business-as-usual scenarios. To evaluate non-marginal changes, such as might occur if the U.S. acts in tandem with other nations, then it might be necessary to go beyond the simple expedient of using the SCC along the BAU path. This would require explicitly calculating the total benefits in a move from the BAU scenario to the policy scenario, without imposing the restriction that the marginal benefit remains constant over this range.

#### 5.3.2.8 Other Options

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[OOOOOOOOOOOOO] Examples of impacts that are difficult to monetize, and have generally not been included in SCC estimates, include risks from extreme weather (death, disease, agricultural damage, and other economic damage from droughts, floods and wildfires) and possible long-term catastrophic events, such as collapse of the West Antarctic ice sheet or the release of large amounts of methane from melting permafrost.

[PPPPPPPPPPPPP] IPCC WGII. 2007. *Climate Change 2007 - Impacts, Adaptation and Vulnerability Contribution of Working Group II to the Fourth Assessment Report of the IPCC.*

[QQQQQQQQQQQQQ] Radiative forcing is the change in the balance between solar radiation entering the atmosphere and the Earth's radiation going out. On average, a positive radiative forcing tends to warm the surface of the Earth while negative forcing tends to cool the surface. Greenhouse gases have a positive radiative forcing because they absorb and emit heat. See http://www.epa.gov/climatechange/science/recentac.html for more general information about GHGs and climate science.

The Administration considered other interim SCC options in addition to the approach described above. Similar to May 2009 RFS2 Proposal, one alternative option was to bring in SCC estimates in studies published after 1995, rather than limiting the estimates to those in studies relying on the most recent published version of each of the three major integrated assessment models: PAGE, FUND, and DICE. Although some older model versions (and old versions of other models) were used to produce estimates between 1996 and 2001, there have been no significant modeling paradigm changes since 1996. Rather, improvements to PAGE, FUND, and DICE since 1996 have reflected incremental technical enhancements.

Another option was to select a range of SCC values for separate discount rates. For example, sensitivity analysis could be conducted at the lowest and highest SCC values reported in the filtered set of estimates for each discount rate considered. If considering SCC estimates from studies published after 1995 and a discount rate of 2 percent, this option would result in a range of SCC values of \$5/t-$CO_2$ to \$260/t-$CO_2$ (2007 emissions in 2007 dollars); at a 3 percent discount rate, the range would be \$0 to \$58/ t-$CO_2$.

Finally, we considered that the use of certain key assumptions under the Ramsey framework, such as placing approximately equal weight on the welfare of current and future generations, would imply use of a 2% discount rate. The Newell and Pizer (2003) method applied to recent long-term risk free rates would likewise be approximately consistent with a rate of 2 percent.[RRRRRRRRRRRRR]

### 5.3.2.9 Ongoing SCC Development

As noted, this is an emphatically interim SCC value. The judgments herein will be subject to further scrutiny and exploration.

### 5.3.3 Application of Interim SCC Estimates to GHG Emissions Reductions from this Final Rule

While no single rule or action can independently achieve the deep worldwide emissions reductions necessary to halt and reverse the growth of GHGs, the combined effects of multiple strategies to reduce GHG emissions domestically and abroad could make a major difference in the climate change impacts experienced by future generations.[SSSSSSSSSSSSS] The projected net GHG emissions reductions associated with this final rule reflect an incremental change to projected total global emissions. Given that the climate response is projected to be a marginal change relative to the baseline climate, we estimate the marginal value of changes in climate change impacts over time and use this value to measure the monetized marginal benefits of the GHG emissions reductions projected for this rule.

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[RRRRRRRRRRRRR] Specifically, Newell and Pizer (2003) found that modeling of uncertainty in economic growth causes the effective discount rate to decline over time. When starting at a 4% discount rate, the effective discount rate is 2% at 100 years and 1% at 200 years.

[SSSSSSSSSSSSS] The Supreme Court recognized in *Massachusetts v. EPA* that a single action will not on its own achieve all needed GHG reductions, noting that “[a]gencies, like legislatures, do not generally resolve massive problems in one fell regulatory swoop.’’ See *Massachusetts v.* EPA, 549 U.S. at 524 (2007).

Accordingly, EPA has used the set of interim, global SCC values described above to estimate the benefits resulting from the renewable fuel volumes mandated by EISA. The interim SCC values, which reflect the Administration's interim interpretation of the current literature, are \$5, \$10, \$20, \$34, and \$56, in 2007 dollars, and are based on a $CO_2$ emissions change of 1 metric ton in 2007. Table 5.3.3-1 presents the interim SCC values for the years 2007 and 2022 in 2007 dollars.

**Table 5.3.3-1. Interim SCC Schedule (2007\$ per metric tonne of $CO_2$)**

| Year | 5% | 5% (Newell-Pizer)* | Average SCC from 3% and 5% | 3% | 3% (Newell-Pizer)* |
|---|---|---|---|---|---|
| **2007** | \$5 | \$10 | \$20 | \$34 | \$56 |
| **2022** | \$8 | \$16 | \$30 | \$53 | \$88 |

Note: The SCC values are dollar-year and emissions-year specific. These values are presented in 2007\$, for individual year of emissions. To determine values for years not presented in the table, use a 3% growth rate. SCC values represent only a partial accounting for climate impacts.
*SCC values are adjusted based on Newell and Pizer (2003) to account to future uncertainty in discount rates.

Tables 5.3.3-2 through 5.3.3-4 provide, for the high, base, and low cases, the average annual GHG emissions reductions in 2022. The annualized emissions reductions are multiplied by the SCC estimates for 2022 from Table 5.3.3-1 to produce the average annual monetized benefit from the emissions reductions from the rule for $CO_2$-equivalent GHGs. This is equivalent to taking the time stream of emissions from the increase in renewable fuel volumes, multiplying them by the SCC (which is increasing at a rate of 3 percent per year), and then discounting the stream of benefits by 3 percent.

**Table 5.3.3-2.**
**Average Annual Emissions Reduction (Million Metric Tonnes $CO_2$-e) and Monetized Benefits (Million 2007\$) of RFS-2 Volumes in 2022, High Case**

| | $CO_2$ | Non-$CO_2$ GHG | Total GHG |
|---|---|---|---|
| **Emissions Reductions** | 148.525 | -8.234 | 140.291 |
| **5%** | \$1,188 | -\$66 | \$1,122 |
| **5% (Newell-Pizer)** | \$2,376 | -\$132 | \$2,245 |
| **Average SCC from 3% and 5%** | \$4,515 | -\$250 | \$4,265 |
| **3%** | \$7,842 | -\$435 | \$7,407 |
| **3% (Newell-Pizer)** | \$13,069 | -\$725 | \$12,344 |

### Table 5.3.3-3.
### Average Annual Emissions Reduction (Million Metric Tonnes $CO_2$-e) and Monetized Benefits (Million 2007$) of RFS-2 Volumes in 2022, Base Case

| | $CO_2$ | Non-$CO_2$ GHG | Total GHG |
|---|---|---|---|
| **Emissions Reductions** | 146.645 | -8.234 | 138.411 |
| **5%** | $1,173 | -$66 | $1,107 |
| **5% (Newell-Pizer)** | $2,346 | -$132 | $2,215 |
| **Average SCC from 3% and 5%** | $4,458 | -$250 | $4,208 |
| **3%** | $7,743 | -$435 | $7,308 |
| **3% (Newell-Pizer)** | $12,903 | -$725 | $12,179 |

### Table 5.3.3-4.
### Average Annual Emissions Reduction (Million Metric Tonnes $CO_2$-e) and Monetized Benefits (Million 2007$) of RFS-2 Volumes in 2022, Low Case

| | $CO_2$ | Non-$CO_2$ GHG | Total GHG |
|---|---|---|---|
| **Emissions Reductions** | 144.338 | -8.234 | 136.104 |
| **5%** | $1,155 | -$66 | $1,089 |
| **5% (Newell-Pizer)** | $2,309 | -$132 | $2,178 |
| **Average SCC from 3% and 5%** | $4,388 | -$250 | $4,138 |
| **3%** | $7,621 | -$435 | $7,186 |
| **3% (Newell-Pizer)** | $12,700 | -$725 | $11,976 |

Table 5.3.3-5 provides, for the high, base, and low cases, the monetized benefits from the emissions reductions from the increase in renewable fuel volumes for $CO_2$-equivalent GHGs in 2022. The SCC estimates for 2022 increase at a rate of 3 percent per year, and are then multiplied by the stream of emissions for each respective year for 30 years. The monetized benefits in table 5.3.3-5 represent the net present value of these emissions for 30 years using a discount rate of 7 percent.

### Table 5.3.3-5.
### Monetized Benefits (Million 2007$) of RFS-2 Volumes in 2022 Using a 7% Discount Rate

| | High | Base | Low |
|---|---|---|---|
| **5%** | $606 | $620 | $631 |
| **5% (Newell-Pizer)** | $1,212 | $1,239 | $1,262 |
| **Average SCC from 3% and 5%** | $2,302 | $2,355 | $2,397 |
| **3%** | $3,999 | $4,089 | $4,163 |
| **3% (Newell-Pizer)** | $6,665 | $6,816 | $6,939 |

## 5.4 Quantified and Monetized Co-pollutant Health and Environmental Impacts

### 5.4.1 Overview

This section describes EPA's analysis of the co-pollutant health and environmental impacts that can be expected to occur as a result of the increase in renewable fuel use throughout the period from initial implementation through 2022. Although the purpose of this final rule is to implement the renewable fuel requirements established by the Energy Independence and Security Act (EISA) of 2007, the increased use of renewable fuels will also impact emissions of criteria and air toxic pollutants and their resultant ambient concentrations. The fuels changes detailed in Section 3.1 of the RIA will influence emissions of VOCs, PM, $NO_X$, and $SO_X$ and air toxics and affect exhaust and evaporative emissions of these pollutants from vehicles and equipment. They will also affect emissions from upstream sources such as fuel production, storage, distribution and agricultural emissions. Any decrease or increase in ambient ozone, $PM_{2.5}$, and air toxics associated with the increased use of renewable fuels will impact human health in the form of a decrease or increase in the risk of incurring premature death and other serious human health effects, as well as other important public health and welfare effects.

This analysis reflects the impact of the 2022 mandated renewable fuel volumes (the "RFS2 control case") compared with two different reference scenarios that include the use of renewable fuels: a 2022 baseline projection based on the RFS1-mandated volume of 7.1 billion gallons of renewable fuels, and a 2022 baseline projection based on the AEO 2007 volume of roughly 13.6 billion gallons of renewable fuels.[TTTTTTTTTTTTT] Thus, the results represent the impact of an incremental increase in ethanol and other renewable fuels. We note that the air quality modeling results presented in this final rule do not constitute the "anti-backsliding" analysis required by Clean Air Act section 211(v). EPA will be analyzing air quality and health impacts of increased renewable fuel use through that study and will promulgate appropriate mitigation measures under section 211(v), separate from this final action.

As can be seen in Section 3.4 of this RIA, there are both increased and decreased concentrations of ambient criteria pollutants and air toxics. Overall, we estimate that the final rule will lead to a net increase in criteria pollutant-related health impacts. By 2022, the final RFS2 rule volumes relative to both reference case scenarios (RFS1 and AEO2007), are projected to adversely impact $PM_{2.5}$ air quality over parts of the U.S., while some areas will experience decreases in ambient $PM_{2.5}$. As described in Section 3.4, ambient $PM_{2.5}$ is likely to increase as a result of emissions at renewable fuel production plants and from renewable fuel transport, both of which are more prevalent in the Midwest. PM concentrations are also likely to decrease in some areas. While the PM-related air quality impacts are relatively small, the increase in population-weighted national average $PM_{2.5}$ exposure results in a net increase in adverse PM-related human health impacts. (the increase in national population weighted annual average

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[TTTTTTTTTTTTT] The 2022 modeled scenarios assume the following: RFS1 reference case assumes 6.7 Bgal/yr ethanol and 0.38 Bgal/yr biodiesel; AEO2007 reference case assumes 13.18 Bgal/yr ethanol and 0.38 Bgal/yr biodiesel; RFS2 control case assumes 34.14 Bgal/yr ethanol, 0.81 Bgal/yr biodiesel, and 0.38 Bgal/yr renewable diesel. Please refer to Chapter 3.3 and Table 3.3-1 for more information about the renewable fuel volumes assumed in the modeled analyses and the corresponding emissions inventories.

$PM_{2.5}$ is 0.006 μg/m3 and 0.002 μg/m3 relative to the RFS1 and AEO2007 reference cases, respectively).

The required renewable fuel volumes, relative to both reference scenarios, are also projected to adversely impact ozone air quality over much of the U.S., especially in the Midwest, Northeast and Southeast. These adverse impacts are likely due to increased upstream emissions of NOx in many areas that are NOx-limited (acting as a precursor to ozone formation). There are, however, ozone air quality improvements in some highly-populated areas that currently have poor air quality. This is likely due to VOC emission reductions at the tailpipe in urban areas that are VOC-limited (reducing VOC's role as a precursor to ozone formation). Relative to the RFS1 mandate reference case, the RFS2 volumes result in a small increase in ozone-related health impacts (population weighted maximum 8-hour average ozone increases by 0.177 ppb). Relative to the AEO2007 reference case, the RFS2 volumes result in a small increase in ozone-related health impacts (population weighted maximum 8-hour average ozone increases by 0.116 ppb).

The analysis of national-level $PM_{2.5}$- and ozone-related health and environmental impacts associated with the final rule is based on peer-reviewed studies of air quality and human health effects (see US EPA, 2006 and US EPA, 2008).[1180,1181] We are also consistent with the benefits analysis methods that supported the recently proposed Portland Cement National Emissions Standards for Hazardous Air Pollutants (NESHAP) RIA (U.S. EPA, 2009a),[1182] the proposed $NO_2$ primary NAAQS RIA (U.S. EPA, 2009b),[1183] and the proposed Category 3 Marine Diesel Engines RIA (U.S. EPA, 2009c).[1184] To model the ozone and PM air quality impacts of the 2022 renewable fuel volumes, we used the Community Multiscale Air Quality (CMAQ) model (see Chapter 3.4). The modeled ambient air quality data serves as an input to the Environmental Benefits Mapping and Analysis Program (BenMAP).[UUUUUUUUUUUUU] BenMAP is a computer program developed by the U.S. EPA that integrates a number of the modeling elements used in previous analyses (e.g., interpolation functions, population projections, health impact functions, valuation functions, analysis and pooling methods) to translate modeled air concentration estimates into health effects incidence estimates and monetized benefits estimates.

Emissions and air quality modeling decisions were made early in the analytical process and as a result, there are a number of important limitations and uncertainties associated with the air quality modeling analysis that must be kept in mind when considering the results. A key limitation of the analysis is that it employed interim emission inventories, which were enhanced compared to what was described in the proposal, but did not include some of the later enhancements and corrections of the final emission inventories presented in this FRM (see Section 3.3 of this RIA). Most significantly, our modeling of the air quality impacts of RFS2 relied upon interim inventories that assumed that ethanol will make up 34 of the 36 billion gallon renewable fuel mandate, that approximately 20 billion gallons of this ethanol will be in the form of E85, and that the use of E85 results in fewer emissions of direct $PM_{2.5}$ from vehicles. The emission impacts, air quality results and benefits analysis would be different if, instead of E85, more non-ethanol biofuels are used or mid-level ethanol blends are approved and utilized.
In fact, as explained in Chapter 1, our more recent analyses indicate that ethanol and E85 volumes are likely to be significantly lower than what we assumed in the interim inventories.

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[UUUUUUUUUUUUU] Information on BenMAP, including downloads of the software, can be found at http://www.epa.gov/ttn/ecas/ benmodels.html.

Furthermore, the final emission inventories do not include vehicle-related PM reductions associated with E85 use, as discussed in Chapters 3.1-3.3 of this RIA. There are additional, important limitations and uncertainties associated with the interim inventories that must be kept in mind when considering the results, which are described in more detail in Chapter 3.4. While it is difficult to describe the overall impact of these limitations and uncertainties on the quantified and monetized health impacts of the increased renewable fuel volumes without updating the air quality modeling analysis, we believe the results are still useful for describing potential national-level health impacts.

Additionally, after the air quality modeling was completed, we discovered an error in the way that $PM_{2.5}$ emissions from locomotive engines were allocated to counties in the inventory. The mismatched allocations between the reference and control scenarios resulted in $PM_{2.5}$ emission changes that were too high in some counties and too low in others, by varying degrees. As a result, we did not present the modeling results for specific localized $PM_{2.5}$ impacts in Section 3.4. However, because the error was random and offsetting, there was very little impact on national-level $PM_{2.5}$ emissions. An analysis of the error's impact on the national emission inventories found that direct $PM_{2.5}$ emissions were inflated by 8% relative to the AEO reference case and by 0.6% relative to the RFS1 reference case, leading to a small overestimation of national PM-related adverse health impacts. Note that this error did not impact other PM precursor inventories such as NOx and SO2. As a result, we have concluded that $PM_{2.5}$ modeling results are still informative for national-level benefits assessment, particularly given that other uncertainties in the $PM_{2.5}$ inventory (such as E85 usage**,** discussed below) have a more important (and offsetting) effect.

## Table 5.4-1.
## Estimated 2022 Monetized PM-and Ozone-Related Health Impacts from the Mandated Renewable Fuel Volumes[a]

2022 Total Ozone and PM Benefits, RFS2 Control Case Compared to RFS1 Reference Case[a]

| Premature Ozone Mortality Function | Reference | Total Benefits (Billions, 2007$, 3% Discount Rate)[b,c] | Total Benefits (Billions, 2007$, 7% Discount Rate) [b,c] |
|---|---|---|---|
| Multi-city analyses | Bell et al., 2004 | Total: -$1.4 to -$2.8<br>PM: -$0.92 to -$2.3<br>Ozone: -$0.52 | Total: -$1.4 to -$2.6<br>PM: -$0.84 to -$2.0<br>Ozone: -$0.52 |
| | Huang et al., 2005 | Total: -$1.8 to -$3.1<br>PM: -$0.92 to -$2.3<br>Ozone: -$0.83 | Total: -$1.7 to -$2.9<br>PM: -$0.84 to -$2.0<br>Ozone: -$0.83 |
| | Schwartz, 2005 | Total: -$1.7 to -$3.0<br>PM: -$0.92 to -$2.3<br>Ozone: -$0.77 | Total: -$1.6 to -$2.8<br>PM: -$0.84 to -$2.0<br>Ozone: -$0.77 |
| Meta-analyses | Bell et al., 2005 | Total: -$2.5 to -$3.8<br>PM: -$0.92 to -$2.3<br>Ozone: -$1.6 | Total: -$2.4 to -$3.6<br>PM: -$0.84 to -$2.0<br>Ozone: -$1.6 |
| | Ito et al., 2005 | Total: -$3.1 to -$4.5<br>PM: -$0.92 to -$2.3<br>Ozone: -$2.2 | Total: -$3.0 to -$4.2<br>PM: -$0.84 to -$2.0<br>Ozone: -$2.2 |
| | Levy et al., 2005 | Total: -$3.1 to -$4.5<br>PM: -$0.92 to -$2.3<br>Ozone: -$2.2 | Total: -$3.1 to -$4.3<br>PM: -$0.84 to -$2.0<br>Ozone: -$2.2 |

2022 Total Ozone and PM Benefits, RFS2 Control Case Compared to AEO Reference Case[a]

| Premature Ozone Mortality Function | Reference | Total Benefits (Millions, 2007$, 3% Discount Rate)[b,c] | Total Benefits (Millions, 2007$, 7% Discount Rate) [b,c] |
|---|---|---|---|
| Multi-city analyses | Bell et al., 2004 | Total: -$0.63 to -$1.0<br>PM: -$0.29 to -$0.70<br>Ozone: -$0.34 | Total: -$0.60 to -$0.98<br>PM: -$0.26 to -$0.63<br>Ozone: -$0.34 |
| | Huang et al., 2005 | Total: -$0.84 to -$1.3<br>PM: -$0.29 to -$0.70<br>Ozone: -$0.55 | Total: -$0.81 to -$1.2<br>PM: -$0.26 to -$0.63<br>Ozone: -$0.55 |
| | Schwartz, 2005 | Total: -$0.80 to -$1.2<br>PM: -$0.29 to -$0.70<br>Ozone: -$0.51 | Total: -$0.77 to -$1.1<br>PM: -$0.26 to -$0.63<br>Ozone: -$0.51 |
| Meta-analyses | Bell et al., 2005 | Total: -$1.3 to -$1.8<br>PM: -$0.29 to -$0.70<br>Ozone: -$1.0 | Total: -$1.3 to -$1.7<br>PM: -$0.26 to -$0.63<br>Ozone: -$1.0 |
| | Ito et al., 2005 | Total: -$1.7 to -$2.2<br>PM: -$0.29 to -$0.70<br>Ozone: -$1.5 | Total: -$1.7 to -$2.1<br>PM: -$0.26 to -$0.63<br>Ozone: -$1.5 |
| | Levy et al., 2005 | Total: -$1.8 to -$2.2<br>PM: -$0.29 to -$0.70<br>Ozone: -$1.5 | Total: -$1.7 to -$2.1<br>PM: -$0.26 to -$0.63<br>Ozone: -$1.5 |

[a] Total includes premature mortality-related and morbidity-related ozone and PM$_{2.5}$ benefits. Range was developed by adding the estimate from the ozone premature mortality function to the estimate of PM$_{2.5}$-related premature mortality derived from either the ACS study (Pope et al., 2002) or the Six-Cities study (Laden et al., 2006).

[b] Note that total benefits presented here do not include a number of unquantified benefits categories. A detailed listing of unquantified health and welfare effects is provided in Table 5.4-2.

[c] Results reflect the use of both a 3 and 7 percent discount rate, as recommended by EPA's Guidelines for Preparing Economic Analyses and OMB Circular A-4. Results are rounded to two significant digits for ease of presentation and computation.

The monetized estimates in Table 5.4-1 include all of the human health impacts we are able to quantify and monetize at this time. However, the full complement of human health and welfare effects associated with PM and ozone remain unquantified because of current limitations in methods or available data. We have not quantified a number of known or suspected health effects linked with ozone and PM for which appropriate health impact functions are not available or which do not provide easily interpretable outcomes (i.e., changes in heart rate variability). Additionally, we are unable to quantify a number of known welfare effects, including acid and particulate deposition damage to cultural monuments and other materials, and environmental impacts of eutrophication in coastal areas. These are listed in Table 5.4-2.

## Table 5.4-2.
## Unquantified and Non-Monetized Potential Effects from the Mandated Renewable Fuel Volumes

| POLLUTANT/EFFECTS | EFFECTS NOT INCLUDED IN ANALYSIS - CHANGES IN: |
|---|---|
| Ozone Health[a] | Chronic respiratory damage[b]<br>Premature aging of the lungs[b]<br>Non-asthma respiratory emergency room visits<br>Exposure to UVb (+/-)[e] |
| Ozone Welfare | Yields for<br>-commercial forests<br>-some fruits and vegetables<br>-non-commercial crops<br>Damage to urban ornamental plants<br>Impacts on recreational demand from damaged forest aesthetics<br>Ecosystem functions<br>Exposure to UVb (+/-)[e] |
| PM Health[c] | Premature mortality - short term exposures[d]<br>Low birth weight<br>Pulmonary function<br>Chronic respiratory diseases other than chronic bronchitis<br>Non-asthma respiratory emergency room visits<br>Exposure to UVb (+/-)[e] |
| PM Welfare | Residential and recreational visibility in non-Class I areas<br>Soiling and materials damage<br>Damage to ecosystem functions<br>Exposure to UVb (+/-)[e] |
| Nitrogen and Sulfate Deposition Welfare | Commercial forests due to acidic sulfate and nitrate deposition<br>Commercial freshwater fishing due to acidic deposition<br>Recreation in terrestrial ecosystems due to acidic deposition<br>Existence values for currently healthy ecosystems<br>Commercial fishing, agriculture, and forests due to nitrogen deposition<br>Recreation in estuarine ecosystems due to nitrogen deposition<br>Ecosystem functions<br>Passive fertilization |
| CO Health | Behavioral effects |
| HC/Toxics Health[f] | Cancer (benzene, 1,3-butadiene, formaldehyde, acetaldehyde)<br>Anemia (benzene)<br>Disruption of production of blood components (benzene)<br>Reduction in the number of blood platelets (benzene)<br>Excessive bone marrow formation (benzene)<br>Depression of lymphocyte counts (benzene)<br>Reproductive and developmental effects (1,3-butadiene)<br>Irritation of eyes and mucus membranes (formaldehyde)<br>Respiratory irritation (formaldehyde)<br>Asthma attacks in asthmatics (formaldehyde)<br>Asthma-like symptoms in non-asthmatics (formaldehyde)<br>Irritation of the eyes, skin, and respiratory tract (acetaldehyde)<br>Upper respiratory tract irritation and congestion (acrolein) |
| HC/Toxics Welfare | Direct toxic effects to animals<br>Bioaccumulation in the food chain<br>Damage to ecosystem function<br>Odor |

[a] The public health impact of biological responses such as increased airway responsiveness to stimuli, inflammation in the lung, acute inflammation and respiratory cell damage, and increased susceptibility to respiratory infection are likely partially represented by our quantified endpoints.
[b] The public health impact of effects such as chronic respiratory damage and premature aging of the lungs may be partially represented by quantified endpoints such as hospital admissions or premature mortality, but a number of other related health impacts, such as doctor visits and decreased athletic performance, remain unquantified.
[c] In addition to primary economic endpoints, there are a number of biological responses that have been associated with PM health effects including morphological changes and altered host defense mechanisms. The public health impact of these biological responses may be partly represented by our quantified endpoints.
[d] While some of the effects of short-term exposures are likely to be captured in the estimates, there may be premature mortality due to short-term exposure to PM not captured in the cohort studies used in this analysis. However, the PM mortality results derived from the expert elicitation do take into account premature mortality effects of short term exposures.
[e] May result in benefits or adverse impacts.
[f] Many of the key hydrocarbons related to this rule are also hazardous air pollutants listed in the Clean Air Act.

While there will be impacts associated with air toxic pollutant emission changes that result from the increased use of renewable fuels, we do not attempt to monetize those impacts. This is primarily because currently available tools and methods to assess air toxics risk from mobile sources at the national scale are not adequate for extrapolation to incidence estimations or benefits assessment. The best suite of tools and methods currently available for assessment at the national scale are those used in the National-Scale Air Toxics Assessment (NATA). The EPA Science Advisory Board specifically commented in their review of the 1996 NATA that these tools were not yet ready for use in a national-scale benefits analysis, because they did not consider the full distribution of exposure and risk, or address sub-chronic health effects.[vvvvvvvvvvvvv] While EPA has since improved the tools, there remain critical limitations for estimating incidence and assessing benefits of reducing mobile source air toxics. EPA continues to work to address these limitations; however, we did not have the methods and tools available for national-scale application in time for the analysis of the final rule.[wwwwwwwwwwwww]

### 5.4.2 Quantified Human Health Impacts

Tables 5.4-3 and 5.4-4 present the annual $PM_{2.5}$ and ozone health impacts in the 48 contiguous U.S. states associated with the RFS2 volumes relative to both the RFS1 and AEO reference cases for 2022. For each endpoint presented in Tables 5.4-3 and 5.4-4, we provide both the mean estimate and the 90% confidence interval.

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[vvvvvvvvvvvvv] Science Advisory Board. 2001. NATA – Evaluating the National-Scale Air Toxics Assessment for 1996 – an SAB Advisory. http://www.epa.gov/ttn/atw/sab/sabrev.html.

[wwwwwwwwwwwww] In April, 2009, EPA hosted a workshop on estimating the benefits or reducing hazardous air pollutants. This workshop built upon the work accomplished in the June 2000 Science Advisory Board/EPA Workshop on the Benefits of Reductions in Exposure to Hazardous Air Pollutants, which generated thoughtful discussion on approaches to estimating human health benefits from reductions in air toxics exposure, but no consensus was reached on methods that could be implemented in the near term for a broad selection of air toxics. Please visit http://epa.gov/air/toxicair/2009workshop.html for more information about the workshop and its associated materials.

Using EPA's preferred estimates, based on the ACS and Six-Cities studies and no threshold assumption in the model of mortality, we estimate that the RFS2 volumes will result in between 110 and 270 cases of $PM_{2.5}$-related premature deaths annually in 2022 when compared to the RFS1 reference case. When compared to the AEO reference scenario, we estimate that the RFS2 volumes will result in between 33 and 85 cases of avoided $PM_{2.5}$-related premature deaths annually in 2022. As a sensitivity analysis, when the range of expert opinion is used we estimate that in 2022 the RFS2 volumes will result in between 34 and 360 PM-related premature mortalities when compared to the RFS1 reference case and between 11 and 110 PM-related premature mortalities when compared to the AEO reference case.

The range of ozone impacts associated with the RFS2 volumes is based on changes in risk estimated using several sources of ozone-related mortality effect estimates. This analysis presents six alternative estimates for the association based upon different functions reported in the scientific literature, derived from both multi-city studies, such as the National Morbidity, Mortality, and Air Pollution Study (NMMAPS) (Bell et al., 2004, Huang et al., 2005, and Schwartz et al., 2005) and from a series of recent meta-analyses (Bell et al., 2005, Ito et al., 2005, and Levy et al., 2005). This approach is not inconsistent with recommendations provided by the NRC in their recent report (NRC, 2008) on the estimation of ozone-related mortality risk, "The committee recommends that the greatest emphasis be placed on estimates from new systematic multicity analyses that use national databases of air pollution and mortality, such as in the NMMAPS, without excluding consideration of meta-analyses of previously published studies." For ozone-related premature mortality, we estimate that national changes in ambient ozone will contribute to between 54 to 250 additional premature mortalities in 2022 as a result of the RFS2 volumes relative to the RFS1 scenario. When compared to the AEO reference scenario, we estimate that the RFS2 volumes will contribute to between 36 to 160 additional ozone-related premature mortalities in 2022.

Following these tables, we also provide a more comprehensive presentation of the distributions of mortality-related incidence generated using the available information from empirical studies and expert elicitation associated with the RFS2 volumes compared to each reference scenario. Tables 5.4-5 and 5.4-6 present the distributions of $PM_{2.5}$-related premature mortality based on the C-R distributions provided by each expert, as well as that from the data-derived health impact functions, based on the statistical error associated with the ACS study (Pope et al., 2002) and the Six-cities study (Laden et al., 2006). The 90% confidence interval for each separate estimate of PM-related mortality is also provided.

When comparing the RFS2 fuel volume scenario to the RFS1 reference case, the effect estimates of nine of the twelve experts included in the elicitation panel fall within the empirically-derived range provided by the ACS and Six-Cities studies. Only one expert falls below this range, while two of the experts are above this range. This same relationship occurs when comparing the RFS2 fuel volume scenario to the AEO reference case. Although the overall range across experts is summarized in these tables, the full uncertainty in the estimates is reflected by the results for the full set of 12 experts. The twelve experts' judgments as to the likely mean effect estimate are not evenly distributed across the range illustrated by arraying the highest and lowest expert means.

# Table 5.4-3.
# Estimated $PM_{2.5}$-Related Health Impacts Associated with the Mandated Renewable Fuel Volumes[a]

| Health Effect | 2022 RFS2 Control Case Compared to RFS1 Reference Case (5th% - 95th%ile) | 2022 RFS2 Control Case Compared to AEO Reference Case (5th% - 95th%ile) |
|---|---|---|
| Premature Mortality – Derived from Epidemiology Literature[b] | | |
| Adult, age 30+, ACS Cohort Study (Pope et al., 2002) | -110<br>(-42 - -170) | -33<br>(-13 - -53) |
| Adult, age 25+, Six-Cities Study (Laden et al., 2006) | -270<br>(-150 - -400) | -85<br>(-46 - -120) |
| Infant, age <1 year (Woodruff et al., 1997) | 0<br>(0 - -1) | 0<br>(0 - -1) |
| Chronic bronchitis (adult, age 26 and over) | -65<br>(-26 - -110) | -19<br>(-4 - -18) |
| Non-fatal myocardial infarction (adult, age 18 and over | -180<br>(-65 - -290) | -51<br>(-19 - -84) |
| Hospital admissions - respiratory (all ages)[c] | -26<br>(-25 - -26) | -7<br>(-5 - -8) |
| Hospital admissions - cardiovascular (adults, age >18)[d] | -55<br>(-44 - -70) | -12<br>(-9 - -16) |
| Emergency room visits for asthma (age 18 years and younger) | -180<br>(-110 - -260) | -99<br>(-58 - -140) |
| Acute bronchitis, (children, age 8-12) | -160<br>(0 - -330) | -50<br>(0 - -100) |
| Lower respiratory symptoms (children, age 7-14) | -1,900<br>(-910 - -2,900) | -600<br>(-290 - -910) |
| Upper respiratory symptoms (asthmatic children, age 9-18) | -1,400<br>(-450 - -2,400) | -450<br>(-140 - -750) |
| Asthma exacerbation (asthmatic children, age 6-18) | -1,700<br>(-190 - -4,800) | -540<br>(-60 - -1,500) |
| Work loss days | -11,000<br>(-10,000 - -13,000) | -3,200<br>(-2,800 - -3,700) |
| Minor restricted activity days (adults age 18-65) | -68,000<br>(-57,000 - -78,000) | -19,000<br>(-16,000 - -22,000) |

[a] Note that negative incidence expressed in this table reflects “disbenefits”; in other words, an increase in total aggregated national-level ozone-related health impacts. Incidence is rounded to two significant digits. Estimates represent incidence within the 48 contiguous United States.

[b] PM-related adult mortality based upon the American Cancer Society (ACS) Cohort Study (Pope et al., 2002) and the Six-Cities Study (Laden et al., 2006). Note that these are two alternative estimates of adult mortality and should not be summed. PM-related infant mortality based upon a study by Woodruff, Grillo, and Schoendorf, (1997).[xxxxxxxxxxxxx]

[c] Respiratory hospital admissions for PM include admissions for chronic obstructive pulmonary disease (COPD), pneumonia and asthma.

[d] Cardiovascular hospital admissions for PM include total cardiovascular and subcategories for ischemic heart disease, dysrhythmias, and heart failure.

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[xxxxxxxxxxxxx] Woodruff, T.J., J. Grillo, and K.C. Schoendorf. 1997. “The Relationship Between Selected Causes of Postneonatal Infant Mortality and Particulate Air Pollution in the United States.” *Environmental Health Perspectives* 105(6):608-612.

## Table 5.4-4.
## Estimated Ozone-Related Health Impacts Associated with the Mandated Renewable Fuel Volumes[a]

| Health Effect | 2022 RFS2 Control Case Compared to RFS1 Reference Case ($5^{th}$% - $95^{th}$%ile) | 2022 RFS2 Control Case compared to AEO Reference Case ($5^{th}$% - $95^{th}$%ile) |
|---|---|---|
| Premature Mortality, All ages[b] | | |
| Multi-City Analyses | | |
| Bell et al. (2004) – Non-accidental | -54<br>(-17 - -92) | -36<br>(-10 - -62) |
| Huang et al. (2005) – Cardiopulmonary | -90<br>(-31 - -149) | -59<br>(-18 - -100) |
| Schwartz (2005) – Non-accidental | -83<br>(-24 - -140) | -55<br>(-13 - -97) |
| Meta-analyses: | | |
| Bell et al. (2005) – All cause | -180<br>(-80 - -270) | -120<br>(-49 - -180) |
| Ito et al. (2005) – Non-accidental | -240<br>(-140 - -350) | -160<br>(-90 - -230) |
| Levy et al. (2005) – All cause | -250<br>(-170 - -330) | -160<br>(-110 - -220) |
| Hospital admissions- respiratory causes (adult, 6 and older)[c] | -470<br>(-20 - -860) | -310<br>(-5 - -580) |
| Hospital admissions -respiratory causes (children under 2) | -83<br>(-24 - -140) | -190<br>(-52 - -330) |
| Emergency room visit for asthma (all ages) | -260<br>(0 - -740) | -180<br>(0 - -510) |
| Minor restricted activity days (adults, age 18-65) | -300,000<br>(-110,000 - -500,000) | -200,000<br>(-59,000 - -340,000) |
| School absence days | -110,000<br>(-35,000 - -180,000) | -75,000<br>(-19,000 - -120,000) |

[a] Note that negative incidence expressed in this table reflects "disbenefits"; in other words, an increase in total aggregated national-level ozone-related health impacts. Incidence is rounded to two significant digits. Estimates represent incidence within the 48 contiguous United States. Note that negative incidence estimates represent additional cases of an endpoint related to pollution increases associated with the rule.

[b] Estimates of ozone-related premature mortality are based upon incidence estimates derived from several alternative studies: Bell et al. (2004); Huang et al. (2005); Schwartz (2005) ; Bell et al. (2005); Ito et al. (2005); Levy et al. (2005). The estimates of ozone-related premature mortality should therefore not be summed.

[c] Respiratory hospital admissions for ozone include admissions for all respiratory causes and subcategories for COPD and pneumonia.

## Table 5.4-5. Results of Application of Expert Elicitation: Annual Reductions in Premature Mortality in 2022 Associated with the Mandated Renewable Fuel Volumes

| Source of Mortality Estimate | 2022 RFS2 Control Case Compared to the RFS1 Reference Case | | |
|---|---|---|---|
| | 5th Percentile | Mean | 95th Percentile |
| Pope et al. (2002) | -42 | -110 | -170 |
| Laden et al. (2006) | -150 | -270 | -400 |
| Expert A | -53 | -290 | -530 |
| Expert B | -11 | -210 | -480 |
| Expert C | -39 | -220 | -470 |
| Expert D | -32 | -150 | -250 |
| Expert E | -180 | -360 | -550 |
| Expert F | -130 | -200 | -260 |
| Expert G | 0 | -130 | -240 |
| Expert H | -1 | -160 | -380 |
| Expert I | -34 | -220 | -390 |
| Expert J | -52 | -180 | -390 |
| Expert K | 9 | -34 | -180 |
| Expert L | 4 | -130 | -310 |

## Table 5.4-6. Results of Application of Expert Elicitation: Annual Reductions in Premature Mortality in 2022 Associated with the Mandated Renewable Fuel Volumes

| Source of Mortality Estimate | 2022 RFS2 Control Case Compared to the AEO Reference Case | | |
|---|---|---|---|
| | 5th Percentile | Mean | 95th Percentile |
| Pope et al. (2002) | -13 | -33 | -53 |
| Laden et al. (2006) | -46 | -85 | -120 |
| Expert A | -17 | -91 | -170 |
| Expert B | 7 | -65 | -160 |
| Expert C | -12 | -68 | -150 |
| Expert D | -10 | -48 | -79 |
| Expert E | -57 | -110 | -170 |
| Expert F | -35 | -59 | -69 |
| Expert G | 0 | -40 | -74 |
| Expert H | 0 | -51 | -120 |
| Expert I | -11 | -68 | -121 |
| Expert J | -16 | -55 | -122 |
| Expert K | 0 | -11 | -54 |
| Expert L | 8 | -38 | -101 |

### 5.4.3 Monetized Benefits

Monetized values for each quantified health endpoint are presented in Table 5.4-7. For each endpoint presented in Table 5.4-7, we provide both the mean estimate and the 90% confidence interval. Total aggregate monetized benefits are presented in Tables 5.4-8 and 5.4-9 using either a 3 percent or 7 percent discount rate, respectively. All of the monetary benefits are in constant-year 2007 dollars.

In addition to omitted benefits categories such as air toxics and various welfare effects, not all known $PM_{2.5}$- and ozone-related health and welfare effects could be quantified or monetized. The estimate of total monetized health impacts from the renewable fuel volumes are thus equal to the subset of monetized $PM_{2.5}$- and ozone-related health impacts we are able to quantify plus the sum of the nonmonetized health and welfare impacts.

Our estimate of monetized adverse health impacts in 2022 for the RFS2 fuel volume scenario compared to the RFS1 reference case, using the ACS and Six-Cities PM mortality studies and the range of ozone mortality assumptions, is between \$1.4 billion and \$4.5 billion, assuming a 3 percent discount rate, or between \$1.4 billion and \$4.3 billion, assuming a 7 percent discount rate. When compared to the AEO reference case, we estimate the monetized adverse health impacts to be between \$0.63 billion and \$2.2 billion, assuming a 3 percent discount rate, or between \$0.60 billion and \$2.1 billion, assuming a 7 percent discount rate. The monetized impacts associated with an increase in the risk of both ozone- and $PM_{2.5}$-related premature mortality ranges between 90 to 98 percent of total monetized health impacts, in part because we are unable to quantify a number of health and environmental impact categories (see Table 5.4-2). These unquantified impacts may be substantial, although their magnitude is highly uncertain.

The next largest adverse health impact is for increased incidence of PM-related chronic illness (chronic bronchitis and nonfatal heart attacks), although this value is more than an order of magnitude lower than for PM-related premature mortality. Hospital admissions for respiratory and cardiovascular causes, minor restricted activity days, and work loss days account for the majority of the remaining adverse health impacts. The remaining categories each account for a small percentage of total adverse health impacts. A comparison of the incidence table to the monetized health impacts table reveals that there is not always a close correspondence between the number of incidences for a given endpoint and the monetary value associated with that endpoint. For example, there are over 100 times more work loss days than PM-related premature mortalities (based on the ACS study), yet work loss days account for only a very small fraction of total monetized adverse health impacts. This reflects the fact that many of the less severe health effects, while more common, are valued at a lower level than the more severe health effects. Also, some effects, such as hospital admissions, are valued using a proxy measure of willingness-to-pay (e.g., cost-of-illness). As such, the true value of these effects may be different than that reported here.

## Table 5.4-7.
## Estimated Monetary Value of Health and Welfare Effect Incidence (in millions of 2007$)[a,b]

| | | 2022 RFS2 Control Case Compared to RFS1 Reference Case | 2022 RFS2 Control Case Compared to AEO Reference Case |
|---|---|---|---|
| **PM$_{2.5}$-Related Health Effect** | | Estimated Mean Value of Reductions (5th and 95th %ile) | |
| Premature Mortality – Derived from Epidemiology Studies[c,d,] | Adult, age 30+ - ACS study (Pope et al., 2002)<br>3% discount rate<br>7% discount rate | -$860<br>(-$100 - -$2,300)<br>-$770<br>(-$91 - -$2,000) | -$270<br>(-$32 - -$700)<br>-$240<br>(-$28 - -$630) |
| | Adult, age 25+ - Six-cities study (Laden et al., 2006)<br>3% discount rate<br>7% discount rate | -$2,200<br>(-$29 - -$5,500)<br>-$2,000<br>(-$26 - -$5,000) | -$680<br>(-$90 - -$1,700)<br>-$620<br>(-$81 - -$1,600) |
| | Infant Mortality, <1 year – (Woodruff et al. 1997) | -$4.0<br>(-$3.0 - -$15) | -$1.7<br>(-$1.3 - -$6.7) |
| Chronic bronchitis (adults, 26 and over) | | -$32<br>(-$2.5 - -$110) | -$9.4<br>(-$0.72 - -$33) |
| Non-fatal acute myocardial infarctions<br>3% discount rate<br>7% discount rate | | -$23<br>(-$4.1 - -$58)<br>-$23<br>(-$3.8 - -$58) | -$6.6<br>(-$1.0 - -$17)<br>-$6.4<br>(-$0.95 - -$16) |
| Hospital admissions for respiratory causes | | -$0.39<br>(-$0.19 - -$0.57 | -$0.11<br>(-$0.06 - -$0.17) |
| Hospital admissions for cardiovascular causes | | -$1.5<br>(-$0.96 - -$2.1) | -$0.33<br>(-$0.20 - -$0.45) |
| Emergency room visits for asthma | | -$0.07<br>(-$0.04 - -$0.10) | -$0.04<br>(-$0.02 - -$0.06) |
| Acute bronchitis (children, age 8–12) | | -$0.01<br>($0 - -$0.03) | -$0.004<br>($0 - -$0.01) |
| Lower respiratory symptoms (children, 7–14) | | -$0.04<br>(-$0.01 - -$0.07) | -$0.01<br>(-$0.004 - -$0.02) |
| Upper respiratory symptoms (asthma, 9–11) | | -$0.04<br>(-$0.01 - -$0.10) | -$0.01<br>(-$0.004 - -$0.03) |
| Asthma exacerbations | | -$0.09<br>(-$0.009 - -$0.28) | -$0.03<br>(-$0.003 - -$0.09) |
| Work loss days | | -$1.7<br>(-$1.5 - -$1.9) | -$0.49<br>(-$0.42 - -$0.55) |
| Minor restricted-activity days (MRADs) | | -$4.3<br>(-$2.5 - -$6.2) | -$1.2<br>(-$0.69 - -$1.7) |
| **Ozone-related Health Effect** | | | |
| Premature Mortality, All ages – Derived from Multi-city analyses | Bell et al., 2004 | -$480<br>(-$51 - -$1,300) | -$320<br>(-$32 - -$880) |
| | Huang et al., 2005 | -$800<br>(-$90 - -$2,200) | -$530<br>(-$56 - -$1,400) |

|  |  |  |  |
|---|---|---|---|
|  | Schwartz, 2005 | -$740<br>(-$76 - -$2,000) | -$490<br>(-$48 - -$1,300) |
| Premature Mortality, All ages – Derived from Meta-analyses | Bell et al., 2005 | -$1,600<br>(-$200 - -$4,000) | -$1,000<br>(-$130 - -$,700) |
|  | Ito et al., 2005 | -$2,200<br>(-$290 - -$5,400) | -$1,400<br>(-$190 - -$3,600) |
|  | Levy et al., 2005 | -$2,200<br>(-$300 - -$5,300) | -$1,400<br>(-$200 - -$3,500) |
| Hospital admissions- respiratory causes (adult, 65 and older) |  | -$11<br>(-$0.49 - -$20) | -$7.4<br>(-$0.13 - -$14) |
| Hospital admissions- respiratory causes (children, under 2) |  | -$3.0<br>(-$1.0 - -$4,9) | -$1.9<br>(-$0.52 - -$3.3) |
| Emergency room visit for asthma (all ages) |  | -$0.10<br>(-$0.009 - -$0.26) | -$0.07<br>(-$0.008 - -$0.18) |
| Minor restricted activity days (adults, age 18-65) |  | -$19<br>(-$6.4 - -$35) | -$13<br>(-$3.6 - -$24) |
| School absence days |  | -$10<br>(-$3.1 - -$16) | -$6.7<br>(-$1.7 - -$11) |

[a] Negatives indicate a disbenefit, or an increase in health effect incidence. Monetary impacts are rounded to two significant digits for ease of presentation and computation. PM and ozone impacts are nationwide.

[b] Monetary impacts adjusted to account for growth in real GDP per capita between 1990 and the analysis year (2022)

[c] Valuation assumes discounting over the SAB recommended 20 year segmented lag structure. Results reflect the use of 3 percent and 7 percent discount rates consistent with EPA and OMB guidelines for preparing economic analyses.

### Table 5.4-8. Total Monetized Impacts Associated with the Mandated Renewable Fuel Volumes – 3% Discount Rate

| **Total Ozone and PM Monetized Impacts (billions, 2007$) –PM Mortality Derived from the ACS and Six Cities Studies** | | | | | |
|---|---|---|---|---|---|
| **2022 RFS2 Control Case Compared to RFS1 Reference Case** | | | **2022 RFS2 Control Case Compared to AEO Reference Case** | | |
| Ozone Mortality Function | Reference | Mean Total Benefits | Ozone Mortality Function | Reference | Mean Total Benefits |
| Multi-city | Bell et al., 2004 | -$1.4 to -$2.8 | Multi-city | Bell et al., 2004 | -$1.3 to -$1.8 |
| | Huang et al., 2005 | -$1.8 to -$3.1 | | Huang et al., 2005 | -$0.84 to -$1.3 |
| | Schwartz, 2005 | -$1.7 to -$3.0 | | Schwartz, 2005 | -$0.80 to -$1.2 |
| Meta-analysis | Bell et al., 2005 | -$2.5 to -$3.8 | Meta-analysis | Bell et al., 2005 | -$1.3 to -$1.8 |
| | Ito et al., 2005 | -$3.1 to -$4.5 | | Ito et al., 2005 | -$1.7 to -$2.2 |
| | Levy et al., 2005 | -$3.1 to -$4.5 | | Levy et al., 2005 | -$1.8 to -$2.2 |
| **Total Ozone and PM Monetized Impacts (millions, 2007$) – PM Mortality Derived from Expert Elicitation (Lowest and Highest Estimate)** | | | | | |
| **2022 RFS2 Control Case Compared to RFS1 Reference Case** | | | **2022 RFS2 Control Case Compared to AEO Reference Case** | | |
| Ozone Mortality Function | Reference | Mean Total Benefits | Ozone Mortality Function | Reference | Mean Total Benefits |
| Multi-city | Bell et al., 2004 | -$0.86 to -$3.5 | Multi-city | Bell et al., 2004 | -$0.45 to -$1.3 |
| | Huang et al., 2005 | -$1.2 to -$3.8 | | Huang et al., 2005 | -$0.66 to -$1.5 |
| | Schwartz, 2005 | -$1.1 to -$3.8 | | Schwartz, 2005 | -$0.62 to -$1.4 |
| Meta-analysis | Bell et al., 2005 | -$1.9 to -$4.6 | Meta-analysis | Bell et al., 2005 | -$1.2 to -$2.0 |
| | Ito et al., 2005 | -$2.5 to -$5.2 | | Ito et al., 2005 | -$1.6 to -$2.4 |
| | Levy et al., 2005 | -$2.6 to -$5.2 | | Levy et al., 2005 | -$1.6 to -$2.4 |

### Table 5.4-9. Total Monetized Impacts Associated with the Mandated Renewable Fuel Volumes – 7% Discount Rate

| **Total Ozone and PM Monetized Impacts (billions, 2007$) – PM Mortality Derived from the ACS and Six Cities Studies** | | | | | |
|---|---|---|---|---|---|
| **2022 RFS2 Control Case Compared to RFS1 Reference Case** | | | **2022 RFS2 Control Case Compared to AEO Reference Case** | | |
| Ozone Mortality Function | Reference | Mean Total Benefits | Ozone Mortality Function | Reference | Mean Total Benefits |
| Multi-city | Bell et al., 2004 | -$1.4 to -$2.6 | Multi-city | Bell et al., 2004 | -$0.60 to -$0.98 |
| | Huang et al., 2005 | -$1.7 to -$2.9 | | Huang et al., 2005 | -$0.81 to -$1.2 |
| | Schwartz, 2005 | -$1.6 to -$2.8 | | Schwartz, 2005 | -$0.77 to -$1.1 |
| Meta-analysis | Bell et al., 2005 | -$2.4 to -$3.6 | Meta-analysis | Bell et al., 2005 | -$1.3 to -$1.7 |
| | Ito et al., 2005 | -$3.0 to -$4.2 | | Ito et al., 2005 | -$1.7 to -$2.1 |
| | Levy et al., 2005 | -$3.1 to -$4.3 | | Levy et al., 2005 | -$1.7 to -$2.1 |
| **Total Ozone and PM Monetized Impacts (millions, 2007$) – PM Mortality Derived from Expert Elicitation (Lowest and Highest Estimate)** | | | | | |
| **2022 RFS2 Control Case Compared to RFS1 Reference Case** | | | **2022 RFS2 Control Case Compared to AEO Reference Case** | | |
| Ozone Mortality Function | Reference | Mean Total Benefits | Ozone Mortality Function | Reference | Mean Total Benefits |
| Multi-city | Bell et al., 2004 | -$0.83 to -$3.5 | Multi-city | Bell et al., 2004 | -$0.44 to -$1.2 |
| | Huang et al., 2005 | -$1.1 to -$3.5 | | Huang et al., 2005 | -$0.65 to -$1.4 |
| | Schwartz, 2005 | -$1.1 to -$3.5 | | Schwartz, 2005 | -$0.61 to -$1.4 |
| Meta-analysis | Bell et al., 2005 | -$1.9 to -$4.3 | Meta-analysis | Bell et al., 2005 | -$1.1 to -$1.9 |
| | Ito et al., 2005 | -$2.5 to -$4.9 | | Ito et al., 2005 | -$1.6 to -$2.3 |
| | Levy et al., 2005 | -$2.5 to -$4.9 | | Levy et al., 2005 | -$1.6 to -$2.3 |

## 5.4.4 Methodology

### Human Health Impact Functions

Health impact functions measure the change in a health endpoint of interest, such as hospital admissions, for a given change in ambient ozone or PM concentration. Health impact functions are derived from primary epidemiology studies, meta-analyses of multiple epidemiology studies, or expert elicitations. A standard health impact function has four components: 1) an effect estimate from a particular study; 2) a baseline incidence rate for the health effect (obtained from either the epidemiology study or a source of public health statistics such as the Centers for Disease Control); 3) the size of the potentially affected population; and 4) the estimated change in the relevant ozone or PM summary measures.

A typical health impact function might look like:

$$\Delta y = y_0 \cdot \left(e^{\beta \cdot \Delta x} - 1\right),$$

where $y_0$ is the baseline incidence (the product of the baseline incidence rate times the potentially affected population), β is the effect estimate, and Δx is the estimated change in the summary pollutant measure. There are other functional forms, but the basic elements remain the same. The following subsections describe: the size of the potentially affected populations; the $PM_{2.5}$ and ozone effect estimates; and the treatment of potential thresholds in $PM_{2.5}$-related health impact functions. Chapter 5.4.6 describes the ozone and PM air quality inputs to the health impact functions.

### Potentially Affected Populations

The starting point for estimating the size of potentially affected populations is the 2000 U.S. Census block level dataset.[1185] The Benefits Modeling and Analysis Program (BenMAP) incorporates 250 age/gender/race categories to match specific populations potentially affected by ozone and other air pollutants. The software constructs specific populations matching the populations in each epidemiological study by accessing the appropriate age-specific populations from the overall population database. BenMAP projects populations to 2022 using growth factors based on economic projections.[1186]

### Effect Estimate Sources

The most significant quantifiable impacts of exposure to ambient concentrations of ozone and PM are attributable to human health risks. EPA's Ozone and PM Criteria Documents[1187,1188] and the World Health Organization's 2003 and 2004[1189,1190] reports outline numerous human health effects known or suspected to be linked to exposure to ambient ozone and PM. US EPA recently evaluated the ozone and PM literature for use in the benefits analysis for the final 2008 Ozone NAAQS and final 2006 PM NAAQS analyses. We use the same literature in this analysis; for more information on the studies that underlie the health impacts quantified in this RIA, please refer to those documents.

It is important to note that we are unable to separately quantify all of the possible PM and ozone health effects that have been reported in the literature for three reasons: (1) the possibility of double counting (such as hospital admissions for specific respiratory diseases versus hospital admissions for all or a sub-set of respiratory diseases); (2) uncertainties in applying effect relationships that are based on clinical studies to the potentially affected population; or (3) the lack of an established concentration-response (CR) relationship. Table 5.4-10 lists the health endpoints included in this analysis.

## Table 5.4-10. Ozone- and PM-Related Health Endpoints

| Endpoint | Pollutant | Study | Study Population |
|---|---|---|---|
| **Premature Mortality** | | | |
| Premature mortality – daily time series | O3 | Multi-city<br>Bell et al (2004) (NMMAPS study)1191 – Non-accidental<br>Huang et al (2005)1192 - Cardiopulmonary<br>Schwartz (2005)1193 – Non-accidental<br>Meta-analyses:<br>Bell et al (2005)1194 – All cause<br>Ito et al (2005)1195 – Non-accidental<br>Levy et al (2005)1196 – All cause | All ages |
| Premature mortality — cohort study, all-cause | PM2.5 | Pope et al. (2002)1197<br>Laden et al. (2006)1198 | >29 years<br>>25 years |
| Premature mortality, total exposures | PM2.5 | Expert Elicitation (IEc, 2006)1199 | >24 years |
| Premature mortality — all-cause | PM2.5 | Woodruff et al. (1997)1200 | Infant (<1 year) |
| Chronic Illness | | | |
| Chronic bronchitis | PM2.5 | Abbey et al. (1995)1201 | >26 years |
| Nonfatal heart attacks | PM2.5 | Peters et al. (2001)1202 | Adults (>18 years) |
| **Hospital Admissions** | | | |
| Respiratory | O3 | Pooled estimate:<br>Schwartz (1995) - ICD 460-519 (all resp)1203<br>Schwartz (1994a; 1994b) - ICD 480-486 (pneumonia)1204,1205<br>Moolgavkar et al. (1997) - ICD 480-487 (pneumonia)1206<br>Schwartz (1994b) - ICD 491-492, 494-496 (COPD)<br>Moolgavkar et al. (1997) – ICD 490-496 (COPD) | >64 years |
| | | Burnett et al. (2001)1207 | <2 years |
| | PM2.5 | Pooled estimate:<br>Moolgavkar (2003)—ICD 490-496 (COPD)1208<br>Ito (2003)—ICD 490-496 (COPD)1209 | >64 years |
| | PM2.5 | Moolgavkar (2000)—ICD 490-496 (COPD)1210 | 20–64 years |
| | PM2.5 | Ito (2003)—ICD 480-486 (pneumonia) | >64 years |
| | PM2.5 | Sheppard (2003)—ICD 493 (asthma)1211 | <65 years |
| Cardiovascular | PM2.5 | Pooled estimate:<br>Moolgavkar (2003)—ICD 390-429 (all cardiovascular)<br>Ito (2003)—ICD 410-414, 427-428 (ischemic heart disease, dysrhythmia, heart failure) | >64 years |
| | PM2.5 | Moolgavkar (2000)—ICD 390-429 (all cardiovascular) | 20–64 years |
| Asthma-related ER visits | O3 | Pooled estimate:<br>Jaffe et al (2003)1212<br>Peel et al (2005)1213<br>Wilson et al (2005)1214 | 5–34 years<br>All ages<br>All ages |
| Asthma-related ER visits (con't) | PM2.5 | Norris et al. (1999)1215 | 0–18 years |

| | | | |
|---|---|---|---|
| **Other Health Endpoints** | | | |
| Acute bronchitis | PM2.5 | Dockery et al. (1996)1216 | 8–12 years |
| Upper respiratory symptoms | PM2.5 | Pope et al. (1991)1217 | Asthmatics, 9–11 years |
| Lower respiratory symptoms | PM2.5 | Schwartz and Neas (2000)1218 | 7–14 years |
| Asthma exacerbations | PM2.5 | Pooled estimate:<br>Ostro et al. (2001)1219 (cough, wheeze and shortness of breath)<br>Vedal et al. (1998)1220 (cough) | 6–18 yearsa |
| Work loss days | PM2.5 | Ostro (1987)1221 | 18–65 years |
| School absence days | O3 | Pooled estimate:<br>Gilliland et al. (2001)1222<br>Chen et al. (2000)1223 | 5–17 yearsb |
| Minor Restricted Activity Days (MRADs) | O3 | Ostro and Rothschild (1989)1224 | 18–65 years |
| | PM2.5 | Ostro and Rothschild (1989) | 18–65 years |

Notes:

a The original study populations were 8 to 13 for the Ostro et al. (2001) study and 6 to 13 for the Vedal et al. (1998) study. Based on advice from the Science Advisory Board Health Effects Subcommittee (SAB-HES), we extended the applied population to 6 to 18, reflecting the common biological basis for the effect in children in the broader age group. See: U.S. Science Advisory Board. 2004. Advisory Plans for Health Effects Analysis in the Analytical Plan for EPA’s Second Prospective Analysis –Benefits and Costs of the Clean Air Act, 1990—2020. EPA-SAB-COUNCIL-ADV-04-004. See also National Research Council (NRC). 2002. Estimating the Public Health Benefits of Proposed Air Pollution Regulations. Washington, DC: The National Academies Press.

b Gilliland et al. (2001) studied children aged 9 and 10. Chen et al. (2000) studied children 6 to 11. Based on recent advice from the National Research Council and the EPA SAB-HES, we have calculated reductions in school absences for all school-aged children based on the biological similarity between children aged 5 to 17.

In selecting epidemiological studies as sources of effect estimates, we applied several criteria to develop a set of studies that is likely to provide the best estimates of impacts in the U.S. To account for the potential impacts of different health care systems or underlying health status of populations, we give preference to U.S. studies over non-U.S. studies. In addition, due to the potential for confounding by co-pollutants, we give preference to effect estimates from models including both ozone and PM over effect estimates from single-pollutant models.1225,1226

### Treatment of Potential Thresholds in PM2.5-Related Health Impact Functions

In recent analyses, OTAQ has estimated $PM_{2.5}$-related benefits assuming that a threshold exists in the PM-related concentration-response functions (at 10 µg/m$^3$) below which there are no associations between exposure to $PM_{2.5}$ and health impacts. For the analysis of the final rule, however, we have revised this assumption. As explained in the recently proposed Portland Cement MACT RIA, EPA’s preferred benefits estimation approach assumes a no-threshold model that calculates incremental benefits down to the lowest modeled $PM_{2.5}$ air quality levels.

EPA strives to use the best available science to support our benefits analyses, and we recognize that interpretation of the science regarding air pollution and health is dynamic and evolving. Based on our review of the body of scientific literature, EPA applied the no-threshold model in this analysis. EPA's draft Integrated Science Assessment,[1227,1228] which was recently reviewed by EPA’s Clean Air Scientific Advisory Committee,[1229,1230] concluded that the scientific literature consistently finds that a no-threshold log-linear model most adequately portrays the PM-mortality concentration-response relationship while recognizing potential uncertainty about the exact shape of the concentration-response function.[YYYYYYYYYYYYY] Although this document does not represent final agency policy that has undergone the full agency scientific review process, it provides a basis for reconsidering the application of thresholds in $PM_{2.5}$ concentration-response functions used in EPA's RIAs.[ZZZZZZZZZZZZZ] It is important to note that while CASAC provides advice regarding the science associated with setting the National Ambient Air Quality Standards, typically other scientific advisory bodies provide specific advice regarding benefits analysis.[AAAAAAAAAAAAAA,1231]

As can be seen in Table 5.4-11, we conducted a sensitivity analysis for premature mortality, with alternative thresholds at 3 $\mu g/m^3$ (the "background," or no-threshold, assumption), 7.5 $\mu g/m^3$, 10 $\mu g/m^3$, 12 $\mu g/m^3$, and 14 $\mu g/m^3$**.** By replacing the no-threshold assumption in the ACS premature mortality function with a 10 $\mu g/m^3$ threshold model, the number of avoided incidences of premature mortality would change dramatically.

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[YYYYYYYYYYYYY] It is important to note that uncertainty regarding the shape of the concentration-response function is conceptually distinct from an assumed threshold. An assumed threshold (below which there are no health effects) is a discontinuity, which is a specific example of non-linearity.

[ZZZZZZZZZZZZZ] The final PM ISA, which will have undergone the full agency scientific review process, is scheduled to be completed in late December 2009.

[AAAAAAAAAAAAAA] In the Portland Cement RIA, EPA solicited comment on the use of the no-threshold model for benefits analysis within the preamble of that proposed rule. The comment period for the Portland Cement proposed NESHAP closed on September 4, 2009 (Docket ID No. EPA–HQ–OAR–2002–0051 available at http://www.regulations.gov). EPA is currently reviewing those comments.

**Table 5.4-11. PM-Related Mortality Impacts Associated with the Mandated Renewable Fuel Volumes: Threshold Sensitivity Analysis Using the ACS Study (Pope et al., 2002)[a]**

| Level of Assumed Threshold | PM Mortality Incidence | |
|---|---|---|
| | 2022 RFS2 Control Case Compared to RFS1 Reference Case | 2022 RFS2 Control Case Compared to AEO Reference Case |
| 15 µg/m3 [b] | 9 | -6 |
| 12 µg/m3 | 13 | -14 |
| 10 µg/m3 [c] | -2 | 1 |
| 7.5 µg/m3 [d] | -66 | -11 |
| 3 µg/m3 [e] | -110 | -33 |

Notes:

[a] Note that this table only presents the effects of a threshold on PM-related mortality incidence based on the ACS study. Negative values indicate a disbenefit, or additional mortality incurred.
[b] Alternative annual PM NAAQS.
[c] Previous threshold assumption
[d] SAB-HES (2004)[86]
[e] NAS (2002)[87]

### 5.4.5 Economic Values for Health Outcomes

Reductions in ambient concentrations of air pollution generally lower the risk of future adverse health effects for a large population, while the reverse is also generally true. Therefore, the appropriate economic measure is willingness-to-pay (WTP) for changes in risk of a health effect rather than WTP for a health effect that would occur with certainty (Freeman, 1993). Epidemiological studies generally provide estimates of the relative risks of a particular health effect that is avoided because of a reduction in air pollution. We converted those to units of avoided statistical incidence for ease of presentation. We calculated the value of avoided statistical incidences by dividing individual WTP for a risk reduction by the related observed change in risk. For example, suppose a pollution-reduction regulation is able to reduce the risk of premature mortality from 2 in 10,000 to 1 in 10,000 (a reduction of 1 in 10,000). If individual WTP for this risk reduction is $100, then the WTP for an avoided statistical premature death is $1 million ($100/0.0001 change in risk).

WTP estimates generally are not available for some health effects, such as hospital admissions. In these cases, we used the cost of treating or mitigating the effect as a primary estimate. These cost-of-illness (COI) estimates generally understate the true value of reducing the risk of a health effect, because they reflect the direct expenditures related to treatment, but not the value of avoided pain and suffering (Harrington and Portney, 1987; Berger, 1987). We provide unit values for health endpoints (along with information on the distribution of the unit value) in Table 5.4-12. All values are in constant year 2006 dollars, adjusted for growth in real income out to 2022 using projections provided by Standard and Poor's. Economic theory argues that WTP for most goods (such as environmental protection) will increase if real income increases. Many of the valuation studies used in this analysis were conducted in the late 1980s and early 1990s. Because real income has grown since the studies were conducted, people's willingness to pay for reductions in the risk of premature death and disease likely has grown as well. We did not adjust cost of illness-based values because they are based on current costs. Similarly, we did not adjust the value of school absences, because that value is based on current wage rates. For details on valuation estimates for PM-related endpoints, see the 2006 PM NAAQS RIA. For details on valuation estimates for ozone-related endpoints, see the 2008 Ozone NAAQS RIA.

### Table 5.4-12. Unit Values Used for Economic Valuation of Health Endpoints (2000$)[a]

| Health Endpoint | Central Estimate of Value Per Statistical Incidence | | | Derivation of Estimates |
|---|---|---|---|---|
| | 1990 Income Level | 2020 Income Level[b] | 2030 Income Level[b] | |
| Premature Mortality (Value of a Statistical Life): PM$_{2.5}$- and Ozone-related | $6,320,000 | $7,590,000 | $7,800,000 | EPA currently recommends a default central VSL of $6.3 million based on a Weibull distribution fitted to twenty-six published VSL estimates (5 contingent valuation and 21 labor market studies). The underlying studies, the distribution parameters, and other useful information are available in Appendix B of EPA's current Guidelines for Preparing Economic Analyses. The guidelines can be accessed at: http://yosemite.epa.gov/ee/epa/eermfile.nsf/vwAN/EE-0516-01.pdf/$File/EE-0516-01.pdf |
| Chronic Bronchitis (CB) | $340,000 | $420,000 | $430,000 | Point estimate is the mean of a generated distribution of WTP to avoid a case of pollution-related CB. WTP to avoid a case of pollution-related CB is derived by adjusting WTP (as described in Viscusi et al., [1991][1232]) to avoid a severe case of CB for the difference in severity and taking into account the elasticity of WTP with respect to severity of CB. |
| Nonfatal Myocardial Infarction (heart attack) | | | | Age-specific cost-of-illness values reflect lost earnings and direct medical costs over a 5-year period following a nonfatal MI. Lost earnings estimates are based on Cropper and Krupnick (1990).[1233] Direct medical costs are based on simple average of estimates from Russell et al. (1998)[1234] and Wittels et al. (1990).[1235]<br>Lost earnings:<br>Cropper and Krupnick (1990). Present discounted value of 5 years of lost earnings:<br>age of onset: at 3% at 7%<br>25-44 $8,774 $7,855<br>45-54 $12,932 $11,578<br>55-65 $74,746 $66,920<br>Direct medical expenses: An average of:<br>1. Wittels et al. (1990) ($102,658—no discounting)<br>2. Russell et al. (1998), 5-year period ($22,331 at 3% discount rate; $21,113 at 7% discount rate) |
| 3% discount rate | | | | |
| Age 0–24 | $66,902 | $66,902 | $66,902 | |
| Age 25–44 | $74,676 | $74,676 | $74,676 | |
| Age 45–54 | $78,834 | $78,834 | $78,834 | |
| Age 55–65 | $140,649 | $140,649 | $140,649 | |
| Age 66 and over | $66,902 | $66,902 | $66,902 | |
| 7% discount rate | | | | |
| Age 0–24 | $65,293 | $65,293 | $65,293 | |
| Age 25–44 | $73,149 | $73,149 | $73,149 | |
| Age 45–54 | $76,871 | $76,871 | $76,871 | |
| Age 55–65 | $132,214 | $132,214 | $132,214 | |
| Age 66 and over | $65,293 | $65,293 | $65,293 | |

## Table 5.4-12. Unit Values Used for Economic Valuation of Health Endpoints (2000$)[a] (continued)

| Health Endpoint | Central Estimate of Value Per Statistical Incidence | | | Derivation of Estimates |
|---|---|---|---|---|
| | 1990 Income Level | 2020 Income Level[b] | 2030 Income Level[b] | |
| Hospital Admissions | | | | |
| Chronic Obstructive Pulmonary Disease (COPD)<br>(ICD codes 490-492, 494-496) | $12,378 | $12,378 | $12,378 | The COI estimates (lost earnings plus direct medical costs) are based on ICD-9 code-level information (e.g., average hospital care costs, average length of hospital stay, and weighted share of total COPD category illnesses) reported in Agency for Healthcare Research and Quality (2000)[1236] (www.ahrq.gov). |
| Pneumonia<br>(ICD codes 480-487) | $14,693 | $14,693 | $14,693 | The COI estimates (lost earnings plus direct medical costs) are based on ICD-9 code-level information (e.g., average hospital care costs, average length of hospital stay, and weighted share of total pneumonia category illnesses) reported in Agency for Healthcare Research and Quality (2000) (www.ahrq.gov). |
| Asthma Admissions | $6,634 | $6,634 | $6,634 | The COI estimates (lost earnings plus direct medical costs) are based on ICD-9 code-level information (e.g., average hospital care costs, average length of hospital stay, and weighted share of total asthma category illnesses) reported in Agency for Healthcare Research and Quality (2000) (www.ahrq.gov). |
| All Cardiovascular<br>(ICD codes 390-429) | $18,387 | $18,387 | $18,387 | The COI estimates (lost earnings plus direct medical costs) are based on ICD-9 code-level information (e.g., average hospital care costs, average length of hospital stay, and weighted share of total cardiovascular category illnesses) reported in Agency for Healthcare Research and Quality (2000) (www.ahrq.gov). |
| Emergency Room Visits for Asthma | $286 | $286 | $286 | Simple average of two unit COI values:<br>(1) $311.55, from Smith et al. (1997)[1237] and<br>(2) $260.67, from Stanford et al. (1999).[1238] |

## Table 5.4-12. Unit Values Used for Economic Valuation of Health Endpoints (2000$)[a] (continued)

| Health Endpoint | Central Estimate of Value Per Statistical Incidence | | | Derivation of Estimates |
|---|---|---|---|---|
| | 1990 Income Level | 2020 Income Level[b] | 2030 Income Level[b] | |
| Respiratory Ailments Not Requiring Hospitalization | | | | |
| Upper Respiratory Symptoms (URS) | $25 | $27 | $27 | Combinations of the three symptoms for which WTP estimates are available that closely match those listed by Pope et al. result in seven different "symptom clusters," each describing a "type" of URS. A dollar value was derived for each type of URS, using mid-range estimates of WTP (IEc, 1994)[1239] to avoid each symptom in the cluster and assuming additivity of WTPs. The dollar value for URS is the average of the dollar values for the seven different types of URS. |
| Lower Respiratory Symptoms (LRS) | $16 | $17 | $17 | Combinations of the four symptoms for which WTP estimates are available that closely match those listed by Schwartz et al. result in 11 different "symptom clusters," each describing a "type" of LRS. A dollar value was derived for each type of LRS, using mid-range estimates of WTP (IEc, 1994) to avoid each symptom in the cluster and assuming additivity of WTPs. The dollar value for LRS is the average of the dollar values for the 11 different types of LRS. |
| Asthma Exacerbations | $42 | $45 | $45 | Asthma exacerbations are valued at $42 per incidence, based on the mean of average WTP estimates for the four severity definitions of a "bad asthma day," described in Rowe and Chestnut (1986).[1240] This study surveyed asthmatics to estimate WTP for avoidance of a "bad asthma day," as defined by the subjects. For purposes of valuation, an asthma attack is assumed to be equivalent to a day in which asthma is moderate or worse as reported in the Rowe and Chestnut (1986) study. |
| Acute Bronchitis | $360 | $380 | $390 | Assumes a 6-day episode, with daily value equal to the average of low and high values for related respiratory symptoms recommended in Neumann et al. (1994).[1241] |

### Table 5.4-12. Unit Values Used for Economic Valuation of Health Endpoints (2000$)[a] (continued)

| Health Endpoint | Central Estimate of Value Per Statistical Incidence | | | Derivation of Estimates |
|---|---|---|---|---|
| | 1990 Income Level | 2020 Income Level[b] | 2030 Income Level[b] | |
| Restricted Activity and Work/School Loss Days | | | | |
| Work Loss Days (WLDs) | Variable (national median = ) | | | County-specific median annual wages divided by 50 (assuming 2 weeks of vacation) and then by 5—to get median daily wage. U.S. Year 2000 Census, compiled by Geolytics, Inc. |
| School Absence Days | $75 | $75 | $75 | Based on expected lost wages from parent staying home with child. Estimated daily lost wage (if a mother must stay at home with a sick child) is based on the median weekly wage among women age 25 and older in 2000 (U.S. Census Bureau, Statistical Abstract of the United States: 2001, Section 12: Labor Force, Employment, and Earnings, Table No. 621). This median wage is $551. Dividing by 5 gives an estimated median daily wage of $103.<br>The expected loss in wages due to a day of school absence in which the mother would have to stay home with her child is estimated as the probability that the mother is in the workforce times the daily wage she would lose if she missed a day = 72.85% of $103, or $75. |
| Worker Productivity | $0.95 per worker per 10% change in ozone per day | $0.95 per worker per 10% change in ozone per day | $0.95 per worker per 10% change in ozone per day | Based on $68 – median daily earnings of workers in farming, forestry and fishing – from Table 621, Statistical Abstract of the United States ("Full-Time Wage and Salary Workers – Number and Earnings: 1985 to 2000") (Source of data in table: U.S. Bureau of Labor Statistics, Bulletin 2307 and Employment and Earnings, monthly). |
| Minor Restricted Activity Days (MRADs) | $51 | $54 | $55 | Median WTP estimate to avoid one MRAD from Tolley et al. (1986).[1242] |

[a] All monetized annual benefit estimates associated with the coordinated strategy are presented in year 2000 dollars. We use the Consumer Price Indexes to adjust both WTP- and COI-based benefits estimates to 2007 dollars from 2000 dollars.[1243] For WTP-based estimates, we use an inflation factor of 1.20 based on the CPI-U for "all items." For COI-based estimates, we use an inflation factor of 1.35 based on the CPI-U for medical care.

[b] Our analysis accounts for expected growth in real income over time. Economic theory argues that WTP for most goods (such as environmental protection) will increase if real incomes increase. Benefits are therefore adjusted by multiplying the unadjusted benefits by the appropriate adjustment factor to account for income growth over time. For a complete discussion of how these adjustment factors were derived, we refer the reader to the PM NAAQS regulatory impact analysis. Note that similar adjustments do not exist for cost-of-illness-based unit values. For these, we apply the same unit value regardless of the future year of analysis.

### 5.4.6 Manipulating Air Quality Modeling Data for Health Impacts Analysis

In Chapter 3.4, we summarized the methods for and results of estimating air quality impacts for the mandated renewable fuel volumes. These air quality results are in turn associated with human populations to estimate changes in health effects. For the purposes of this analysis, we focus on the health effects that have been linked to ambient changes in ozone and $PM_{2.5}$ related to emissions associated with the RFS2 mandated fuel volumes. We estimate ambient $PM_{2.5}$ and ozone concentrations using the Community Multiscale Air Quality model (CMAQ). This section describes how we converted the CMAQ modeling output into full-season profiles suitable for the health impacts analysis.

#### General Methodology

First, we extracted hourly, surface-layer PM and ozone concentrations for each grid cell from the standard CMAQ output files. For ozone, these model predictions are used in conjunction with the observed concentrations obtained from the Aerometric Information Retrieval System (AIRS) to generate ozone concentrations for the entire ozone season.[BBBBBBBBBBBBBB,CCCCCCCCCCCCCC] The predicted changes in ozone concentrations from the future-year base case to future-year control scenario serve as inputs to the health and welfare impact functions of the benefits analysis (i.e., BenMAP).

To estimate ozone-related health effects for the contiguous United States, full-season ozone data are required for every BenMAP grid-cell. Given available ozone monitoring data, we generated full-season ozone profiles for each location in two steps: (1) we combined monitored observations and modeled ozone predictions to interpolate hourly ozone concentrations to a grid of 12-km by 12-km population grid cells for the contiguous 48 states, and (2) we converted these full-season hourly ozone profiles to an ozone measure of interest, such as the daily maximum 8-hour average.[DDDDDDDDDDDDDD,EEEEEEEEEEEEEE]

For $PM_{2.5}$, we also use the model predictions in conjunction with observed monitor data. CMAQ generates predictions of hourly PM species concentrations for every grid. The species include a primary coarse fraction (corresponding to PM in the 2.5 to 10 micron size range), a primary fine fraction (corresponding to PM less than 2.5 microns in diameter), and several secondary particles (e.g., sulfates, nitrates, and organics). $PM_{2.5}$ is calculated as the sum of the primary fine fraction and all of the secondarily formed particles. Future-year estimates of $PM_{2.5}$ were calculated using relative reduction factors (RRFs) applied to 2005 ambient $PM_{2.5}$ and $PM_{2.5}$ species concentrations. A gridded field of $PM_{2.5}$ concentrations was created by interpolating Federal Reference Monitor ambient data and IMPROVE ambient data. Gridded fields of $PM_{2.5}$

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[BBBBBBBBBBBBBB] The ozone season for this analysis is defined as the 5-month period from May to September.

[CCCCCCCCCCCCCC] Based on AIRS, there were 961 ozone monitors with sufficient data (i.e., 50 percent or more days reporting at least nine hourly observations per day [8 am to 8 pm] during the ozone season).

[DDDDDDDDDDDDDD] The 12-km grid squares contain the population data used in the health benefits analysis model, BenMAP.

[EEEEEEEEEEEEEE] This approach is a generalization of planar interpolation that is technically referred to as enhanced Voronoi Neighbor Averaging (EVNA) spatial interpolation. See the BenMAP manual for technical details, available for download at http://www.epa.gov/air/benmap.

species concentrations were created by interpolating US EPA speciation network (ESPN) ambient data and IMPROVE data. The ambient data were interpolated to the CMAQ 12 km grid.

The procedures for determining the RRFs are similar to those in US EPA's draft guidance for modeling the $PM_{2.5}$ standard (EPA, 1999). The guidance recommends that model predictions be used in a relative sense to estimate changes expected to occur in each major $PM_{2.5}$ species. The procedure for calculating future-year $PM_{2.5}$ design values is called the "Speciated Modeled Attainment Test (SMAT)." EPA used this procedure to estimate the ambient impacts of the coordinated strategy to control ship emissions.

Table 5.4-13 provides those ozone and $PM_{2.5}$ metrics for grid cells in the modeled domain that enter the health impact functions for health benefits endpoints. The population-weighted average reflects the baseline levels and predicted changes for more populated areas of the nation. This measure better reflects the potential benefits through exposure changes to these populations.

**Table 5.4-13.**
**Summary of CMAQ-Derived Population-Weighted Ozone and $PM_{2.5}$ Air Quality Metrics for Health Impact Endpoints Associated with the Mandated Renewable Fuel Volumes**

| | 2022 RFS2 control case compared to the RFS1 reference case | | 2022 RFS2 control case compared to the AEO reference case | |
|---|---|---|---|---|
| Statistic[a] | Reference | Change[b] | Reference | Change[b] |
| Ozone Metric: National Population-Weighted Average (ppb)[c] | | | | |
| Daily Maximum 8-Hour Average Concentration | 44.513 | -0.177 | 44.575 | -0.116 |
| $PM_{2.5}$ Metric: National Population-Weighted Average ($ug/m^3$) | | | | |
| Annual Average Concentration | 9.658 | -0.006 | 9.662 | -0.002 |

Notes:

[a] Ozone and $PM_{2.5}$ metrics are calculated at the CMAQ grid-cell level for use in health effects estimates. Ozone metrics are calculated over relevant time periods during the daylight hours of the "ozone season" (i.e., May through September).

[b] The change is defined as the reference case value minus the final rule value. A negative change means that the population-weighted average has increased from the reference scenario to the final rule scenario.

[c] Calculated by summing the product of the projected CMAQ grid-cell population and the estimated CMAQ grid cell seasonal ozone concentration and then dividing by the total population.

### 5.4.7 Methods for Describing Uncertainty

The National Research Council (NRC)[1244] highlighted the need for EPA to conduct rigorous quantitative analysis of uncertainty in its benefits estimates and to present these estimates to decision makers in ways that foster an appropriate appreciation of their inherent uncertainty. In response to these comments, EPA's Office of Air and Radiation (OAR) is developing a comprehensive strategy for characterizing the aggregate impact of uncertainty in key modeling elements on both health incidence and benefits estimates. Components of that process include emissions modeling, air quality modeling, health effects incidence estimation, and valuation.

In benefit analyses of air pollution regulations conducted to date, the estimated impact of reductions in premature mortality has accounted for 85% to 95% of total benefits. Therefore, it is particularly important to characterize the uncertainties associated with reductions in premature mortality. The health impact functions used to estimate avoided premature deaths associated with reductions in ozone have associated standard errors that represent the statistical errors around the effect estimates in the underlying epidemiological studies.[FFFFFFFFFFFFF] In our results, we report credible intervals based on these standard errors, reflecting the uncertainty in the estimated change in incidence of avoided premature deaths. We also provide multiple estimates, to reflect model uncertainty between alternative study designs.

For premature mortality associated with exposure to PM, we follow the same approach that has been used in several recent RIAs.[1245,1246,1247] First, we use Monte Carlo methods for estimating random sampling error associated with the concentration response functions from epidemiological studies and economic valuation functions. Monte Carlo simulation uses random sampling from distributions of parameters to characterize the effects of uncertainty on output variables, such as incidence of premature mortality. Specifically, we used Monte Carlo methods to generate confidence intervals around the estimated health impact and dollar benefits. Distributions for individual effect estimates are based on the reported standard errors in the epidemiological studies. Distributions for unit values are described in Table 6-11.

Second, as a sensitivity analysis, we use the results of our expert elicitation of the concentration response function describing the relationship between premature mortality and ambient $PM_{2.5}$ concentration.[GGGGGGGGGGGGG, 1248] Incorporating only the uncertainty from random sampling error omits important sources of uncertainty (e.g., in the functional form of the model; whether or not a threshold may exist). This second approach attempts to incorporate these other sources of uncertainty.

Use of the expert elicitation and incorporation of the standard errors approaches provide insights into the likelihood of different outcomes and about the state of knowledge regarding the benefits estimates. Both approaches have different strengths and weaknesses, which are fully described in Chapter 5 of the PM NAAQS RIA.[1249]

These multiple characterizations, including confidence intervals, omit the contribution to overall uncertainty of uncertainty in air quality changes, baseline incidence rates, populations exposed and transferability of the effect estimate to diverse locations. Furthermore, the approach presented here does not yet include methods for addressing correlation between input parameters and the identification of reasonable upper and lower bounds for input distributions characterizing uncertainty in additional model elements. As a result, the reported confidence intervals and range of estimates give an incomplete picture about the overall uncertainty in the estimates. This information should be interpreted within the context of the larger uncertainty surrounding the entire analysis.

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[FFFFFFFFFFFFF] Health impact functions measure the change in a health endpoint of interest, such as hospital admissions, for a given change in ambient ozone or PM concentration.

[GGGGGGGGGGGGG] Expert elicitation is a formal, highly structured and well documented process whereby expert judgments, usually of multiple experts, are obtained (Ayyb, 2002).

## 5.5 Impacts of Increasing Volume Requirements in the RFS2 Program

The displacement of gasoline and diesel with renewable fuels has a wide range of environmental and economic impacts. As we describe in Chapters 2-6 of the RIA, we have assessed many of these impacts for the final rule. It is difficult to ascertain how much of these impacts might be due to the natural growth in renewable fuel use due to market forces as crude oil prices rise versus what might be forced by the RFS2 standards. Regardless, these assessments provide important information on the wider public policy considerations related to renewable fuel production and use, climate change, and national energy security. Where possible, we have tried to provide two perspectives on the impacts of the renewable fuel volumes mandated in EISA – both relative to the RFS1 mandated volumes, and relative to a projection from EIA (AEO 2007) of renewable fuel volumes that would have been expected without EISA.

Based on the results of our analyses, when fully phased in by 2022, the increased volume of renewable fuel required by this final rule in comparison to the AEO 2007 forecast would result in 138 million metric tons fewer CO2-equivalent GHG emissions (annual average over 30 years), the equivalent of removing 27 million vehicles from the road today. Below we report GHG benefits in the year 2022. The benefit stream from GHG reductions through time after 2022 would show increasing GHG benefits.

At the same time, increases in emissions of hydrocarbons, nitrogen oxides, particulate matter, and other pollutants are projected to lead to increases in population-weighted annual average ambient PM and ozone concentrations, which in turn are anticipated to lead to up to 245 cases of adult premature mortality. The air quality impacts, however, are highly variable from region to region. Ambient $PM_{2.5}$ is likely to increase in areas associated with biofuel production and transport and decrease in other areas; for ozone, many areas of the country will experience increases and a few areas will see decreases. Ethanol concentrations will increase substantially; for the other modeled air toxics there are some localized impacts, but relatively little impact on national average concentrations. It is important to note that these air quality results represent the impact of an incremental increase in ethanol and other renewable fuels and do not estimate the total air quality impact of the RFS2 volumes of renewable fuels as compared to near-zero levels. EPA will conduct that type of analysis as part of the “anti-backsliding” study required by Clean Air Act section 211(v), separate from this final action. The “anti-backsliding” study will use improved emissions data and consider different ethanol blend levels. Clean Air Act section 211(v) requires EPA to issue regulations that mitigate, to the greatest extent achievable, adverse impacts on air quality, considering the results of the “anti-backsliding” study.

In addition to air quality, there are also expected to be adverse impacts on both water quality and quantity as the production of biofuels and their feedstocks increase.

Also, the increased volumes of renewable fuels required by this final rule are projected to have a number of other energy and economic impacts. The increased renewable fuel use is estimated to reduce dependence on foreign sources of crude oil, increase domestic sources of energy, and diversify our energy portfolio to help in moving beyond a petroleum-based economy. The increased use of renewable fuels is also expected to have the added benefit of providing an expanded market for agricultural products such as corn and soybeans and open new markets for the development of cellulosic feedstock industries and conversion technologies.

Overall, we estimate that the renewable fuel standards will result in significant net benefits, ranging between $13 and $26 billion in 2022. Table 5.5-1 summarizes the results of our impacts analyses of the RFS2 standards relative to the AEO2007 reference case and identifies the section where you can find further explanation of it. As we work to implement the requirements of EISA, we will continue to assess these impacts.

### Table 5.5-1
### Impact Summary of the RFS2 Standards in 2022 Relative to the AEO2007 Reference Case (2007 Dollars)

| **Category** | **Impact in 2022** | **Chapter Discussed** |
|---|---|---|
| **Emissions and Air Quality** | | |
| GHG Emissions | -138 million metric tons | 2.7 |
| Non-GHG Emissions (criteria and toxic pollutants) | -1% to +10% depending on the pollutant | 3.2 |
| Nationwide Ozone | +0.12 ppb population-weighted seasonal max 8hr average | 5.4 |
| Nationwide $PM_{2.5}$ | +0.002 $\mu g/m^3$ population-weighted annual average $PM_{2.5}$ | 5.4 |
| Nationwide Ethanol | +0.409 $\mu g/m^3$ population-weighted annual average | 3.4 |
| Other Nationwide Air Toxics | -0.0001 to -0.023 $\mu g/m^3$ population-weighted annual average depending on the pollutant | 3.4 |
| $PM_{2.5}$-related Premature Mortality | 33 to 85 additional cases of adult mortality (estimates vary by study) | 5.4 |
| Ozone-related Premature Mortality | 36 to 160 additional cases of adult mortality (estimates vary by study) | 5.4 |
| | | |
| **Other Environmental Impacts** | | |
| Loadings to the Mississippi River from the Upper Mississippi River Basin | Nitrogen: +1.43 billion lbs. (1.2%)<br>Phosphorus: +132 million lbs. (0.7%) | 6.4 |
| | | |
| **Fuel Costs** | | |
| Gasoline Costs | -2.4¢/gal | 4.4 |
| Diesel Costs | -12.1 ¢/gal | 4.4 |
| Overall Fuel Cost | -$11.8 Billion | 4.4 |
| Gasoline and Diesel Consumption | - 13.6 Bgal | 4.4 |
| Total Capital Costs Thru 2022 | $90.5 Billion | 4.4 |
| | | |
| **Food Costs** | | |
| Corn | +8.2% | 5.1 |
| Soybeans | +10.3% | 5.1 |
| Food | +$10 per capita | 5.1 |
| | | |
| **Economic Impacts** | | |

| | | |
|---|---|---|
| Energy Security | +$2.6 Billion | 5.2 |
| Monetized Health Impacts | -$0.63 to -$2.2 Billion | 5.4 |
| GHG Impacts (SCC)[a] | +$0.6 to $12.2 Billion (estimates vary by SCC assumption) | 5.3 |
| Oil Imports | -$41.5 Billion | 5.2 |
| Farm Gate Food | +$3.6 Billion | 5.1 |
| Farm Income | +$13 Billion (+36%) | 5.1 |
| Corn Exports | -$57 Million (-8%) | 5.1 |
| Soybean Exports | -$453 Million (-14%) | 5.1 |
| | | |
| **Total Net Benefits**[b] | +$13 to $26 Billion (estimates vary by SCC assumption) | 5.5 |
| | | |

[a] The models used to estimate SCC values have not been exercised in a systematic manner that would allow researchers to assess the probability of different values. Therefore, the interim SCC values should not be considered to form a range or distribution of possible or likely values. See Chapter 5.3 for a complete summary of the interim SCC values.

[b] Sum of Overall Fuel Costs, Energy Security, Monetized Health Impacts, and GHG Impacts (SCC).

# Chapter 6: Impacts on Water

## 6.1 Feedstock Production and Water Quality

As the production and price of corn and other biofuel feedstocks increase, there may be substantial impacts to both water quality and water quantity. To analyze these impacts, EPA focused on corn production for several reasons. Corn acres have increased dramatically, 20% in 2007 from 2006, an increase of over 15 million additional corn acres for a total of 93.6 million acres. Over two-thirds of the new corn acres came from soybean production. Most of the remaining acres came from the conversion to corn from cotton. Although corn acres declined to 87 million acres in 2009 due to strong prices for other commodities including soybeans, total corn acres remained the second highest since 1946.[1250]

There are three major pathways for contaminants to reach water from agricultural lands: runoff from the land's surface, subsurface tile drains, or leaching to ground water. A variety of management factors influence the potential for contaminants such as fertilizers, sediment, and pesticides to reach water from agricultural lands. These factors include nutrient and pesticide application rates and application methods, use of conservation practices and crop rotations by farmers, and acreage and intensity of tile drained lands. Additional factors outside an agricultural producers control include soil characteristics, climate, and proximity to waterbodies.

### 6.1.1 Corn Production and Water Quality

The rapid growth in corn acres may have major implications for water quality. Unlike soybeans and other legumes, corn needs large amounts of fertilizer, especially nitrogen fertilizer, to produce economic yields. Of all current and potential feedstocks for biofuels, corn has the greatest application rates of both fertilizer and pesticides per acre and accounts for the largest share of nitrogen use among all crops.[1251] If fertilizers are applied at rates or times when the corn cannot use them, they are available to runoff or leach to water. Corn generally utilizes only 40 to 60% of applied nitrogen. The remaining nitrogen is available to leave the field and runoff to surface waters, leach into ground water, or volatilize to the air where it can return to water through depositional processes. Farmers were expected to apply an additional one million tons of nitrogen fertilizer to the 2007 corn crop.[1252]

Historically, corn has been grown in rotation with other crops such as wheat, hay, oats, and especially soybeans. As corn prices increase relative to prices for other crops, farmers chose to grow corn every year (continuous corn). Much of the recent growth in corn acres has come from reductions in a corn-soybean rotation to continuous corn. Although the amount of losses of nitrogen fertilizers to ground and surface water vary, continuous corn loses significantly more nitrogen annually than a corn-soybean rotation.[1253] In 2005, the latest year for which data was analyzed, the U.S. average nitrogen fertilization rate for corn was 138 pounds per acre. For soybeans the average rate was 16 pounds per acre.[1254] Soybeans fix nitrogen, so they do not require as much fertilizer for adequate growth.

Continuous corn may have additional impacts on the rates of fertilizer and pesticide use. Continuous corn has lower yields per acre than corn grown in rotation. In response, farmers may add higher rates of nitrogen fertilizer to try to match yields of corn grown in rotation. Alternatively, if farmers maintain fertilization rates with these reduced yields, the amount of unused nutrients will increase and eventually be lost to the environment. Growing continuous corn also increases population densities of pests such as corn rootworm. Farmers may increase use of pesticides to control these pests. Total corn herbicide use may also increase due to the additional corn acres, especially for atrazine, the most commonly used herbicide on corn.

There are potential toxicity concerns with volatilization of pesticide active ingredients[1255] in addition to concerns with contamination of foods and drinking water. Furthermore, raising acreage under corn production will increase the quantity of pesticide products in use. Further assessment is necessary to determine whether there is the potential for adverse human health effects from any increase in pesticide use associated with increased domestic corn production.

The most commonly used types of pesticides associated with corn production and storage largely belong to two broad use categories, herbicides and insecticides. The majority of the more common corn herbicide products presently on the market contain an organochlorine-type (OC) active ingredient (AI). For the most part, OC herbicides inhibit cell division and growth while a subgroup of these products, the atrazine-containing OC herbicides, inhibit plant photosynthesis. Another type of common corn herbicide, the phosphonoglycene or glyphosate–containing organophosphate (OP) herbicides, inhibit protein synthesis in plants. Several of the common corn herbicide compounds, such as acetochlor, carbaryl and alachlor, are classified by EPA as known or likely human carcinogens and oral exposure to some of these AI compounds at high enough levels has resulted in adverse health effects, on organs such as the liver or kidney in animals.[1256,] [1257,] [1258]

The majority of common corn insecticides are split fairly evenly between OP- and carbamate-type AI compounds, with the top selling corn insecticide products, by sales of AI by weight, generally contain methomyl. Methomyl is an N-methyl-carbamide compound which inhibits the acetylcholinesterase enzyme, causing neurotoxicity in both insects and humans.[1259] Methomyl is classified by EPA as an E/unlikely human carcinogen[1260] and its use is regulated as a compound highly toxic to most aquatic and land animals.

High corn prices may encourage farmers to grow corn on land where row crops are not currently grown. If land is not in row crop production, it generally is an indication that the land is marginal for row crop production though the land may still be used for agriculture, such as pasture land. Typically, agricultural producers apply far less fertilizer and pesticide on pasture land than land in row crops. Corn yield on these marginal lands will be lower, limiting nutrient uptake and causing a higher percentage of nutrients under standard fertilization rates to be underutilized and ultimately lost to the environment. However since nitrogen fertilizer prices are tied to natural gas prices, fertilizer costs have increased significantly. According to U. S. Department of Agriculture (USDA) Economic Research Service (ERS), fertilizer prices have been rising steadily since 2002. Through 2008, the annual average prices paid for fertilizers rose 264%. The annual average prices paid for fertilizers were up 82% in 2008 alone. In 2009, ERS predicts that the annual average prices paid for fertilizers will fall 26.5%. In October 2009 fertilizer prices returned to the December 2007 level, when the run-up in prices started.[1261] It is unclear how agricultural producers responded to these changes in both corn and fertilizer prices.

EPA has no data indicating US farmers will increase their corn fertilization rates in response to higher corn prices. However, as demand for corn expands, additional acres panted to corn will likely results in increased amounts of fertilizer applied. The USDA National Agricultural Statistics Service has announced that it will discontinue its national Agriculture Chemical Use reports, collected since 1990, the only survey of its kind. Therefore, it will be very difficult to obtain future information on fertilizer and pesticide application rates.

Artificial drainage is another important factor in determining the losses of nutrients from cropland. Artificial drainage consists either of subsurface tiles/pipes or man-made ditches that move water from wet soils to surface waters so crops can be planted. In a few areas, drains move water to wells and then groundwater instead of to surface water. Artificial drainage has transformed large expanses of historic wetland soils into productive agriculture lands. However, the artificial drains or ditches also move nutrients and pesticides more quickly to surface waters without any of the attenuation that would occur if these contaminants moved through soils or wetlands. The highest proportion of tile drainage occurs in the Upper Mississippi and the Ohio-Tennessee River basins in areas of intensive corn production.[1262] Manmade ditches predominate in areas like the Eastern Shore of the Chesapeake Bay.

### 6.1.2 Impact on Farm Bill Conservation Programs

The increase in corn production and prices may also have significant impacts on conservation programs funded by the USDA. USDA funds a variety of voluntary programs to help agricultural producers implement conservation practices on their operations. These programs fall into two basic categories: land retirement and working lands.

USDA's largest land retirement program and its largest conservation program is the Conservation Reserve Program (CRP). Under CRP farmers receive annual rental payments under 10- to 15- year contracts to take land out of agricultural production and plant grasses or trees on those acres. Generally farmers put land into CRP because it is not as productive and has other characteristics that make the cropland more environmentally sensitive, such as high erosion rates. The 2008 Farm Bill (Food, Conservation and Energy Act of 2008) lowered the cap on CRP acres from 39.2 million acres to 32 million acres. Prior to the passage of the new farm bill, farmers had already not renewed their contracts on over two million acres of CRP in response to higher crop prices. USDA expects another 4.6 million acres to come out of CRP between 2007 and 2010, 1.4 million acres in major corn producing states.[1263]

CRP acres provide valuable environmental benefits both for water quality and for wildlife habitat. CRP is an important component of rare grassland habitats in the Midwest and Great Plains.[1264] CRP payments are based on the average agricultural land rental rates in the area. As land values increase due to increase in crop prices, CRP payments are not keeping up with the higher land rental rates. Farmland in Iowa increased an average of 18% in 2007 from 2006 prices.[1265] Midwestern states, where much of the nation's corn is grown, tend to have reenrollment rates lower than the national average. We note that based on input from USDA, EPA has modeled assuming the 32 million acres of eligible CRP land will remain protected.

The largest USDA conservation program on working lands is the Environmental Quality Incentives Program (EQIP). About $1 billion is given to farmers annually to implement conservation practices on their farms. Farmers are paid a percentage of the cost of installing the practices, generally ranging from 50 to 90%. Conservation practices encompass a wide range that can have a significant impact on pollutants reaching ground or surface water from crop production. EQIP cost-shares with farmers for important practices such as nutrient management, cover crops, livestock manure storage, and riparian buffers. Like CRP, high corn prices may have an impact on the willingness of agricultural producers to participate in EQIP. Producers may require higher payments to offset potential loss of profits through implementation of conservation practices.

The effectiveness of agricultural conservation practices in controlling runoff and/or leaching of nutrients, sediment, and pesticides at the field level has been established by numerous scientific studies across many geographic areas. However, the usefulness of these practices in achieving water quality goals is dependent on their placement within watersheds. To most effectively protect water quality, conservation practices should be targeted to the most vulnerable areas of watersheds. Conservation practices designed to meet wildlife goals will need different targeting mechanisms to ensure adequate habitat. USDA through the Conservation Effects Assessment Project (CEAP) is trying to evaluate the effectiveness of controlling pollution from agricultural lands at the watershed level.[HHHHHHHHHHHHHH] In order to ensure that Farm Bill conservation programs meet their environmental quality goals, the EPA's Science Advisory Board report to the Gulf of Mexico Task Force (SAB) also recommends implementing the practices through competitive bidding to ensure that the highest environmental benefit is achieved at the least cost.[1266] It also warns that voluntary programs without economic incentives are unlikely to be effective to control nitrogen and phosphorus, except for a few practices.

The most cost-effective practices on working lands include: riparian buffers; crop rotation; appropriate rate, timing, and method of nutrient application; cover crops; and, on tile-drained lands, treatment wetlands and controlled drainage. These practices have significant water pollution reduction benefits that vary based on the site-specific conditions and on the implementation and operation and maintenance of the practice. For example, controlled drainage can reduce nitrogen loads by 30%; treatment wetlands by 40% to 90%; vegetative buffers by 12% to 90%.

### 6.1.3 Other Agricultural Biofuel Feedstocks

While corn is the most common feedstock for biofuel production by far, under this proposal, in later years other agricultural feedstocks will become increasingly important. These feedstocks will have dramatically different impacts on water quality. Biodiesel feedstocks, primarily soybeans, as well as cellulosic feedstock such as switchgrass or popular trees are not expected to have significant water quality impacts. As noted previously, soybeans require little to no additional nitrogen fertilizer. However, soybeans have less residue remaining after harvest

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[HHHHHHHHHHHHHH] See http://www.nrcs.usda.gov/technical/nri/ceap/index.html compared to corn, so sediment runoff could be more of a concern, depending on how each crop is managed. Switchgrass may be a more favorable biofuels crop for reducing water impacts. It is a native plant which does not require high inputs of fertilizers or pesticides and since it is a perennial crop, there is limited sediment runoff compared to annual crops. There is very minimal acreage of switchgrass grown commercially at the present time, so it is difficult to predict what inputs farmers will use to cultivate it. Some concern has been expressed about the potential in the future for farmers to increase switchgrass fertilizer application rates and irrigation rates to dramatically increase yields.

Corn stover, at the present time, appears to be one of the more viable feedstocks for cellulosic ethanol, especially in the Corn Belt states. Corn stover is the above ground stalks, husks, and corn cobs that remain once the corn grain is harvested. Farmers keep the corn stover on their cropland to maintain the productivity of the soil. Corn stover maintains the soil organic carbon which has many benefits as a source of nutrients, preventing erosion by wind and water, and increasing soil aeration and water infiltration. Wilhelm, et al.[1267] evaluated the amount of corn stover that could be harvested for biofuel production and still maintain soil carbon. In all the soils they evaluated more stover was needed to maintain the soil carbon than for controlling erosion. For a more general discussion of cellulosic ethanol production, see Chapter 5, Section V.B.2. More research is needed to identify the amount of stover that can be removed and retain these important productivity and environmental benefits.

Different conservation systems and conservation practice standards will need to be developed and adopted for cellulosic feedstocks, such as corn stover, switchgrass, and trees for biofuels production. USDA will need to continue to adjust current standards and develop additional standards, where needed, to permit cellulosic feedstocks to be produced and utilized in a sustainable manner.

## 6.2 Ecological Impacts

### 6.2.1 Nutrients

Nitrogen and phosphorus enrichment due to human activities is one of the leading problems facing our nation’s lakes, reservoirs, and estuaries. Nutrient enrichment is also a contributing factor to stream degradation. It has negative impacts on aquatic life in streams; adverse health effects on humans and domestic animals; aesthetic and recreational use impairment; and excessive nutrient input into downstream waterbodies, such as lakes. Excess nutrients in streams can lead to excessive growth of phytoplankton (free-floating algae) in slow-moving rivers, periphyton (algae attached to a surface) in shallow streams, and macrophytes (aquatic plants large enough to be visible to the naked eye) in all waters. Unsightly filamentous algae can impair the aesthetic enjoyment of streams. In more extreme situations, excessive growth of aquatic plants can slow water flow in flat streams and canals, interfere with swimming, and clog the screens on water intakes of water treatment plants and industries.

Nutrient enrichment in streams has also been demonstrated to affect animal communities in these waterbodies. For example, declines in invertebrate community structure have been correlated directly with increases in phosphorus concentration. High concentrations of nitrogen in the form of ammonia are known to be toxic to aquatic animals. Excessive levels of algae have also been shown to be damaging to invertebrates. Finally, fish and invertebrates will experience growth problems and can even die if either oxygen is depleted or pH increases are severe; both of these conditions are symptomatic of eutrophication. As a biologic system becomes more enriched by nutrients, different species of algae may spread and species composition can shift; however, unless such species shifts cause clearly demonstrable symptoms of poor water quality—such as fish kills, toxic algae, or very long streamers of filamentous algae—the general public is unlikely to be aware of this potential ecological concern.

Nutrient pollution is widespread. The most widely known examples of significant nutrient impacts include the Gulf of Mexico and the Chesapeake Bay. For these two areas alone, there are 35 states that contribute the nutrient loadings. There are also known impacts in over 80 estuaries/bays, and thousands of rivers, streams, and lakes. The significance of these impacts has led EPA, States, and the public to come together to place an unprecedented priority on public partnerships, collaboration, better science, and improved tools to reduce nutrient pollution.

Virtually every state and territory is impacted by nutrient-related degradation of our waterways. All but one state and two territories have waterbodies that are polluted by nutrients. States have listed over 10,000 waterbodies that have nutrient and nutrient-related impairments. Fifteen states have more than 200 nutrient-impaired waterbodies each. Reducing nutrient pollution is a priority for EPA.

EPA’s Wadeable Streams Assessment provided the first statistically defensible summary of the condition of the nation’s streams and small rivers.[1268] To perform the assessment, EPA, states, and tribes collected chemical, physical, and biological data at 1,392 perennial stream locations to determine the biological condition of these waters and the primary stressors affecting their quality. Research teams collected samples at sites chosen using a statistical design to ensure representative results. The results of the analysis provide a clear assessment of the biological quality of wadeable, perennial streams and rivers across the country.

The Wadeable Streams Assessment found that excess total nitrogen is the most pervasive biological stressor for the nation. Approximately 32% of the nation’s stream length shows high concentrations of nitrogen compared to reference conditions. Phosphorus exhibits comparable patterns to nitrogen and is the second most-pervasive stressor for the nation’s stream length. Streams with relatively high concentrations of nutrients or excess streambed sediments are two to four times more likely to exhibit poor biological conditions.

The *National Water Quality Inventory: Report to Congress*, prepared under section 305(b) of the Clean Water Act, summarizes water quality reports submitted by the states and territories to EPA. Historically, the National Water Quality Inventories have repeatedly shown that nutrients are a major cause of ambient water quality use impairments. In the most recent report summarizing the 2002 reports from state, nutrients are identified as the leading cause of water pollution in assessed lakes and the second leading cause of pollution in assessed estuaries and bays.[1269] Sediment is the leading cause of pollution in assessed rivers and streams.

Agriculture is the largest known source of water quality impairment to both assessed rivers and streams and lakes and reservoirs.

### 6.2.2 Air Deposition of Nitrogen to Water

Nitrogen oxide (NOx) emissions from fossil fuel combustion from both stationary sources and vehicles can add to the load of nitrogen to waterbodies around the country. Depending on climate and other variables, the atmospheric NOx falls back to the ground as rain, snow, fog, or dry deposition. NOx is deposited directly on waterbodies or falls on the land and can run off to waterbodies. NOx from both stationary sources and vehicles results in significant loadings of nitrogen from air deposition to waterbodies around the country[1270], including the Chesapeake Bay[1271], Long Island Sound[1272], and Lake Tahoe.[1273] The majority of the new biofuel production facilities are expected to be located in the Corn Belt in the Mississippi River Basin, therefore the NOx emissions will add to the nutrient loads to local water bodies and the Gulf of Mexico. Much of the nitrogen deposition from vehicles falls on impervious surfaces, such as roads and parking lots where it runs off into streams. Road drainage systems generally channel runoff quickly and accelerate the nitrogen loadings downstream. In the Chesapeake region, vehicle exhaust remains the single largest source of fossil-fuel derived nitrogen pollution.[1274] Air deposition of nitrogen accounts for more than half of all nitrogen loadings to Lake Tahoe.[1275]

## 6.3 Gulf of Mexico

Production of corn for ethanol may exacerbate existing serious water quality problems in the Gulf of Mexico. Nitrogen fertilizer applications to corn are already the major source of total nitrogen loadings to the Mississippi River.[1276] A large area of low oxygen, or hypoxia, forms in the Gulf of Mexico every year, often called the “dead zone”. Hypoxia threatens commercial and recreational fisheries in the Gulf because fish and other aquatic species cannot live in the low oxygen waters. The primary cause of the hypoxia is excess nutrients (nitrogen and phosphorus) from the Upper Midwest flowing into the Mississippi River to the Gulf. These nutrients trigger excessive algal growth (or eutrophication) resulting in reduced sunlight, loss of aquatic habitat, and a decrease in oxygen dissolved in the water.

The 2008 hypoxic zone was measured at 8,000 square miles, the second largest since measurements began in 1985 and an area the size of Massachusetts.[1277] In 2009 models predicted an even larger hypoxic zone, but it was measured at only 3,000 square miles. A combination of below average high flows on the Mississippi River and winds that mixed Gulf waters are the likely causes of the reduced size of the 2009 zone. The average size of the hypoxic zone over the past five years has been 6,600 square miles.

The Mississippi River/Gulf of Mexico Watershed Nutrient Task Force’s “Gulf Hypoxia Action Plan 2008” lays out two major goals for reducing water quality problems in the Mississippi River/Atchafalaya River Basin: 1) reduce the five-year running average areal extent of the Gulf of Mexico hypoxic zone to 2,000 square miles by 2015 and 2) implement nutrient and sediment reductions to protect public health and aquatic life and reduce negative impacts of water pollution. The Gulf of Mexico Action Plan calls for an acceleration of actions to reduce the hypoxia in the Gulf. In order to meet these goals, the Action Plan calls for a 45% reduction in both nitrogen and phosphorus reaching the Gulf.[1278] EPA's Science Advisory Board (SAB) report to the Task Force said that an additional reduction in nitrogen and phosphorus reduction will be necessary as a result of increased corn production for ethanol and climate change impacts.[1279] The SAB also found that the Gulf of Mexico ecosystem appeared to have undergone a shift so that now the system is more sensitive to nutrient inputs than in the past, inducing a larger response in hypoxia.

Under the Gulf Hypoxia Action Plan, "USDA will encourage the increased use of its nutrient management standard to minimize nutrient loss from fields to help alleviate the impact of increased biofuels production on nutrient loads to the Gulf".[1280] The nutrient management standard requires farmers to account for all plant-available nutrient sources immediately available or rendered available throughout the crop production cycle.

### 6.3.1 Nutrient Loads to the Gulf of Mexico

The U.S. Geological Survey (USGS) has estimated that the spring delivery of nutrients to the Gulf of Mexico in 2008 was among the highest since the early 1980s. Spring nutrient delivery is one of the main factors that control the size of the hypoxic zone. In relation to the long-term spring average, total nitrogen was about 35 to 40% higher (817,000 tons) and total phosphorus was a record 60 to 85% higher (83,000 tons). The large nutrient contributions are primarily due to near record-breaking streamflows in spring 2008 in the Mississippi River Basin. Streamflows were about 50% higher this year compared to the long-term spring average flows since about 1980. Nutrient contributions for a given spring vary depending on the amount of flow in the Mississippi-Atchafalaya River Basin, as well as average stream water nutrient concentrations.

Alexander, et al. modeled the sources of nutrient loadings to the Gulf of Mexico using the USGS SPARROW (spatially referenced regression on watershed attributes) model.[1281] They estimated that agricultural sources contribute more than 70% of the delivered nitrogen and phosphorus. Corn and soybean production alone accounted for 52% of the total nitrogen delivery to the Gulf. Atmospheric deposition was the second largest nitrogen source at 16%. Animal manure on pasture and rangeland are the main sources of phosphorus loadings, contributing 37%. Corn and soybean contributed 25% of the phosphorus; other crops 18%, and urban areas, 12%.

### 6.3.2 Recent Analyses of Impact of Corn Ethanol Production on Nutrient Loadings to the Gulf

Since over 80% of corn grown in the U.S. is produced in the Gulf of Mexico watershed, concern has been expressed about the impact on Gulf hypoxia of increasing corn production for ethanol. Several recent scientific reports have estimated the water quality impact of that increase in corn production. Donner and Kucharik modeled increases in nitrogen export to the Gulf as a result of corn ethanol volumes increasing from 2007 production levels to 15 billion gallons in 2022.[1282] They concluded that the expansion of corn-based ethanol production could make it almost impossible to meet the Gulf of Mexico nitrogen reduction goals without “radical shift” in feed production, livestock diet, and management of agricultural lands. The study estimated a mean dissolved inorganic nitrogen load increase of 10 to18% from 2007 to 2022 to meet the 15 billion gallon corn ethanol goal, depending on the rate of corn yield increases and potential efficiency increases in the conversion of corn to ethanol.

EPA’s Science Advisory Board (SAB) report to the Mississippi River/Gulf of Mexico Watershed Task Force estimated the additional annual nitrogen loadings to the Gulf due to the increase in corn acres from 78.3 million acres in 2006 to 93.7 million acres in 2013.[1283] The SAB estimated that this scenario will result in an additional national annual loading of almost 300 million pounds of nitrogen. An estimated 80% of that nitrogen loading or 238 million pounds will occur in the Mississippi-Atchafalaya River basin and contribute nitrogen to the “dead zone” in the Gulf of Mexico.

## 6.4 Upper Mississippi River Basin Analysis

To provide a quantitative estimate of the impact of this regulation and production of corn ethanol generally on water quality, EPA conducted an analysis that focused on agricultural production in the Upper Mississippi River Basin (UMRB). The UMRB drains approximately 189,000 square miles, including large parts of the states of Illinois, Iowa, Minnesota, Missouri, and Wisconsin. Small portions of Indiana, Michigan, and South Dakota are also within the basin. EPA selected the UMRB because it is representative of the many potential issues associated with ethanol production, including its connection to major water quality concerns such as Gulf of Mexico hypoxia, large corn production, and numerous ethanol production plants.

In 2007, there were approximately 23.7 million acres of corn in the UMRB. About 75% of ethanol production is expected to be in the states in the Corn Belt region, of which the UMRB is a part.[1284] Additional discussion about corn production can be found in Section 1.5.1. On average the UMRB contributes about 39% of the total nitrogen loads and 26% of the phosphorus loads to the Gulf of Mexico.[1285] The Ohio/Tennessee River Basin is the highest contributor of nitrogen loads to the Gulf at 41%. The high percentage of nitrogen from these two basins is primarily due to the large inputs of fertilizer for agriculture and the extensive systems of tile drains. According to USGS, nitrogen loads to the Gulf ranged from 810,000 metric tons to 2.2 million metric tons between 1985 and 2005. Phosphorus loads to the Gulf ranged from 80,700 metric tons to 180,000 metric tons during that same 20-year period.[1286] Although nitrogen inputs to the UMRB in recent years is fairly level, there is a 21% decline in loads to the Gulf. The Science Advisory Board report attributes this decline to higher amount of nitrogen removed during harvest, due to higher crop yields.[1287] However, most of the reduction in the spring was from nitrogen forms other than nitrate. Nitrate is an important nitrogen form fueling the algal growth which leads to hypoxia.[1288] For the same period phosphorus inputs increased 12%.

In 2007, the U.S. produced approximately seven billion gallons of ethanol, mostly from corn kernels. Corn-based ethanol production is expected to reach at least 15 billion gallons in order for industry to comply with the RFS2 standards. Of the potential crops for biofuels production, corn has the highest rates of fertilizer and pesticide application, leading to the concern that higher corn production will result in increased loading of nutrients, pesticides, and sediment to water bodies, including major rivers and estuaries.

### 6.4.1 SWAT Model

EPA selected the SWAT (Soil and Water Assessment Tool) model to assess nutrient loads from changes in agricultural production in the UMRB. Models are the primary tool that can be used to predict future impacts based on alternative scenarios. SWAT is a physical process model developed to quantify the impact of land management practices in large, complex watersheds. SWAT, primarily developed by USDA's Agricultural Research Service and the Texas A&M University Blackland Research and Extension Center, is a public domain model.

EPA determined that SWAT was the most appropriate model to use for this analysis because it has been widely used and validated in watersheds both nationally and internationally.[1289] SWAT has been applied extensively to support water quality and Total Maximum Daily Load (TMDL) planning throughout the United States. SWAT is a basin-scale continuous simulation model that operates on a daily time step and is designed to predict the nonpoint source loadings and resulting water quality impacts of water, sediment, and agricultural chemicals (nutrients and pesticides) from a watershed. The model can assess a wide variety of impacts of alternative management practices and land use changes. The model is physically based, computationally efficient, and capable of continuous simulations over long periods of time, ranging from days to years to decades. Major model components include weather, hydrology, erosion/sedimentation, soil temperature, plant growth, nutrients, pesticides, bacteria, agricultural management, stream routing and pond/reservoir routing.

SWAT has several very important strengths that enabled EPA to develop a robust representation of the hydrology and water quality of the UMRB:

1) Watersheds can be modeled to evaluate the relative impact of changes in management practices, climate, and vegetation on water quality or other variables of interest;

2) SWAT uses readily available inputs commonly available from various government agencies;

3) It can simulate crop and plant communities and provide crop yield and plant biomass, essential to estimate past trends and project accurately into the future;

4) Simulation of very large basins or a variety of management strategies can be performed expeditiously;

5) Long-term impacts spanning several decades can be studied. Time- and climate-variable pollutant contributions can be simulated along with the impact on downstream water bodies spanning several decades; and

6) The model code has been validated on hundreds of basins throughout the United States and abroad.

In addition, prior applications of SWAT for hydrology and nutrient simulation in the UMRB had been completed and were available as a starting foundation for the modeling efforts and focus of this study.[1290] [1291] Further technical information regarding SWAT can be found at: http://www.brc.tamus.edu/swat.

### 6.4.1.1 AEO 2007 Reference Case

In order to assess alternative potential future conditions within the UMRB, such as alternative levels of increased corn production as feedstock for ethanol, we had to establish baseline conditions for SWAT. EPA developed a SWAT model for a reference case using the ethanol fuel volumes predicted in the AEO 2007 report through 2022 to which the results of the RFS1 mandate reference case, and the RFS2 control cases could be compared. As in the NPRM, we selected 2005 as the mid-point of the target period for baseline conditions in the watershed. However, for the analysis for this final rule, we used the 2007 corn yield value to correspond with the agricultural analysis described in Chapter 5. We assumed that 33% of corn produced in the UMRB was converted to corn ethanol, based on estimates from USDA.[1292] This baseline does not include corn ethanol produced as a result of this rulemaking.

Like most water quality modeling, we had to use a range of data sets for the base case scenario inputs. In developing this scenario, it was necessary to select a target year, or window of years, that represent the conditions on the watershed. For this study the year 2005 was selected as the target period for baseline conditions. As with most models of this scale, it was not possible to have all of the data sources come from the exact same time period. It is a common modeling practice to combine the best available data sources for model development in an attempt to characterize the baseline condition within a short time window or period. The majority of the data sources were from the years 2000 through 2006. In addition, selected assumptions about the baseline were made using 2007 as the reference year. In particular, the baseline value for average corn yield (144.2 bushels per acre) was based on the year 2007. In reality, the base case represents watershed conditions within a two to three year period.

Since one of the driving forces in the SWAT model is the water balance, climate data is key to accurately predicting the movement of nutrients and sediment. SWAT was applied (i.e. calibrated) to the UMRB using weather data from the NRCS climatic data center for a 40-year period from 1960 to 2001 and flow and water quality data from 13 USGS gauges on the mainstem of the Mississippi River, spatially distributed from the upper reaches in Minnesota and Wisconsin to the UMRB outlet below Grafton, Illinois. In addition, the weather data has been spatially interpolated to assign one weather station per subwatershed.

To establish the land use for the baseline scenario, SWAT was setup on 131 subwatersheds [8-digit Hydrologic Unit Code (HUC)] for the entire UMRB using the 2001 National Land Cover Data (NLCD)[1293] and Cropland Data Layer (CDL).[1294] The CDL contains crop specific digital data layers, suitable for us in geographic information system applications. The CDL program focuses on classifying corn/soybean/rice/cotton agricultural regions in many of the Midwestern and Mississippi delta states using remote-sensing imagery and on-the-ground monitoring. The USDA-NRCS STATSGO provided the soils data for the entire analyses. The primary input data is the USDA 1997 National Resource Inventory (NRI), which provided land use, soil, and data on management practices on the land.[1295] 1997 is the most current year for which this data is available.

In addition, information from the Conservation Tillage Information Center and USDA-NASS Census of Agriculture 2002/1997 were used to identify the cropping rotation and management practices for the agricultural land areas by these same 131 subwatersheds. Based on the management information at this level, each sub-watershed was assigned appropriate management and tillage practices.

Drainage tiles are one of the critical man-made hydrology structures that changes the natural hydrological cycle significantly at both surface and subsurface (lateral flow) levels. There are no clear records of where the tiles are within the UMRB, other than a few research articles that attempted to estimate the location and extent of the tile drainage coverage. In this study, similar literature values were used to estimate and identify the areas that have the tile system to drain the excess water and nutrients in a timely manner. First, the STATSGO database was used to identify the very poorly drained soils, somewhat poorly drained soils, and poorly drained soils. Then, slope and land use maps were overlaid on these poorly drained soils to identify the potential tile drainage system. Only slopes <1% and agricultural land uses were identified as areas that may potentially be served with tile drainage system.

The tillage practice information in the UMRB was obtained at the county level from Conservation Technology Information Center.[1296] There are five major tillage types. Three of them (no-tillage, ridge-tillage, and mulch-tillage) belong to conservation tillage, and the other two types of tillage (reduced-tillage and intensive-tillage) are non-conservation tillage. The county acreages of this tillage information were overlaid on 8-digit HUCs to estimate the percent of each tillage practices by crop within each HUC.

To estimate nutrient applications on cropland, we started by estimating the livestock and the amount of manure produced. The livestock numbers came from the agricultural statistics for each county based on the 2002 Census of Agriculture for each 8-digit HUC. (Only cattle and hogs numbers were used since they are the dominant livestock types in the UMRB.) Then, the manure production of each 8-digit HUC was obtained through multiplying the number of cattle and hogs and the manure production rates as outlined in ASABE, 2005.[1297] If the total amount of the manure production exceeded 20% of the estimated total fertilizer application in one HUC, manure application and chemical fertilizer application were used as SWAT model inputs to simulate nutrient applications in that HUC. The manure was applied to only those areas that are agricultural land use, even during rotation. For example, only hay, corn, and row crops get manure application, not legume crops such as alfalfa or soybean. So, if an area had a corn and soybean rotation, manure was only applied during the corn growing period. Even when manure was applied, chemical fertilizer was used to supplement the manure application where and when needed. In areas where the manure was not applied, chemical fertilizer was applied to grow the agricultural crops. Chemical nitrogen fertilizer at applied at 1.3 times the amount of nitrogen taken off at harvest.

For the UMRB analysis we used the auto-fertilization feature in SWAT. Any time actual plant growth fell below the specified nitrogen stress threshold, the model automatically applied fertilizer. The user specifies the type of fertilizer, the fraction of total fertilizer applied to the soil surface, the maximum amount of fertilizer that can be applied during the year, the maximum amount of fertilizer that can be applied in any one application, and the application efficiency. Fertilizer is applied to match the difference between soil available nitrogen and the crop yield nitrogen that is removed during harvest. The auto-fertilization used in the UMRB study was set up using default parameter values for fertilizer application rate (200 kg N /ha), maximum per year fertilization rate (300 kg N /ha), application efficiency (1.3, ratio, unitless), and fraction of fertilizer applied to soil surface (0.2). The nitrogen stress factor was set to 0.75 (ratio, unitless).

The 42-year SWAT model runs were performed and the results analyzed to establish runoff, sediment, nitrogen, and phosphorous loadings from each of the 131 8-digit HUC subwatersheds and the larger 4-digit subbasins, along with the total outflow from the UMRB and at the various USGS gage sites distributed along the Mississippi River mainstem. These results provided the Reference Case model values to which the RFS1 and RFS2 future alternatives are compared.

The current national average for corn yield of 150 bushels per acre (bu/ac) was used to establish baseline yield levels. The baseline average yield for the UMRB was established at 144.2 bushels per acre. This baseline yield is due to the significant amount of crop area in northern states where yield values are lower than the national average. National average corn yields have been increasing primarily due to favorable weather conditions and improvement in practices to reduce stress on the corn plants from excess water, drought, and pests.

### 6.4.1.2 Reference Cases and RFS2 Control Case

To assess the impacts of the increased use of corn ethanol, we modeled an RFS2 control case and compared it to both the AEO2007 reference case and the RFS1 mandate reference case. For the AEO2007[1298] reference case we modeled: 10.49 billion gallons a year (BGY) in 2010, 11.1 BGY in 2015, 11.83 BGY in 2020, and 12.29 BGY in 2022. For the RFS1 mandate reference case we modeled a constant national ethanol goal of 7.05 billion gallons a year (BGY) starting in 2012. For this analysis, the reference cases assumed that no cellulosic ethanol was produced from corn stover. For the RFS2 control case we modeled a steadily increasing volume of corn ethanol in keeping with the EISA standards; 11.24 BGY in 2010, 14.79 BGY in 2015, and 15 BGY in 2016 and beyond. We were not able to model the impacts of corn stover removal at this time, so the analysis only reflects the impacts of increased use of corn grain for renewable fuel use.

For SWAT analyses of these three scenarios, national corn ethanol volumes were adjusted for the UMRB based on a 42.3% ratio of ethanol production capacity within the UMRB compared to national capacity. This fraction was determined by overlaying coverage of nationwide ethanol plants with a coverage of the UMRB. Production from ethanol plants within the study area were totaled and then divided by the nationwide production. Both current production and planned expansion were included in the totals. Ethanol location and production information were taken from the Renewable Fuels Association table of ethanol refinery locations in April 2008.[1299] We assumed an average of 2.7 gallons of ethanol per bushed of corn and a moisture content of 20% when converting corn grain mass to bushels. The resulting UMRB ethanol production goals were converted into the corresponding required corn production acreage, i.e. the extent of corn acreage needed to meet those ethanol production goals.

The SWAT model was run with the available input climate record, 1960-2001, with the model run under conditions of the increased corn production and yields noted above. Separate model runs were performed for each of the three projection years, and the model results were analyzed to provide loadings for comparison with the baseline loadings.

#### 6.4.1.2.1 Corn

Increases in corn yield were built into the future scenarios, with an annual increase of 1.23%. This produced yield increases to 149.6 bushels per acre (bu/ac) (3.7% in 2010), 159 bu/ac (10.3% in 2015), 169 bu/ac (17.2% in 2020), and 173.2 bu/ac (20.1% in 2022). Table 6.4-1 shows the corn acreage in the Upper Mississippi River Basin for each case. Corn acres increased 9% in 2022 between the AEO 2007 case and the RFS2 (no stover) cae.

**Table 6.4-1.**
**Corn Acres in the Upper Mississippi River Basin for**
**AEO 2007, RFS1, and RFS2 Cases (millions of acres)**

| | AE0 2007 | RFS1 | RFS2 (no stover) |
|---|---|---|---|
| 2010 | 26.83 | 23.65 | 27.61 |
| 2015 | 26.78 | 22.78 | 30.40 |
| 2020 | 26.80 | 22.35 | 29.73 |
| 2022 | 26.96 | 22.20 | 29.40 |

#### 6.4.1.2.2 RFS2 (No Stover) Control Case Pollutant Loadings

Tables 6.4-2 through 6.4-4 compare the model outputs for nitrogen, phosphorus, and sediment between the AEO 2007 Reference Case and the RFS2 (no stover) Case scenarios for the years 2010, 2015, 2020, and 2022. Land load is the total amount of nitrogen or phosphorus that reaches a stream within the UMRB. The total outflow is the remaining amount measured at the outlet of the UMRB at Grafton, Illinois after accounting for in-stream loses due to uptake or assimilation.

These results only estimate loadings from the Upper Mississippi River basin, not the entire Mississippi River watershed. As noted earlier, the UMRB contributes about 39% of the total nitrogen loads and 26% of total phosphorus loads to the Gulf of Mexico. The decreasing nutrient load over time is likely attributable to the increased average corn yield per acre, resulting in greater plant uptake of nitrogen and fewer corn acres planted for ethanol production goals in this rule.

### Table 6.4-2.
### Average annual nitrogen loads: Comparison of AEO 2007 Reference Case to the 2022 RFS2 (No Stover) Case (% difference in parentheses)

| | AEO 2007 Reference Case | | RFS2 (No Stover) Case | |
|---|---|---|---|---|
| Model Run | Total Land Load, million lbs | Total Outflow, million lbs | Total Land Load, million lbs | Total Outflow, million lbs |
| 2010 | 1948 | 1470 | 1944 (-0.21) | 1467 (-0.20) |
| 2015 | 1911 | 1441 | 1946 (1.83) | 1469 (1.94) |
| 2020 | 1887 | 1421 | 1912 (1.32) | 1442 (1.48) |
| 2022 | 1877 | 1413 | 1897 (1.07) | 1430 (1.20) |

Approximately 24 to 25% of nitrogen leaving agricultural fields was either taken up by aquatic plants or volatilized before reaching the outlet of the UMRB at Grafton, Illinois. Even though much of the nitrogen that is volatilized from streams and rivers and near-coastal waters is removed from the total loading to water, it is not necessarily eliminated as an environmental concern. Conversion of the nitrate to nitrogen gas through denitrification is generally an incomplete chemical process. 5% or more of the nitrogen can be converted to nitrous gas, a powerful greenhouse gas that is 300 times the climate-warming potential of carbon dioxide, the major greenhouse gas of environmental concern. Thus, a water pollutant becomes an air pollutant until it is either captured through biological sequestration or converted fully to elemental nitrogen.

The scenarios showed an increase in phosphorous loads at a slightly lower percentage than nitrogen.

### Table 6.4-3.
### Average annual phosphorus loads: Comparison of AEO 2007 Reference Case to the 2022 RFS2 (No Stover) Case (% difference in parentheses)

| | AEO 2007 Reference Case | | RFS2 (No Stover) Case | |
|---|---|---|---|---|
| Model Run | Total Land Load, million lbs | Total Outflow, million lbs | Total Land Load, million lbs | Total Outflow, million lbs |
| 2010 | 180.0 | 133.8 | 179.9 (-0.06) | 133.7 (-0.07) |
| 2015 | 178.2 | 132.3 | 179.6 (0.79) | 133.6 (0.98) |
| 2020 | 177.0 | 131.3 | 178.2 (0.68) | 132.4 (0.84) |
| 2022 | 176.5 | 130.9 | 177.6 (0.62) | 131.8 (0.69) |

Total sediment outflow showed very little change over all scenarios. This result is primarily due to corn stover remaining on the field following harvest and therefore reducing sediment transport to water.

**Table 6.4-4.**
**Average annual sediment loads: Comparison of AEO 2007 Reference Case to the 2022 RFS2 (No Stover) Case (% difference in parentheses)**

|  | **AEO 2007 Reference Case** | **RFS2 (No Stover) Case** |
|---|---|---|
| Model Run | Total Outflow, million tons | Total Outflow, million tons |
| 2010 | 6.231 | 6.232 (0.02) |
| 2015 | 6.221 | 6.233 (0.19) |
| 2020 | 6.214 | 6.224 (0.16) |
| 2022 | 6.211 | 6.220 (0.14) |

#### 6.4.1.2.3 RFS1 Mandate Reference Case Pollutant Loadings

Tables 6.4-5 through 6.4-7 compare the models outputs for nitrogen, phosphorus, and sediment between the RFS1 Mandate Reference Case and the RFS2 (No Stover) Case scenarios for the years 2010, 2015, 2020, and 2022. Land load is the total amount of nitrogen or phosphorus that reaches a stream within the UMRB. The total outflow is the remaining amount measured at the outlet of the UMRB at Grafton, Illinois after accounting for in-stream loses due to uptake or assimilation.

**Table 6.4-5.**
**Average annual nitrogen loads: Comparison of RFS1 Mandate Reference Case to the RFS2 (No Stover) Case (% difference in parentheses)**

|  | **RFS1 Mandate Reference Case** |  | **RFS2 (No Stover) Case** |  |
|---|---|---|---|---|
| Model Run | Total Land Load, million lbs | Total Outflow, million lbs | Total Land Load, million lbs | Total Outflow, million lbs |
| 2010 | 1878 | 1414 | 1944 (3.5) | 1467 (3.7) |
| 2015 | 1838 | 1382 | 1946 (5.8) | 1469 (6.3) |
| 2020 | 1806 | 1357 | 1912 (5.9) | 1442 (6.3) |
| 2022 | 1794 | 1347 | 1897 (5.7) | 1430 (6.2) |

**Table 6.4-6.**
**Average annual phosphorus loads: Comparison of RFS1 Mandate Reference Case to the RFS2 (No Stover) Case (% difference in parentheses)**

| | **RFS1 Mandate Reference Case** | | **RFS2 (No Stover) Case** | |
|---|---|---|---|---|
| Model Run | Total Land Load, million lbs | Total Outflow, million lbs | Total Land Load, million lbs | Total Outflow, million lbs |
| 2010 | 175.6 | 130.1 | 179.9 (2.4) | 133.7 (2.8) |
| 2015 | 173.5 | 128.4 | 179.6 (3.5) | 133.6 (4.0) |
| 2020 | 171.6 | 126.9 | 178.2 (3.8) | 132.4 (4.3) |
| 2022 | 170.8 | 126.3 | 177.6 (4.0) | 131.8 (4.4) |

**Table 6.4-7.**
**Average annual sediment loads: Comparison of RFS1 Mandate Reference Case to the 2022 RFS2 (No Stover) Case (% difference in parentheses)**

| | **RFS1 Mandate Reference Case** | **RFS2 (No Stover) Case** |
|---|---|---|
| Model Run | Total Outflow, million tons | Total Outflow, million tons |
| 2010 | 6.190 | 6.232 (.07) |
| 2015 | 6.187 | 6.233 (.07) |
| 2020 | 6.178 | 6.224 (.07) |
| 2022 | 6.174 | 6.220 (.07) |

#### 6.4.1.2.4 Case Study

To evaluate local water quality impacts that are impossible to ascertain at the scale of the UMRB, we also modeled the Raccoon River watershed in central Iowa. The criteria for choosing this watershed included: percentage of corn area representative of the UMRB, stream segments included in EPA’s 303(d) list of impaired waters due to high nutrient levels, biorefinery plants, drinking water intakes, and observed streamflow and water quality data. Nearly 88% of the watershed is in agriculture. 75% of the watershed produces corn and soybeans, mostly in rotation. Hay and other row crops are produced on the remaining agriculture land. The city of Des Moines makes up about 8% of the watershed. The state of Iowa has listed numerous stream segments of the Raccoon River as impaired. In particular, the two stream segments from the confluence of the North and South branches of the Raccoon River to the watershed’s outlet were listed in 2006 for having more than 25% of the collected water samples exceed the drinking water standard for nitrate.

As part of the UMRB and by itself, the Raccoon River has been the focus of numerous modeling studies. As a result, there is a substantial amount of observed data throughout the watershed, primarily from the U.S. Geological Survey gaging stations.

The case study used the same assumptions and scenarios as those used for the UMRB analysis. SWAT-simulated streamflow and water quality (total nitrogen and phosphorus, and sediment loadings) were calibrated against observed data at both monthly and yearly time steps.

As in the UMRB study, nitrogen loads to water increased for the future scenarios, though at a greater rate. Future phosphorus loads decreased in the Raccoon River model, where they had shown minor increases in the UMRB model. For the Raccoon River, there was a greater decrease in sediment load, which is the likely cause for the decrease in phosphorus loadings. As with the UMRB model, there was minimal change in streamflow.

### 6.4.1.5 Sensitivity Analysis

Using the existing UMRB SWAT model, a sensitivity analysis was conducted on a number of important meteorological and management related factors. The goal was to further understand the model characteristics and sensitivities to parameters and input forcing functions that control the model response for the key environmental indicators of concern. Scenarios were constructed using four factors: fertilization application threshold, corn residue removal, daily air temperature, and daily precipitation. The results of the analysis showed that rainfall and temperature are the most influential factors for all model outputs: water yield, total nitrogen and phosphorus loadings, and sediment loadings. These results underscored the importance of representing these two driving factors accurately in hydrologic modeling. Corn residue removal noticeably reduced nutrient loading into streams while increasing sediment loads. However, since corn residue is the main source of organic nitrogen and phosphorus, the removal of the residue leads to the need for higher nutrient inputs in the growing season. The fertilization application threshold scenario did not tangibly impact water yield and sediment loading. The findings from this study indicated that future climate change could greatly influence water availability and pollution from corn cropland.

## 6.5 Climate Change Impacts

Although climate change is expected to be an important factor in future crop production in the Upper Mississippi River Basin, EPA has not modeled the impact of climate change on corn yields for a variety of reasons. Climate change requires a long period of observation. Over the short time frame reflected in this proposal, precipitation and temperature increases will be small and indistinguishable from the natural variability of the climate.

Crop yield changes resulting from climate change depend on the atmospheric carbon dioxide level, the crop, and the base temperature. Yield also depends on the characteristics of the crop relative to the timing of precipitation and of extreme temperature events. All of these variables make an estimation of actual climate-induced yield loss very difficult to develop. Farmer adaptation may mitigate the effects of climate change on agriculture to some degree. Adaptations are influenced by many unpredictable factors, including government policy, prices, research and development, and technical assistance. Climate model simulations generally indicate that most locations in the upper Midwest will warm more than the global average and will receive more precipitation than current – though estimates vary considerably depending on the model used and initial conditions.

## 6.6 Chesapeake Bay Watershed

The Chesapeake Bay Commission and others have expressed concerns about the water quality impact of increased corn production for ethanol may have on the Chesapeake Bay.[1300, 1301] The Chesapeake Bay watershed stretches across more than 64,000 square miles, encompassing parts of six states--Delaware, Maryland, New York, Pennsylvania, Virginia and West Virginia—and the entire District of Columbia. The Chesapeake's land-to-water ratio (14:1) is the largest of any coastal water body in the world. This is why land use and land management have such significant influences on the health of the Bay. In its annual State of the Bay report in 2007, the Chesapeake Bay Foundation gave the Bay a score of 28 on a scale where 70 means the Bay is "saved" and 100 is pristine. The Foundation said that "the health of the Chesapeake Bay is dangerously out of balance".[1302]

In 2000, Chesapeake Bay Program partners (states, federal agencies, universities, nongovernmental agencies) agreed to reduce nitrogen pollution from an estimated 285 million pounds per year to no more than 175 million pounds by 2010. Similarly they pledged to reduce phosphorus from about 19 million pounds per year to less than 13 million pounds. While there have been steady declines in nitrogen and phosphorus, they have not been adequate to meet the established goals. The watershed must essentially quadruple the pace of the Bay cleanup to meet the 2010 commitment. To restore water quality in the Bay, all of the basin's more than 87,000 farms will need to implement best management practices (BMPs) at levels never before seen in this country. The states have committed to implement close to 30 different agricultural BMPs as part of their restoration strategies.

In May 2009, President Obama issued Executive Order 13508 on Chesapeake Bay Restoration and Protection. The order established a Federal Leadership Committee, chaired by EPA, and with senior representatives from the departments of Agriculture, Commerce, Defense, Homeland Security, Interior, and Transportation. In November 2009, these federal agencies released a draft strategy which contains a range of approaches for accelerating cleanup of the nation's largest estuary and its vast watershed.[1303] The draft strategy calls for increased accountability and performance from pollution control, habitat protection and land conservation programs at all levels of government, including an expanded use of regulatory authorities to address pollution control and additional voluntary and market-based solutions – particularly when it comes to habitat protection and land conservation programs. The proposed actions are in response to overwhelming scientific evidence that the health of the Chesapeake Bay remains exceptionally poor, despite the concerted restoration efforts of the past 25 years.

Agricultural lands account for nearly a quarter of the watershed, and contribute more nutrients to the Bay than any other land use. Agricultural operations produce about 41% of the nitrogen and 47% of the phosphorus loads going to the Bay. Agriculture also contributes about 63% of the Bay's sediment. Municipal and industrial wastewater treatment plants throughout the watershed are responsible for 21% of the total nitrogen pollution and 22% of the total phosphorus pollution delivered to the Bay.

At least 25% and possibly a third of the nitrogen entering the Bay comes from air deposition. The principal sources of emissions are power plants, cars and trucks, agriculture, and off-road sources such as construction equipment, lawn mowers and aircraft. While population increased about 8% during the last decade, vehicle miles traveled rose 26%. More discussion about nitrogen oxides emission impacts can be found in Chapter 3.2.

The Bay watershed receives significant levels of nitrogen oxides and other airborne pollutants from its large airshed (which is about six and a half times the size of the watershed), as far west as Ohio and Indiana. Air deposition of nitrogen on the land adds to the burden that must be dealt with by farmers, local governments and other landowners.

### 6.6.1 Agricultural Production Effects

Due to the significant acreage within the Chesapeake Bay watershed that is devoted to agricultural production (approximately 22%), increases in corn acreage can potentially contribute to changes in nutrient loads to the Bay. High demand for corn reflected in record corn prices have played a substantial role in encouraging producers to alter their typical crop production rotations and crop acreage, contributing to noteworthy changes in crop acreages across the watershed. A technical review committee convened by the Chesapeake Bay Commission estimated that 300,000 new acres of corn could be added in the Bay watershed in the coming years.[1304] This new corn acreage could potentially contribute an additional five million pounds of nitrogen to the Bay. The Bay Program partners are trying to reach a 90 million pound reduction in nitrogen from all sources. However, it is estimated that 17 million pounds of nitrogen could be offset if all agriculture acres used cover crops as a conservation practice after harvest.

Strong market forces also encourage agricultural operators to increase grain production possibly by increasing the conversion of non-row crop acreage (hay, pasture and fallow or idle lands) to row crop production. Grain row crops can add more nutrients per acre to the Bay than hay and pasture due to production intensity, management systems, and nutrient efficiency of the crop.

#### 6.6.1.1 Base Analysis Assumptions

The Chesapeake Bay Program Watershed Model Phase 4.3 (CBWM) and Vortex were utilized in the analysis of potential shifts in nutrient loading to the Bay based on reported changes to agricultural crop production from 2005 to 2008. These agricultural production changes are partially the result of the rapid expansion of biofuel production within the United States, supported by market-driven commodity price increases, government policies, or a combination of both. The CBWM is a dynamic watershed model used to characterize nutrient and sediment loads, and changes in these loads, due to management actions for decision support.[IIIIIIIIIIIIII]

In developing the agricultural production trend analysis within the Chesapeake Bay watershed, the USDA's National Agricultural Statistics Service's (NASS) 2007 and 2008 Projected Plantings report on reported crop acreages was modified to target only the Bay watershed.

#### 6.6.1.2 Corn Production Analysis

Analyzing corn production acreage figures for the period from 2005 to 2008 from the NASS 2007 and 2008 Projected Planting reports, a measurable upward trend was evident for corn acreage plantings across the Bay watershed over the analysis period. This upward trend increased sharply between 2006 and 2007 and decreased for the 2007 and 2008 period. Despite the recent downward trend, total corn acreage increased over the analysis period by almost 66,000 acres.

#### 6.6.1.3 Corn Nutrient Load Analysis

Employing a modeled analysis of the USDA-NASS Prospective Plantings report using the Chesapeake Bay Watershed Model Version 4.3 and Vortex, considerable increases of potential nitrogen loads to the Bay are associated with increased corn acreage. The decrease of corn acreage in the 2007 to 2008 period does not offset the total increase in acreage and nitrogen yields between 2005 and 2008. Total nitrogen loads increased by almost 2.4 million pounds.

#### 6.6.1.4 Land Use Conversion Analysis

The agricultural production trends between 2005 and the present not only indicate an overall increase in the number of acres under corn production, but also an increase in the total acres of land under row crop production by over 355,000 acres. Since agricultural land uses within the Chesapeake Bay watershed are continuously decreasing due to urban development, the increase in row crop acreage may come at the expense of other cropping systems, or agricultural land uses such as hay, pasture or idle lands.

#### 6.6.1.5 Land Use Conversion Nitrogen Load Analysis

The USDA-NASS Prospective Plantings reports and the Chesapeake Bay Program Watershed Model indicate a continuous total conversion of non-row crop agricultural lands over the period from 2005 to 2008 to more intensive row crop production. The non-row crop land uses typically produce less nitrogen yields to the Bay, thus additional acres converted to grain production can also increase nitrogen loads significantly. This analysis estimates that nitrogen loads increase by 8.8 million pounds.

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[IIIIIIIIIIIIII] For more information on the CBWM see http://www.chesapeakebay.net/model.htm

If time and resources allow, the Chesapeake Bay Program proposes to analyze the potential impacts within the Chesapeake Bay watershed of the implementation of the RFS2 for the FRM using available systems and models at our disposal. The models that would potentially be used in the analysis would include Phase 5.2 of the Chesapeake Bay Watershed Model (CBWM), the Nutrient and Sediment Scenario Builder (NSSB), the Chesapeake Bay Estuarine Water Quality Sediment Transport Model (CBEWQSTM) and the Chesapeake Bay Land Change Model (CBLCM). The CBWM is a dynamic watershed model used to characterize nutrient and sediment loads, and changes in these loads, due to management actions for decision support. The NSSB is being developed to determine nutrient and sediment loads under multiple land uses and crop types with variable organic and inorganic nutrient inputs. The CBEWQSTM determines the effects of nutrient and sediment load changes to the attainment of water quality standards. The CBLCM simulates changes in land use as a result of locally projected increases in population out to the year 2030.

The scope of the analysis is proposed to include incremental and delivered nitrogen, phosphorus and sediment to the Chesapeake Bay, and the effect of management changes to the attainment of water quality standards.

## 6.7 Ethanol Production and Distribution

Under the Clean Water Act, all point sources of pollution, including ethanol plants, must have a permit to discharge to water bodies or to municipal wastewater treatment plants for both industrial process water and stormwater. The permit regulates the amount of pollutants that can be discharged. There are three principle sources of discharges to water from ethanol plants: reject water from water purification, cooling water blowdown, and off-batch ethanol.

### 6.7.1 Water Discharges

Water is required at ethanol facilities for processing and for the production of steam that is typically used in biomass pretreatment and ethanol distillation processes. An ethanol plant's wastewater is typically comprised of cooling tower blowdown, boiler blowdown, and water softener discharge. The majority of the process water is lost as steam in the distillation process. In addition, stormwater runoff from the facility may be contaminated from precipitation (rain or snow) coming in contact with plant operations (industrial plant yards, material and waste handling, storage areas, shipping and receiving areas, residuals sites) and requires adequate control and management.[1305]

While some ethanol facilities get their process water from municipal water supplies, most use on-site wells to produce the process water for the ethanol process. Most groundwater sources are not suitable for process water because of their mineral content. Therefore, the water must be treated for use in ethanol production. The most common method of groundwater treatment is reverse osmosis. Reverse osmosis uses specialized filtration and pressure to produce pure water while concentrating the groundwater minerals into reject water. The minerals in the reject water are site-specific, but they can include: calcium carbonate, magnesium carbonate, sulfate, iron, and sodium. For every two gallons of pure water produced, about a gallon of brine is discharged as reject water. Most estimates of water consumption in ethanol production are based on the use of clean process water and neglect the water discharged as reject water.

The largest source of wastewater discharge is reverse osmosis reject water from process water purification. The reverse osmosis process concentrates groundwater minerals to levels where they can have water quality impacts. The concentrated minerals can show toxicity due to osmotic concentration and the presence of some ions such as sulfate or copper. There is really no means of “treating” these ions to reduce toxicity, other than further concentration and disposal, or use of in-stream dilution. Some facilities have had to construct long pipelines to get access to dilution so they can meet water quality standards.

Ethanol plants also discharge cooling water blowdown, where some cooling water is discharged to avoid the buildup of minerals in the cooling system. These brines are similar to the reject water described above. In addition, if off-batch ethanol product or process water is discharged, the waste stream can have high Biochemical Oxygen Demand (BOD) levels. BOD directly affects the amount of dissolved oxygen in rivers and streams. The greater the BOD, the more rapidly oxygen is depleted in the stream. This means less oxygen is available to higher forms of aquatic life. The consequences of high BOD are the same as those for low dissolved oxygen: aquatic organisms become stressed, suffocate, and die.
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Ethanol production facilities are important transportation hubs. For instance, a facility in Iowa produces about 130 million gallons of ethanol in a year. On an average workday, 175 tractor-trailers bring in corn, ethanol goes out in 12 rail tankers, and 8 rail cars are filled with dried distillers grain to be used as animal feed. This intensity of vehicle travel can have local water impacts from stormwater runoff, spills, etc. similar to any other rail and trucking terminal.

### 6.7.2 Water Use

Older generation production facilities used 4-6 gallons of process water to produce a gallon of ethanol, but newer facilities use less than 3 gallons of water in the production process. Most of this water savings is gained through improved recycling of water and heat in the process: the conservation of heat energy and water go hand-in-hand. This energy savings is a key economic advantage for newer plants. A gallon of ethanol contains about 70,000 Kcal of energy. Older plants used 35-40,000 Kcal of energy to produce a gallon of ethanol, but newer facilities use only 25-28,000 Kcal per gallon.

The abundance or lack of water supply is a local issue, and there have been concerns with water consumption as new plants go online. Some facilities are tapping into deeper aquifers as a source of water. These deeper water resources tend to contain higher levels of minerals and this can further increase the concentration of minerals in reverse osmosis reject water.

### 6.7.3 Distillers Grain with Solubles

One important co-product of ethanol production is distillers grain with solubles (DGS). Due to the increase in ethanol production and the price of corn, DGS has become an increasing important feed component for confined livestock. About one-third of the corn processed into ethanol is converted into DGS. Therefore approximately 45 million tons of DGS will be produced for the 15 billion gallons of corn ethanol produced by 2015. Concerns have been raised about the relatively higher phosphorus content of DGS compared to traditional feeds.

Livestock producers may partially replace corn or other feeds with DGS for both economic and production reasons. Different livestock species can tolerate varying amounts of DGS in their diets. The majority of DGS are fed to beef and dairy cows. Current recommendations allow beef and dairy cows diets to include from 15 to 40% DGS. Recommendations for poultry and swine diets are generally less than 15% DGS. Although specific analysis of DGS can vary between ethanol plants, compared to corn, DGS are higher in crude protein (nitrogen) and three to four times higher in phosphorus.[1306]

The increase in nitrogen and phosphorus from DGS in livestock feed has potential implications for water quality. When nitrogen and phosphorus are fed in excess of the animal's needs, these nutrients are excreted in the manure. Most livestock manure is applied to crops, especially corn, as a source of nutrients. When manure is applied at rates above the nutrient needs of the crop or at times the crop can not use the nutrients, the nitrogen and phosphorus can runoff to surface waters or leach or ground waters. Excess nutrients from manure nutrients have the same impact on water quality as excess nutrients from other sources.

Several recent studies have indicated that DGS may have an impact on food safety. Cattle fed DGS have a higher prevalence of a major food-borne pathogen, E. coli O157, than cattle without DGS in their diets.[1307] More research is needed to confirm these studies and devise methods to eliminate the potential risks.

Livestock producers can limit the potential pollution from manure applications to crops through a variety of techniques. USDA's Natural Resources Conservation Service (NRCS) has developed a standard for a comprehensive nutrient management plan (CNMP) to address the issue of proper use of livestock manure.[1308] Agricultural producers who use manure should test the nitrogen and phosphorus content before application of the manure. Due to the substantially higher phosphorus content of manure from livestock fed DGS, producers will potentially need significantly more acres to apply the manure so that phosphorus will not be applied at rates above the needs of the crops. This is a particularly important concern in areas where concentrated livestock production already produces more phosphorus in the manure than can be taken up by crops or pasture land in the vicinity.

### 6.7.4 Water Quality Impact from Ethanol Leaks and Spills

The potential for exposure to fuel components and/or additives can occur when underground fuel storage tanks leak fuel into ground water that is used for drinking water supplies or when spills occur from above ground tanks or distribution systems that contaminate surface drinking water supplies or surface waters. Additionally, in surface waters, rapid biodegradation of ethanol can result in depletion of dissolved oxygen with potential mortality to aquatic life.

Regarding leaks or spills and drinking water impacts, ethanol biodegrades quickly and is not necessarily the pollutant of greatest concern in these situations. Instead, ethanol's high biodegradability shifts the subsurface geochemistry, which can cause reduced biodegradation of benzene, toluene, and xylene (up to 50% for toluene and 95% for benzene).[1309] The plume of BTEX (benzene, toluene, ethylbenzene and xylenes) compounds in gasoline from a fuel spill can extend as much as 70% farther in groundwater and can persist longer, thereby increasing potential human exposures to these compounds.[1310] Particularly large plumes of benzene can be expected when: there is a large area of the aquifer that is contaminated with liquid phase gasoline; the background concentration of sulfate-reducing bacteria (which biodegrade ethanol and benzene) in the ground water is low; the rate of ethanol biodegradation is low; and the flow velocity of the ground water is high. More detail on ethanol biodegradation and a summary of laboratory and field studies of ethanol spills will be forthcoming in the EPAct 2005 Report to Congress on Fuel Additive Replacements for MTBE in 2010.

Ethanol leak and spills from the approximately 600,000 gas stations in the U.S, could have a significant impact on water quality and drinking water supplies. Urban areas, that rely on ground water for drinking water would be affected most, especially where are existing water shortages

With the increasing use of ethanol in the fuel supply nationwide, it is important to understand the impact of ethanol on the existing tank infrastructure. Federal regulations require that underground storage tank (UST) systems be compatible with the fuel stored. Because much of the current underground storage tank equipment was designed and tested for use with petroleum fuels, there may be many UST systems currently in use that contain materials that are incompatible with ethanol blends greater than 10%. Combined with the fact that ethanol is more corrosive than petroleum, there is concern regarding the increased potential for leaks from existing distribution systems, terminals and gas stations and subsequent impacts on water supplies. Given the practical challenges of determining the age and materials of underground storage equipment at approximately 233,000 federally regulated facilities, it may be difficult or impossible to confirm the compatibility of current underground storage tanks and other tank-related hardware with ethanol blends. Further discussion of challenges in retail distribution are discussed in Section 1.6 of the RIA.

In 2007, there were 7,500 reported releases from underground storage tanks. Since approximately 50% of the gasoline used in the U.S. contains ethanol, approximately 3,750 of those releases likely contained some amount of ethanol. Therefore, EPA is undertaking analyses designed to assess the potential impacts of ethanol blends on tank infrastructure and leak detection systems and determine the resulting water quality impacts.

An additional hazard from spills from fuels containing ethanol is risk of potential explosions. Laboratory and field studies have found biodegradation of ethanol can produce concentrations of methane in excess of the water solubility of methane (i.e., more methane was produced than could be dissolved by the available water). This methane could bubble out of the ground water and enter the soil gas at explosive concentrations, although it is not possible to quantify the risk at this time. EPA is beginning development of modeling software for the assessment of fuels of varying composition on ground water, with simulation of methane production being one component of this work.

## 6.8 Water Use and Wastewater from Biodiesel Plants

Biodiesel plants use much less water than ethanol plants in production of biofuel. Water is not used in conversion of oil to biodiesel, but is used for washing impurities from the finished product. Water use is variable, but is usually less than one gallon of water for each gallon of biodiesel produced. Larger well-designed plants use water more sparingly, while smaller producers and hobbyists use more water. Some facilities recycle washwater, which reduces water consumption.

The strength of process wastewater from biodiesel plants is highly variable. Most production processes produce washwater that has very high BOD levels. Essentially the strength of the wastewater is based on glycerin and methanol content. Larger facilities are segregating glycerin as a side product and have efficient methanol recovery, while smaller plants are more likely to dispose of glycerin, excess methanol, and washwater as a single waste stream. Crude glycerin is an important side product from the biodiesel process and has many uses. It is about 10% of the final product. Although there is a commercial market for glycerin, the rapid development of the biodiesel industry has caused a glut of glycerin production and many facilities dispose of glycerin.

The high strength of these wastes can overload and disrupt the biological processes in municipal treatment plants. The normal wastewater going into a municipal sewage treatment plant has a BOD 200mg/l. Washwater from the biodiesel process with efficient recovery of methanol, containing small amounts of glycerin, can have a BOD of 10,000 – 15,000 mg/L. Pure glycerin has a BOD of nearly 1,000,000 mg/L. There have been several cases of wastewater treatment plant upsets due to these shock loadings from releases of glycerin from biodiesel production facilities. Unfortunately, these have been due to slug loadings to small wastewater treatment plants. Other states such as Illinois and Alabama have also had problems with discharges from small biodiesel plants. In addition, there have been incidences of outright dumping of glycerin. One such event resulted in a large fish kill in Missouri.

Producers that choose to dispose of glycerin can be regulated under several EPA programs, depending on the practice. EPA strongly supports the beneficial use of glycerin as a product. While the market for refined glycerin is glutted with an excess supply, there are many known uses for glycerin feedstock. As prices for glycerin go down, many of these known products will show a better profit margin and demand for glycerin will increase. Most larger facilities are segregating crude glycerin for refining into usable feedstock for other products. Refining can range from minimal processing up to creation of a food grade product. Nationally, there is a lot of research on the creation of new value added products (ethanol, propylene glycol, etc.) using glycerin as a feedstock. Most of these projects are in university labs, but a few are up to pilot scale. These new technologies will go online at full scale within the next few years, and are an important part of the profit stream for the industry.

## 6.9 Potential Impacts to Drinking Water and Public Health

Under the Safe Drinking Water Act (SDWA), EPA establishes enforceable safety standards for drinking water provided by public water systems (PWS). For chemicals, the standard is typically called a maximum contaminant level (MCL). A PWS is “a system for the provision to the public of water for human consumption through pipes or other constructed conveyances, if such system has at least fifteen service connections or regularly serves at least twenty-five individuals.” If the source water for a PWS does not meet the MCL, the PWS must take measures to reduce the contamination to safe levels and that may entail installing expensive drinking water treatment technology e.g., ion exchange (IE), granulated activated carbon (GAC) or reverse osmosis (RO).

EPA anticipates that increased corn production for ethanol will increase the occurrence of nitrate, nitrite, and atrazine in sources of drinking water. New corn acreage may result in increase in the application of fertilizers and herbicides, especially on marginal lands that are not as productive. The ethanol production process may generate new or increased discharges, injection or infiltration of process waste water that could adversely affect the nation’s surface water and ground water used for drinking water.

In addition to potential additional contamination of sources of drinking water, surface and ground water supplies may be strained by increased production of irrigated corn for ethanol and the ethanol production process itself in local and regional areas. Increased pumping from agricultural aquifers to support ethanol production may accelerate the long running depletion of aquifers which has been documented by the USGS. According to U. S. Geological Survey (USGS) data, more than 72 billion gallons a day are already being pumped from the “thirty regional principle aquifers with the greatest amount of ground water use”, with irrigation accounting for slightly more than 75% of those withdrawals.[1311] The water table of the Ogallala aquifer has declined by over 150 feet in some areas since the 1950s due to increasingly large withdrawals.[1312] Aquifers provide water for domestic and other uses, and contribute to the base flow of many streams and lakes that support aquatic habitats and other ecosystem services such as fishing and swimming. Lower stream levels combined with the increased pollutant loadings may concentrate pollutants. Higher pollutant concentrations may require increased drinking water treatment. The accelerated depletion of agricultural aquifers and surface water supplies may be exacerbated by an increase in the incidence of droughts that are predicted under many climate change scenarios.

### 6.9.1 Nitrogen

The nitrogen fertilizers that are applied to corn and other agricultural crops can end up in drinking water sources where they can impact human health. The two nitrogen compounds of concern are nitrate and nitrite. Nitrate is the most stable form of nitrogen in water.

EPA has established the MCL for nitrate-nitrogen at 10 parts per million (ppm) and for nitrite at 1 ppm. Infants below six months who drink water containing nitrate and/or nitrite in excess of the MCL could become seriously ill and, if untreated, may die.[1313] Symptoms include shortness of breath and blue baby syndrome. This health effects language is not intended to catalog all possible health effects for nitrate. Rather, it is intended to inform people of the most significant and probable health effects, associated with nitrate and nitrite in drinking water.

Most nitrogen in water is converted to nitrates. Since nitrates are very soluble and do not bind to soils, they have a high potential to migrate to ground water. Because they do not evaporate, nitrates and nitrites are likely to remain in water until consumed by plants or other organisms. Primary sources of nitrate which may contaminate drinking water are human sewage, livestock manure, and fertilizers.

In 2007, there were 562 public water systems, serving 257, 558 people, reporting violations of the nitrate MCL.[1314] If a utility's routine compliance monitoring indicates that nitrate or nitrite concentrations are above the MCL, the water system must implement measures such as treatment or blending to reduce the concentration so that it is below the MCL (e.g., find a new source of water, adjust existing treatment or install new treatment). Also, utilities must monitor the finished water every quarter and provide notification to consumers of the MCL exceedance.

Since there is no nationally consistent sampling of ambient water used by public water systems, the relative contribution of nitrate detections from the various sources is generally unknown.

### 6.9.2 Pesticides

The U.S. Geological Survey evaluated the fate and transport of herbicides in surface water, ground water, and in precipitation in the Midwest during the 1990s. Results of these studies showed the occurrence and temporal distribution of herbicides and their associated degradation products in reservoir outflows.[1315]

Atrazine is estimated to be the most widely used herbicide in the United States for control of weeds. Atrazine was the second most frequently detected pesticide in EPA's National Survey of Pesticides in Drinking Water Wells. EPA's Pesticides in Ground Water Database indicates numerous detections of atrazine at concentrations above the MCL in ground water in several states, including Delaware, Illinois, Indiana, Iowa, Kansas, Michigan, Minnesota, Missouri, Nebraska, and New York.[1316] In 1993, EPA and the atrazine registrants initiated a monitoring program to focus on the most significant exposures associated with agricultural and residential uses -- exposures through drinking water. To this point, levels found in PWS have been low. Through the PWS monitoring program, EPA is ensuring that exposures to atrazine in drinking water do not reach levels that pose a risk to public health.

The MCL for atrazine is three parts per billion (ppb). MCL violations are not triggered by single measurement above the MCL but by the running annual average concentration from four quarterly samples in which at least one measurement during that period exceeds 3 ppb. Some people who drink water containing atrazine well in excess of the MCL over a period of many years could experience problems with their cardiovascular system or reproductive difficulties. This health effects language is not intended to catalog all possible health effects for atrazine. Rather, it is intended to inform people of the most significant and probable health effects, associated with atrazine in drinking water.

Atrazine may be released to the environment in wastewater from herbicide manufacturing facilities and through its use as an herbicide. Microbial activity and other chemicals may breakdown atrazine in soil and water, particularly in alkaline conditions. Sunlight and evaporation do not reduce its presence. It may bind to some soils, but generally tends to leach to ground water. Atrazine is not likely to be taken up in the tissues of plants or animals.[1317]

In *A Review of Contaminant Occurrence in Public Water Systems*, published in 1999, EPA found atrazine in the finished water of 21% of the surface water systems.[1318] Atrazine was found at concentrations exceeding the MCL in 10.7% of the surface water systems and, in 83% of those systems, atrazine was found at concentrations that would have been in violation of the MCL. As noted above, MCL violations are not triggered by single excursions above the MCL but by the running annual average concentration from four quarterly samples in which the measurement of at least one of those samples exceeds three ppb. However in one of the states where atrazine is widely used e.g., for corn production, the percentage of single samples exceeding the MCL was as high as 77.8% for surface water systems serving less than 500 people; see Table 6.1.

**Table 6.9-1.**
**Percentage of Surface Water Systems with Detections of Atrazine for a High Occurrence State, 1999**

| POPULATION | <500 | 500 – 3,300 | 3,301 – 10,000 | 10,001 – 50,000 | > 50,000 |
|---|---|---|---|---|---|
| > MRL[a] | 100% | 100% | 96.2% | 96.3% | 55.6% |
| > MCL[b] | 77.8% | 71.1% | 57.7% | 18.5% | 22.2% |

[a] The MRL, or minimum reporting level, is the lowest concentration at which the contaminant can be consistently and reliably detected. U.S. Environmental Protection Agency, *A Review of Contaminant Occurrence in Public Water Systems*, EPA 816-R-99-006, 1999, Table V.A.2, page D-2.

[b] U.S. Environmental Protection Agency, ibid, p. D-3.

In 2003, EPA estimated that single atrazine measurements greater than the MCL would be observed in 26 to 57 public water systems serving a range of 24,400 – 260,300 people.[1319]

Because atrazine is used mostly as a pre-emergent herbicide on corn, the surface water concentrations typically spike during growing season then taper off for the rest of the year. Even though many surface water systems encounter concentrations above the MCL during the growing season, very few experience MCL violations based on the average concentration over four consecutive quarters. In 2007, only one water system serving 740 people officially reported a MCL violation.[1320]

From 1992 through 2001, the USGS observed atrazine in 90% of the samples it took from 83 stream sites in agricultural areas as part of its National Water Quality Assessment (NAWQA). Although it does not target exclusively drinking water intakes or wells, the NAWQA program "provides an understanding of water-quality conditions and how those conditions may vary locally, regionally, and nationally**…".**[1321] Atrazine was observed in 71% of the samples from 30 urban stream sites during the same period. For ground water, USGS observed atrazine in 42% of the samples it took from wells in agricultural areas and in 31% of the samples from urban wells. The detection limits for this study were very low and 95% of the sampling results from streams in agricultural areas, where the highest concentrations of atrazine were found, were below 2.4 ppb which is 80% of the MCL of 3 ppb.

### 6.9.3 Future availability of more recent occurrence data

EPA anticipates releasing the chemical occurrence data covering the years 1999 – 2006 from states for publication in 2010 as part of the six year review of drinking water standards. Once those data sets are publicly available, they will be useful in updating the occurrence data published here for nitrate and atrazine.

## 6.10 Water Quantity Concerns

Biofuel production based on current and projected approaches and processes, future alternative fuel development and production could markedly increase the demand for various fresh water resources. Two potential needs could increase water demand: quantities of water to produce biomass as a feedstock, and the additional water demand for refining of bio-ethanol and biodiesel fuels (by up to a factor of three relative to traditional refining). From a regional perspective, water demand for crop production would be relatively much larger than biorefinery demand; crop production needs would be approximately 200 times the water needed to refine biofuels.[1322]

With growth of ethanol production, water supply reliability related to crop demand for biomass feedstock will remain an issue. The amount of water needed to grow feedstocks for biofuels can be considerable – for example, the ratio of water consumed to produce the corn itself for ethanol is nearly one thousand gallons per gallon of corn ethanol. Large scale production of perennial energy crops involving tens of millions of acres, even when rain-fed, can have water resource impacts and unintended local consequences due to alterations of hydrologic flows. The timing of the water demand may also be critical; water is often plentiful in one season but scarce in another.

Growing crops for biofuel production is likely to have significant regional and local impacts, including the potential to change irrigation water use, and thus local water availability. The feasibility and sustainability of water diversions for biomass irrigation will vary depending on the region. Moreover, some ethanol plants are being sited where water resources are already under duress, for example on the High Plains aquifer.

Biofuel refineries create additional local scale demand for water withdrawals and consumption. It is difficult to generalize about the impact on local water supplies, however, some community supplies have been stressed by the water requirements of ethanol facilities. However, from a national and regional perspective, relative to the water incorporated in the feedstock, water use in biorefineries is quite small. A typical corn ethanol plant consumes slightly more than four gallons water per gallon of ethanol produced; biodiesel refining even less, about one gallon of water per gallon of biodiesel, which on an energy-equivalent basis is even less in comparison to ethanol. (Petroleum refining consumes about 1.5 gallons of water per gallon fuel produced.) Biodiesel refining consumes about one gallon water per gallon, but may be up to three gallons per gallon. However, biofuel crops may be irrigated with wastewater that is biologically and chemically unsuitable for use with food crops. On the other hand, cellulosic materials require a different process, and are thought to use 9.5 gallons water per gallon fuel produced--but this would be expected to decline as efficiency increases (currently projected to be lowered to two to six gallons per gallon).

Geographic impacts of biofuel refining vary. Currently, the Midwest and Southeast have most of the production. In Iowa, water consumption alone from ethanol refining already accounts for about 7% of all industrial water use, and is projected to be 14% by 2012--or about 50 million gallons per day. A typical ethanol plant now producing 50 million gallons per year means a minimum of 175 million gallons (nearly 480,000 per day) used in a year. In the Great Lakes-St. Lawrence region, newer facilities under construction will have capacities of 100 million gallons per year.[1323] For a 100 million gallon per year corn ethanol plant, water consumption is one million gallons of water/day (equates to daily water consumption of a town of 20,000).

Research is needed to establish water use requirements across the entire biofuel production chain. Information needs related to biomass feedstock production include the assessment and quantification of impacts of increased irrigation of energy crops and resulting biofuel cost/benefit tradeoffs for both starch/sugar/oil biofuel crops, and the lignocellulosic biofuel crops. An assessment is also needed of the impacts on hydrologic flows of regional expansion of perennial energy crop production. These include the impacts and risks tradeoffs, e.g., altered flows due to deep extensive root systems and dense canopies, as well as a need for management practices/metrics, e.g. relatively large absolute water consumption, and additional irrigation necessary. Changing climate adds an additional element of uncertainty in making assessments of water use.

Many uncertainties exist regarding estimating water needs for irrigating cellulosic feedstocks in particular. Reasons include: water data is less available for proposed cellulosic feedstock than for common crops, evapotranspiration rates of marginal lands used for these crops are unknown, and water demand by heretofore unirrigated native grasses is unknown.

Some practices can mitigate the increased demand for water by biofuels. Both the impacts and regulatory opportunities for mitigation of water impacts are likely to be at the state and local levels. For example, rainfall harvesting, efficient irrigation water transport and use of reclaimed water can lead to more efficient agricultural water use for both corn and cellulosic ethanol crops. Also, biorefineries are increasingly incorporating water recycling.

The economics of the energy-water distribution linkage are important in biofuels production. At a macroscale, the high prices of energy driving the increased production of biofuels will likely affect water availability and use, e.g., conveyance costs related to irrigation waters will also increase with energy costs, possibly leading to water conservation that may counter the expanded water use for crops. Also, the value of crops relative to their water demand matters: water rights can often be bought and sold if the value of the crop is sufficiently high.

Finally, there is the potential for a low water use alternative biomass feedstock to develop: oil-producing macro-algae. These algae can be grown without land, using nontraditional waters, and CO2 waste streams as a nutrient source. Such fuels can have significantly higher energy density and are potentially more fungible within existing transportation fuel infrastructure than ethanol.

# Chapter 7: Final Regulatory Flexibility Analysis

This chapter discusses our Final Regulatory Flexibility Analysis (FRFA) which evaluates the potential impacts of the standards on small entities. The Regulatory Flexibility Act, as amended by the Small Business Regulatory Enforcement Fairness Act of 1996 (SBREFA), generally requires an agency to prepare a regulatory flexibility analysis of any rule subject to notice and comment rulemaking requirements under the Administrative Procedure Act or any other statute unless the agency certifies that the rule will not have a significant economic impact on a substantial number of small entities. Prior to issuing a proposal for this rulemaking, we analyzed the potential impacts of these regulations on small entities. As a part of this analysis, we convened a Small Business Advocacy Review Panel (SBAR Panel, or 'the Panel'). During the Panel process, we gathered information and recommendations from Small Entity Representatives (SERs) on how to reduce the impact of the rule on small entities, and those comments are detailed in the Final Panel Report which is located in the public record for this rulemaking (Docket EPA-HQ-OAR-2005-0161).

## 7.1 Overview of the Regulatory Flexibility Act

In accordance with section 609(b) of the Regulatory Flexibility Act, we convened an SBAR Panel before conducting the FRFA. A summary of the Panel's recommendations can be found in the preamble to the proposed rule. Further, the Final Panel Report contains a detailed discussion of the Panel's advice and recommendations (as well as comments from the Small Entity Representatives (SERs)). The regulatory alternatives that are being adopted in this final rule are described below.

Section 609(b) of the Regulatory Flexibility Act further directs the Panel to report on the comments of small entity representatives and make findings on issues related to identified elements of the Regulatory Flexibility Analysis under section 603 of the Regulatory Flexibility Act. Key elements of a Regulatory Flexibility Analysis are:

- a description of and, where feasible, an estimate of the number of small entities to which the rule will apply;
- projected reporting, record keeping, and other compliance requirements of the rule, including an estimate of the classes of small entities which will be subject to the requirements and the type of professional skills necessary for preparation of the report or record;
- an identification, to the extent practicable, of all other relevant Federal rules which may duplicate, overlap, or conflict with the rule;
- any significant alternatives to the rule which accomplish the stated objectives of applicable statutes and which minimize any significant economic impact of the rule on small entities.

The Regulatory Flexibility Act was amended by SBREFA to ensure that concerns regarding small entities are adequately considered during the development of new regulations that affect those entities. Although we are not required by the Clean Air Act to provide special treatment to small businesses, the Regulatory Flexibility Act requires us to carefully consider the economic impacts that our rules may have on small entities. The recommendations made by the Panel may serve to help lessen these economic impacts on small entities when consistent with Clean Air Act requirements.

## 7.2 Need for the Rulemaking and Rulemaking Objectives

A detailed discussion on the need for and objectives of this rule are located in the preamble to the final rule. As previously stated, section 1501 of the Energy Policy Act of 2005 (EPAct) amended section 211 of the Clean Air Act (CAA) by adding section 211(o) which required the Environmental Protection Agency (EPA) to promulgate regulations implementing a renewable fuel program. The final Renewable Fuels Standard (RFS1) program, which began on September 1, 2007, created a specific annual level for minimum renewable fuel use that increases over time — resulting in a requirement that 7.5 billion gallons of renewable fuel be blended into gasoline by 2012.

The Energy Independence and Security Act of 2007 (EISA) amended section 211(o), and the RFS program, by requiring higher volumes of renewable fuels, to result in 36 billion gallons of renewable fuel by 2022. EISA also expanded the purview of the RFS1 program by requiring that these renewable fuels be blended into diesel fuel (both highway and nonroad) in addition to gasoline. This expanded the volume obligation of parties that were already regulated under RFS1. It also expanded the pool of regulated entities, so the obligated parties under the RFS2 rule will now include certain refiners, importers, and blenders of these fuels that were not previously covered by the RFS1 program. In addition to the total renewable fuel standard required by EPAct, EISA added standards for three additional types of renewable fuels to the program (advanced biofuel, cellulosic biofuel, and biomass-based diesel) and requires compliance with all four standards.

## 7.3 Definition and Description of Small Entities

Small entities include small businesses, small organizations, and small governmental jurisdictions. For the purposes of assessing the impacts of the rule on small entities, a small entity is defined as: (1) a small business that meets the definition for business based on the Small Business Administration’s (SBA) size standards; (2) a small governmental jurisdiction that is a government of a city, county, town, school district or special district with a population of less than 50,000; and (3) a small organization that is any not-for-profit enterprise which is independently owned and operated and is not dominant in its field.

Small businesses (as well as large businesses) would be regulated by this rulemaking, but not small governmental jurisdictions or small organizations as described above. As set by SBA, the categories of small entities that will potentially be affected by this rulemaking are defined in Table 7.3-1 provides an overview of the primary SBA small business categories potentially affected by this regulation.

**Table 7.3-1. Small Business Definitions**

| Industry | Defined as small entity by SBA if less than or equal to: | NAICS[a] codes |
|---|---|---|
| Gasoline and diesel fuel refiners | 1,500 employees[b] | 324110 |

[a] *North American Industrial Classification System*

[b] *EPA has included in past fuels rulemakings a provision that, in order to qualify for the small refiner flexibilities, a refiner must also produce no greater than 155,000 bpcd crude capacity*

EPA used a variety of sources to identify which entities are appropriately considered "small." EPA used the criteria for small entities developed by the Small Business Administration under the North American Industry Classification System (NAICS) as a guide. Information about the characteristics of refiners comes from sources including the Energy Information Administration (EIA) within the U.S. Department of Energy, oil industry literature, and previous rulemakings that have affected the refining industry. EPA then found employment information for these companies using the business information database Hoover's Online (a subsidiary of Dun and Bradstreet). These refiners fall under the Petroleum Refineries category, 324110, as defined by NAICS.

Small entities that will be subject to the renewable fuel standard include: domestic refiners that produce gasoline and/or diesel, and importers of gasoline and/or diesel into the U.S. Based on 2007 data, EPA believes that there are about 95 refiners of gasoline and diesel fuel. Of these, EPA believes that there are currently 17 refiners owning 20 refineries producing gasoline and/or diesel fuel that meet the SBA small entity definition of having 1,500 employees or less. Further, we believe that three of these refiners own refineries that do not meet the definition of a "small refinery" that Congress specified under section 211(o). It should be noted that because of the dynamics in the refining industry (i.e., mergers and acquisitions), the actual number of refiners that ultimately qualify for small refiner status under the RFS2 program could be different from this initial estimate.

## 7.4 Steps to Minimize Impacts on Small Entities

As a part of the SBREFA process, we conducted outreach to small refiners of gasoline and/or diesel fuels and convened a Panel to gain feedback and advice from these entities. Prior to convening the Panel, we held outreach meetings with the SERs to learn the needs of small entities and potential challenges that these entities may face. The outreach meetings also helped to provide the SERs an opportunity to gain a better understanding of the new requirements under EISA and how it would change the RFS program (including those small refiners who only produce diesel and were not regulated entities ). The feedback that we received from SERs as a result of these meetings was used during the Panel process to develop regulatory alternatives to mitigate the impacts of the rulemaking on small businesses. General concerns raised by SERs during the SBREFA process were potential costs and access to RINs for compliance with the program.

The Panel consisted of members from EPA, the Office of Management and Budget (OMB), and the Small Business Administration's Office of Advocacy. Following the Panel convening, a Final Panel Report detailing all of the alternatives that were recommended by the Final Regulatory Support Document Panel (as well as individual Panel members) was issued. We either proposed or requested comment on the various recommendations put forth by the Panel. Below we discuss those flexibility options recommended in the Panel Report, our proposed regulatory alternatives, and those provisions which are being finalized.

### 7.4.1 Panel Recommendations

The purpose of the Panel process is to solicit information as well as suggested flexibility options from the SERs, and the Panel recommended that EPA continue to do so during the development of the RFS2 rule. Recognizing the concerns about EPA's authority to provide extensions to a subset of small refineries (i.e., those that are owned by small refiners) different from that provided to small refineries in section 211(o)(9), the Panel recommended that EPA continue to evaluate this issue, and that EPA request comment on its authority and the appropriateness of providing extensions beyond those authorized by section 211(o)(9) for small refineries operated by a small refiner. The Panel also recommended that EPA propose to provide the same extension provision of 211(o)(9) to small refiners who do not own small refineries as is provided for small refiners who do own small refineries.

### 7.4.2 Extensions of the Temporary Exemption Based on a Study of Small Refinery Impacts

Panel Recommendations

The Panel recommended that EPA propose in the RFS2 program the provision at 40 CFR 80.1141(e) extending the RFS1 temporary exemption for at least two years for any small refinery that DOE determines would be subject to disproportionate economic hardship if required to comply with the RFS2 requirements.

Section 211(o)(9)(A)(ii) requires DOE to perform a study of the economic impacts of the RFS requirements on small refineries. The study, which was required to be completed by December 31, 2008, must assess and determine whether the RFS requirements would impose a disproportionate economic hardship on small refineries. Small refineries that are found to be in a disproportionate economic hardship situation will receive an extension of the temporary exemption for at least two years.

The Panel also recommended that EPA work with DOE in the development of the small refinery study, specifically to communicate the comments that SERs raised during the Panel process.

What We Proposed and Public Comments Received on the NPRM

We did not propose this hardship provision given the outcome of the DOE small refinery study. In the small refinery study, "EPACT 2005 Section 1501 Small Refineries Exemption

Study", DOE's finding was that there is no reason to believe that any small refinery would be disproportionately harmed by inclusion in the proposed RFS2 program. This finding was based on the fact that there appeared to be no shortage of RINs available under RFS1, and EISA has provided flexibility through waiver authority (per section 211(o)(7)). Further, in the case of the cellulosic biofuel standard, cellulosic biofuel allowances can be provided from EPA at prices established in EISA (see regulation section 80.1455). DOE thus determined that no small refinery would be subject to disproportionate economic hardship under the proposed RFS2 program, and that the small refinery exemption should not be extended beyond December 31, 2010. DOE noted in the study that, if circumstances were to change and/or the RIN market were to become non-competitive or illiquid, individual small refineries have the ability to petition EPA for an extension of their small refinery exemption (as stated in regulation section 80.1441).

In their written comments, as well as in discussions we had with them on the proposed rule, small refiners indicated that they did not believe that EPA should rely on the results of the DOE small refinery study to inform any decisions on small refiner provisions. Small refiners generally commented that they believe that the study was flawed and that the conclusions of the study were reached without adequate analysis of, or outreach with, small refineries (as the majority of the small refiners own refineries that meet the Congressional small refinery definition). One commenter stated that such a limited investigation into the impact on small refineries could not have resulted in any in-depth analysis on the economic impacts of the program on these entities. Another commenter stated that it believes that DOE should be directed to reopen and reassess the small refinery study be June 30, 2010, as suggested by the Senate Appropriations Committee.

What We're Finalizing

As discussed more in section III.E of the preamble to the final rule, since the only small refinery study available for us to use as a basis for whether or not to grant small refineries an automatic two-year extension of the exemption is the study that was performed in 2008, we had to use this study to develop this final rule. EPAct directs EPA to consider the DOE small refinery study in assessing the impacts to small refineries, and we interpret this to mean that any extension past December 31, 2010 has to be tied to the DOE Study. Further, since that study found that there was no disproportionate economic impact on small refineries, we cannot grant an automatic additional extension for small refineries or small refiners (except on a case-by-case hardship basis). However, this does not preclude small refiners from applying for case-by-case extensions of the small refiner temporary exemption.

We are aware that there have been expressions of concern from Congress regarding the DOE Study. Specifically, in Senate Report 111-45, the Senate Appropriations Committee "directed [DOE] to reopen and reassess the Small Refineries Exemption Study by June 30, 2010," noting a number of factors that the Committee intended that DOE consider in the revised study. The Final Conference Report 111-278 to the Energy & Water Development Appropriations Act (H.R. 3183), referenced the language in the Senate Report, noting that the conferees "support the study requested by the Senate on RFS and expect the Department to undertake the requested economic review." The DOE study has not been revised at this time; however, if DOE prepares a revised study and the revised study finds that there is a disproportionate economic impact, we will revisit the exemption extension at that point in accordance with section 211(o)(9)(A)(ii).

### 7.4.3 Delay in Standards for Small Refiners

Panel Recommendations

The RFS1 program regulations provide small refiners who operate small refineries as well as small refiners who do not operate small refineries with a temporary exemption from the standard through December 31, 2010. Small refiner SERs suggested that an additional temporary exemption for the RFS2 program would be beneficial to them in meeting the RFS2 standards. EPA evaluated a temporary exemption for at least some of the four required RFS2 standards for small refiners. The Panel recommended that EPA propose a delay in the effective date of the standards until 2014 for small entities, to the maximum extent allowed by the statute. However, the Panel recognized that EPA has serious concerns about its authority to provide an extension of the temporary exemption for small refineries that is different from that provided in CAA section 211(o)(9), since Congress specifically addressed an extension for small refineries in that provision.

The Panel did recommend that EPA propose other avenues through which small refineries and small refiners could receive extensions of the temporary exemption. These avenues were a possible extension of the temporary exemption for an additional two years following a study of small refineries by the Department of Energy (DOE) (as discussed above) and provisions for case-by-case economic hardship relief.

What We Proposed and Public Comments Received on the NPRM

We proposed and took comment on the recommendations of the Panel and SERs. We proposed to continue the temporary exemption finalized in RFS1, through December 31, 2010, for small refiners (and small refineries), extending it to include an exemption for diesel volume and diesel refiners, importers, and blenders, as required by EISA.

Commenters that oppose an extension of the temporary exemption generally stated that they believe an extension is not warranted, and some of these commenters expressed concerns about allowing provisions for small refiners. One commenter also stated that the small refinery exemption should not be extended and that the small refiner exemption should be eliminated completely. A couple commenters supported the continuation of the exemption through December 31, 2010 only; one of those commenters stated that it does not support an extension as it believes that all parties have been well aware of the passage of EISA and small refineries and small refiners should have been striving to achieve compliance by the end of 2010. Two commenters also expressed views that the exemption should not have been offered to small refiners in RFS1 as this was not provided by EPAct, and that an extension of the exemption should not be finalized for small refineries at all. The commenters further commented that an economic hardship provision was included in EPAct, and any exemption extension should be limited to such cases, and only to the specific small refinery (not small refiner) that has petitioned for such an extension.

Commenters supporting an extension of the exemption commented that they believe that the statutes (EPAct and EISA) do not prohibit EPA from providing relief to regulated small entities on which the rule will have a significant economic impact, and that such a delay could lessen the burden on these entities. One commenter stated that it believes EPA denied or ignored much of the relief recommended by the Panel in the proposal. Another commenter stated that it believes EPA's concerns regarding the legal authority are unsustainable considering EPA's past exercises of discretion under the RFS1 program, and with the discretion afforded to EPA under section 211(o) of the CAA. Some commenters requested a delay until 2014 for small refiners. One additional commenter expressed support for an extension of the small refinery exemption only, and stated that these small refineries should be granted a permanent exemption.

What We're Finalizing

The RFS1 program regulations exempt gasoline produced by small refineries from the renewable fuels standard through December 31, 2010 (at 40 CFR 80.1141), per EPAct. As EISA did not alter the small refinery exemption in any way, we are retaining this small refinery temporary exemption in the RFS2 program, extending the relief to diesel fuel volumes produced or imported in addition to gasoline, and extending the relief to those small refineries of diesel fuel that were not covered under RFS1. Likewise, as we extended under RFS1 the small refinery temporary exemption to the few remaining small refiners that met the Small Business Administration's (SBA) definition of a small business (1,500 employees or less company-wide), we are also finalizing a continuation of the small refiner temporary exemption through December 31, 2010 for all gasoline and diesel small refiners.

As described in the Final Panel Report, EPA early-on identified limitations on its authority to issue additional flexibility and exemptions to small refineries. In section 211(o)(9) Congress specifically addressed the issue of an extension of time for compliance for small refineries, temporarily exempting them from renewable fuel obligations through December 31, 2010. As discussed above, the statute also includes two specific provisions describing the basis and manner in which further extensions of this exemption can be provided. In the RFS1 rulemaking, EPA considered whether it should provide additional relief to the limited number of small refiners who were not covered by the small refinery provision, by providing them a temporary exemption consistent with that provided by Congress for small refineries. EPA exercised its discretion under section 211(o)(3) and provided such relief. Thus, in RFS1, EPA did not modify the relief provided by Congress for small refineries, but did exercise its discretion to provide the same relief specified by statute to a few additional parties.

In RFS2 we are faced with a different issue—the extent to which EPA should provide additional relief to small refineries beyond the relief specified by statute, and whether it should provide such further relief to small refiners as well. There is considerable overlap between entities that are small refineries and those that are small refiners. Providing additional relief just to small refiners would, therefore, also extend additional relief to at least a number of small refineries. Congress spoke directly to the relief that EPA may provide for small refineries, including those small refineries operated by small refiners, and limited that relief to a blanket exemption through December 31, 2010, with additional extensions if the criteria specified by

Congress are met. EPA believes that an additional or different extension, relying on a more general provision in section 211(o)(3) would be inconsistent with Congressional intent. Further, we do not believe that the statute allows us the discretion to give relief to small refiners only—as this would result in a subset of small refineries (those that also qualify as small refiners) receiving relief that is greater than the relief already given to all small refineries under EISA.

EPA also notes that the criteria specified by statute for providing a further compliance extension to small refineries is a demonstration of "disproportionate economic hardship." The statute provides that such hardship can be identified through the DOE study, or in individual petitions submitted to the Agency. However, the DOE study has concluded that no disproportionate economic hardship exists, at least under current conditions and for the foreseeable future under RFS2. Therefore, absent further information that may be provided through the petition process, there does not currently appear to be a basis under the statute for granting further compliance extensions to small refineries. If DOE revises its study and comes to a different conclusion, EPA can revisit this issue.

During the development of this final rule, we again evaluated the various options recommended by the Panel, the legality of offering an extension of the exemption to small refiners only, and also comments on the proposed rule. Specifically in the case of an extension of the exemption for small refiners, we also consulted the small refinery study prepared by DOE, as the statute directs us to use this as a basis for providing an additional two year exemption. As discussed in Section III.E of the preamble to the final rule, we do not believe that we can provide an extension of the exemption considering the outcome of the DOE small refinery study, which did not find that there was a disproportionate economic hardship. Further, we do not believe that the statute allows us the discretion to give relief to a subset of small refineries (those that also qualify as small refiners) that is greater than the relief already given to all small refineries under EPAct. However, it is important to recognize that the 211(o)(9) small refinery provision does allow for extensions beyond December 31, 2010, as discussed in preamble Section III.E.2. Thus, refiners may apply for individual hardship relief.

### 7.4.4 Phase-in

<u>Panel Recommendations</u>

Small refiner SERs suggested that a phase-in of the obligations applicable to small refiners would be beneficial for compliance, such that small refiners would comply by gradually meeting the standards on an incremental basis over a period of time, after which point they would comply fully with the RFS2 standards, EPA has serious concerns about its authority to allow for such a phase-in of the standards. CAA section 211(o)(3)(B) states that the renewable fuel obligation shall "consist of a single applicable percentage that applies to all categories of persons specified" as obligated parties. This kind of phase-in approach would result in different applicable percentages being applied to different obligated parties. Further, such a phase-in approach would provide more relief to small refineries operated by small refiners than that provided under the small refinery provision. Thus the Panel recommended that EPA should invite comment on a phase-in, but not propose such a provision.

What We Proposed and Public Comments Received on the NPRM

While we did not propose it, we did request comment on the concept of a phase-in for small refiners only. Specifically, we requested comments on a phase-in for some or all of the applicable standards for small refiners.

With respect to our request for comments on the concept of a phase-in of the RFS standards for small refiners, some commenters stated that they believe that EPA has the ability to consider a phase-in of the standards for small refiners. One commenter suggested that a temporary phase-in could help lessen the burden of regulation on small entities and promote compliance. Another commenter stated that it believes EPA's legal concerns regarding a phase-in are unsustainable considering EPA's past exercises of discretion under the RFS1 program and with the discretion afforded to EPA under section 211(o) of the CAA.

What We're Finalizing

After considering the comments on this issue, EPA continues to believe that allowing a phase-in of regulatory requirements for small refineries and/or small refiners would be inconsistent with the statute, for the reasons mentioned above. Any individual entities that are experiencing hardship that could justify a phase-in of the standards have the ability to petition EPA for individualized relief. Therefore we are not including a phase-in of standards for small refiners in the final rule.

### 7.4.5 RIN-related Flexibilities

Panel Recommendations

The small refiner SERs requested that the proposed rule contain provisions for small refiners related to the RIN system, such as flexibilities in the RIN rollover cap percentage and allowing all small refiners to use RINs interchangeably. In the RFS1 program, EPA allows for 20% of a previous year's RINs to be "rolled over" and used for compliance in the following year. We noted during the Panel process that a provision to allow for flexibilities in the rollover cap could include a higher RIN rollover cap for small refiners for some period of time or for at least some of the four standards. Further, we noted our belief that since the concept of a rollover cap was not mandated by section 211(o), EPA believes that there may be an opportunity to provide appropriate flexibility in this area to small refiners under the RFS2 program but only if it is determined in the DOE small refinery study that there is a disproportionate effect warranting relief. The Panel recommended that EPA request comment on increasing the RIN rollover cap percentage for small refiners, and further that EPA should request comment on an appropriate level of that percentage. The Panel also recommended that EPA invite comment on allowing RINs to be used interchangeably for small refiners, but not propose this concept because under this approach small refiners would arguably be subject to a different applicable percentage than other obligated parties.

What We Proposed and Public Comments Received on the NPRM

We proposed a change to the RIN rollover cap for small refiners only, and we requested comment on appropriate level to set the rollover cap for these entities. We also took comment on the concept of allowing RINs to be used interchangeably for small refiners only.

We also requested comment on the concept of RIN-related flexibilities for small refiners. In their comments on the proposed rule, one small refiner commented that, in regards to small refiners' concerns about RIN pricing and availability, there is no mechanism in the rule to address the possibility that the RIN market will not be viable. The commenter further suggested that more "durable" RINs are needed for small refiners that can be carried over from year to year, to alleviate some of the potentially market volatility for renewable fuels. Another commenter suggested that RINs should be interchangeable for small refiners, or alternatively, some mechanism should be implemented to ensure that RIN prices are affordable for small refiners. Further, with regard to interchangeable RINs, one commenter stated that small refiners do not have the staff or systems to manage and account for four different categories of RINs and rural small refiners will suffer economic hardship and disadvantage because of the unavailability of biofuels. The commenter also requested an increase in the rollover cap to 50% for small refiners.

What We're Finalizing

We are not finalizing RIN-related provisions in today's action. As highlighted in the NPRM, we continue to believe that the concept of interchangeable RINs for small refiners only fails to require the four different standards mandated by Congress (e.g., conventional biofuel could not be used instead of cellulosic biofuel or biomass-based diesel). Further, given the findings from the DOE study, if small refineries and small refiners do not face disproportionate economic hardship, then we do not believe that we have the basis for granting such additional relief beyond what Congress already provided. Thus, small refiners will be held to the same RIN rollover cap as other obligated parties.

### 7.4.6 Program Review

Panel Recommendations

During the SBREFA process, SERs raised concerns over uncertainty with acquiring RINs, and the potential pricing of RINs. They commented that an annual program review would be beneficial to small refiners as it could provide information about the RIN system. EPA raised the concern that this could lead to some redundancy since EPA is required to publish a notice of the applicable RFS standards in the Federal Register annually, and that this annual process will inevitably include an evaluation of the projected availability of renewable fuels. Nevertheless, the SBA and OMB Panel members stated that they believe that a program review could be helpful to small entities in providing them some insight to the RFS program's progress and alleviate some uncertainty regarding the RIN system. As EPA will be publishing a Federal Register notice annually, the Panel recommended that EPA include an update of RIN system progress (e.g., RIN trading, RIN availability, etc.) in this notice and that the results of this evaluation be considered in any request for case-by-case hardship relief.

What We Proposed and Public Comments Received on the NPRM

In the NPRM, we proposed that we would include information to help inform industry about the RIN system in the annual notice of the RFS standards that EPA must publish in the Federal Register. We also proposed that information from the annual Production Outlook Reports that producers and importers must submit to EPA, as well as information required in EMTS reports, could be used in the annual Federal Register notice to update RIN system progress.

A group of commenters stated that they support the concept of an annual review. They commented that EPA should include a review of the RIN system in annual review procedures, and further suggested that EPA invite small refiner participation in the development of the review process. (For more information on the comments received on Production Outlook Reports specifically, please see Chapter 3 of the Summary and Analysis of Comments.)

What We're Finalizing

Based on comments received on the proposed rule, we believe that such information could be helpful to industry, especially to small businesses to help aid the proper functioning of the RIN market, especially in the first years of the program. However, during the development of the final rule, it became evident that there could be instances where we would want to report out RIN system information on a more frequent basis than just once a year. Thus, we are finalizing that we will report out elements of RIN system progress; but such information will be reported via other means (e.g., the RFS website (www.epa.gov/otaq/renewablefuels/index.htm), EMTS homepage, etc.). Additionally, we will also publish annual summaries of the Production Outlook Reports.

### 7.4.7 Extensions of the Temporary Exemption Based on Disproportionate Economic Hardship

Panel Recommendations

While SERs did not specifically comment on the concept of hardship provisions for the upcoming proposal, the Panel noted that under CAA section 211(o)(9)(B) small refineries may petition EPA for case-by-case extensions of the small refinery temporary exemption on the basis of disproportionate economic hardship. Refiners may petition EPA for this case-by-case hardship relief at any time.

The Panel recommended that EPA propose in the RFS2 program a case-by-case hardship provision for small refineries similar to that provided at 40 CFR 80.1141(e)(1). The Panel also recommended that EPA propose a case-by-case hardship provision for small refiners that do not operate small refineries that is comparable to that provided for small refineries under section 211(o)(9)(B), using its discretion under CAA section 211(o)(3)(B). This would apply if EPA does not adopt an automatic extension for small refiners, and would allow those small refiners that do not operate small refineries to apply for the same kind of extension as a small refinery. The Panel recommended that EPA take into consideration the results of the annual update of RIN system progress and the DOE small refinery study in assessing such hardship applications.

What We Proposed and Public Comments Received on the NPRM

We did propose hardship provisions for small refineries and small refiners in the RFS2 proposal program similar to those provided at 40 CFR 80.1141 and 80.1142. We propose to extend the temporary exemption for at least two years for any small refinery that DOE's small refinery study determines would face disproportionate economic hardship in meeting the requirements of the RFS2 program (per CAA section 211(o)(9)(A)(ii)(I)), and that any small refinery could apply for a case-by-case hardship at any time on the basis of disproportionate economic hardship per section 211(o)(9)(B). For those small refiners that do not operate small refineries, we also proposed the same case-by-case hardship provision using our discretion under CAA section 211(o)(3)(B).

While the findings from DOE's small refinery study indicate that no small refineries would be subject to disproportionate economic hardship under the proposed RFS2 program and that the small refinery exemption should not be extended beyond December 31, 2010, DOE noted in the study that if circumstances were to change and/or the RIN market became non-competitive or illiquid, individual small refineries have the ability to petition EPA for an extension of their small refinery exemption.

Two commenters noted that an economic hardship provision was included in EPAct, and commented that any extension of the exemption past 2010 should be limited to such cases, and only to the specific small refinery (not small refiner) that has petitioned for such an extension. A group of commenters also stated that they believe that small refiners that may be subject to disproportionate hardship should be granted a two-year extension of the existing RFS1 temporary exemption. The commenters further suggested that EPA tailor the case-by-case hardship provisions to include a general hardship exemption of up to five years for any and all small refiners meeting certain specified hardship criteria. The commenters stated that such criteria should be developed with small refiner participation.

What We're Finalizing

We believe that these avenues of relief can and should be fully explored by small refiners who are covered by the small refinery provision. In addition, we believe that it is appropriate to allow petitions to EPA for an extension of the temporary exemption based on disproportionate economic hardship for those small refiners who are not covered by the small refinery provision (again, per our discretion under section 211(o)(3)(B)); this would ensure that all small refiners have the same relief available to them as small refineries do. Thus, we are finalizing a hardship provision for small refineries in the RFS2 program, that any small refinery may apply for a case-by-case hardship at any time on the basis of disproportionate economic hardship per CAA section 211(o)(9)(B). We are also finalizing a case-by-case hardship provision for those small refiners that do not operate small refineries (section 80.1442(h)) using our discretion under CAA section 211(o)(3)(B). This provision will allow those small refiners that do not operate small refineries to apply for the same kind of extension as a small refinery. In evaluating applications for this hardship provision EPA will take into consideration information gathered from annual reports and RIN system progress updates, as recommended by the SBAR Panel.

## 7.5 Reporting, Recordkeeping, and Other Compliance Requirements

Registration, reporting, and recordkeeping are necessary to track compliance with the RFS standards and transactions involving RINs. As discussed in Sections II.J and III.A of the preamble to the final rule, the compliance requirements under the RFS2 rule are in many ways similar to those required under the RFS1 rule, with some modifications (e.g., those to account for the new requirements of EISA). New provisions being finalized in today's action include the new EPA Moderated Transaction System (EMTS) to aid industry in their reporting and ensure validity of RINs in the marketplace. EMTS allows for "real-time" reporting of RIN generation transactions, and the ability for small blenders to "delegate" their RIN-separation responsibilities to the party directly upstream. Please see Sections II and III of the final preamble for more detailed information on these and other registration, recordkeeping, reporting, and compliance requirements of the final rule.

## 7.6 Related Federal Rules

We are aware of a few other current or proposed Federal rules that are related to this rule. The primary related federal rules are: the first Renewable Fuel Standard (RFS1) rule (*72 FR 23900, May 1, 2007*), the RFS1 Technical Amendment Direct Final Rulemaking (*73 FR 57248, October 2, 2008*), and Control of Emissions from New Marine Compression-Ignition Engines at or Above 30 Liters per Cylinder (proposed rule: *74 FR 44442, August 28, 2009*; final rule: *signed December 22, 2009*).

## 7.7 Conclusions

Based on our outreach, fact-finding, and analysis of the potential impacts of our regulations on small businesses, we were able to estimate annual costs, and thus use this information to complete a preliminary screening analysis. To perform this analysis, we used a cost-to-sales ratio test (a ratio of the estimated annualized compliance costs to the value of sales per company). Costs were analyzed using average gasoline + diesel costs for the RFS2 program referenced to the AEO 2007 reference case for 2022, and also for 2010 and 2012.

For 2022, the cost-to-sales test indicated that all 17 small refiners would be affected at less than 1 percent of their sales (i.e., the estimated costs of compliance with the rule would be less than 1 percent, of their sales), and that these costs would actually be negative (or, a cost savings)—ranging from -3.15% to -0.94%. The gasoline and diesel costs for the 2022 scenario were estimated to be -2.35 and -12.07 cents per gallon, respectively.

Under the 2010 and 2012 scenarios, all small refiners were still affected at less than 1 percent, however the costs were no longer negative. For 2010, costs ranged from 0.24 to 0.84 percent of small refiners' sales, with estimated gasoline and diesel costs of 0.29 and 1.29 cents per gallon, respectively. For 2012, the costs were relatively similar for all small refiners—at 0.24-0.25 percent of their sales. The gasoline and diesel costs for 2012 were estimated to be 0.51 and 0.58 cents per gallon, respectively (the similarity in small refiners' costs-to-sales was due to this similarity in the estimated gasoline and diesel costs). Thus, costs for small refiners are generally anticipated to be less than one percent of their sales, and are expected to decrease over time, ultimately resulting in a cost savings by 2022. Note that while we did analyze a 2010 scenario, small refiners would not be participating in the program during this time, as the small refiner temporary exemption runs through December 31, 2010.

The cost estimates for all 3 scenarios do include the current available subsidies for the blending of ethanol of 45 cents per gallon for ethanol and $1.00 per gallon for biodiesel/renewable diesel, and the $1.01 per gallon producer credit for cellulosic biofuel, which depress the true cost of these renewable fuels in the marketplace.

For a complete discussion of the costs of the RFS2 rulemaking please see Chapter 4 of this Regulatory Impact Analysis.

# Appendix A: Biodiesel Effects on Heavy-Duty Highway Engines and Vehicles

## Executive Summary

Due to the continuing interest in the use of biodiesel fuels, the Environmental Protection Agency (EPA) has conducted a comprehensive analysis of the emission impacts of biodiesel using publicly-available heavy-duty, in-use diesel chassis and engine exhaust emissions data.

We investigated the emission impacts on NOx, PM, HC, and CO of 20 volume percent biodiesel fuels produced from various animal- and plant-based feedstock materials tested under several cycles in this analysis. Average NOx emissions were found to increase 2.2%, while PM, HC, and CO were found to decrease 15.6%, 14.1%, and 13.8% respectively, for all test cycles run on 20 vol% soybean-based biodiesel fuel at a significance level of $P < 0.05$ (See Table ES-A).

**Table ES-A.**
**Emission impacts for all cycles tested on 20 vol% soybean-based biodiesel fuel relative to an average base fuel**

| Emissions | Percent Change in Emissions |
|---|---|
| NOx | +2.2% |
| PM | -15.6% |
| HC | -14.1% |
| CO | -13.8% |

These results are consistent with the exhaust emission impacts for heavy-duty, in-use diesel engines found in our 2002 Draft Technical Report, entitled "*A Comprehensive Analysis of Biodiesel Impacts on Exhaust Emissions.*"

The current analysis also found that heavy-duty engine dynamometer data was statistically indistinguishable from heavy-duty chassis dynamometer data for NOx and HC at a significance level of $p < 0.05$. Likewise, results for Detroit Diesel Corporation (DDC) engines, used in many test programs, were found to be statistically similar to results for other engines for NOx, CO, and HC at a significance level of $p < 0.05$.

The results of the current analysis also point to a load-dependence of NOx emissions for heavy-duty highway engines and chasses. The difference in NOx emissions between our results here and those of other researchers appears to be attributable to an artifact of the selected test cycle profile. Analyzing the NOx emissions data as a function of load, as we do here -- as opposed to a particular test cycle profile -- reconciles the difference and supports the NOx emission-load-dependence hypothesis for heavy-duty highway engines and chasses posited by Sze *et al*. and corroborated by Eckerle *et al*.

# A1. Introduction

We investigated the emission impacts on NOx, PM, CO, and HC of 20 volume percent (vol%) biodiesel fuels produced from various feedstock materials tested under several vehicle and engine test cycles. The data used in this analysis is comprised of data used in EPA's 2002 Draft Technical Report, entitled "*A Comprehensive Analysis of Biodiesel Impacts on Exhaust Emissions Draft Technical Report*", hereafter referred to as the 2002 Draft Technical Report. Data from that report was supplemented with pertinent data sources published in the scientific and automotive literature between 2002 and 2007. The supplemental data was comprised of late model year engines, vehicles, and technology groups. A list of all data sources used in this analysis appears in the appendix to this document as does the 2002 Draft Technical Report.

The focus of the analysis proceeded from general to specific terms, through seven fuel-cycle combinations, summarized below. In Case 1, the most-general fuel-cycle combination, we examined all heavy-duty engine and chassis cycles run on plant- and animal-based biodiesel fuels; in Case 5a, 5b, and 5c, the most-specific fuel-cycle combinations, we examined heavy-duty engine and chassis data for light-, medium-, and heavy-duty cycles using soybean-based biodiesel. The latter analysis was designed to examine load-dependence of NOx emissions for heavy-duty highway engines and chasses first posited by EPA in 2007 (see Sze *et al*.). This research was further elucidated by Eckerle *et al*. While feedstock materials varied for the seven fuel-cycle combinations presented here, all analyses were conducted using 20 vol% biodiesel fuels.

A summary of fuel-cycle combinations used in the analysis appears below.

- Case 1: All cycles tested on plant-based (soybean, rapeseed/canola, and coconut) and animal-based (tallow, lard, and grease) biodiesel fuels,

- Case 2: All cycles tested on soybean-based biodiesel fuel,

- Case 3: FTP and UDDS cycles tested on soybean-based biodiesel fuel,

- Case 4: Detroit Diesel Corporation (DDC) and non-DDC engines tested on soybean-based biodiesel fuel,

- Case 5a: Engines and chasses tested on soybean-based biodiesel fuel run on light-duty cycles,

- Case 5b: Engines and chasses tested on soybean-based biodiesel fuel run on medium-duty cycles, and

- Case 5c: Engines and chasses tested on soybean-based biodiesel fuel run on heavy-duty cycles.

The results of the analysis of the seven fuel-cycle combinations appear in Section A3.2. The results of the analysis of the NOx emissions load-dependence appear in Section A3.3 and a discussion of the observed load-dependence impacts in the context of relevant literature and the 2002 Draft Technical Report appear in Section A3.4.

In the 2002 Draft Technical Report, we focused our analysis on data from heavy-duty highway engines, since this data was the most abundant in our database and since it was unclear to what extent testing on a chassis dynamometer might differ from testing on an engine dynamometer. However, some researchers criticized the conclusions of the report for its disproportionate reliance on engine data. These researchers argued that these engines may not behave in a manner indicative of the actual, in-use fleet or that chassis-generated data may be better-suited for NOx emissions testing.

Some researchers also criticized the conclusions of our 2002 Draft Technical Report, citing its disproportionate reliance on DDC engine data. These researchers argued that these engines may not behave in a manner indicative of the actual, in-use fleet as a whole. To help address these concerns, we supplemented the database for the 2002 Draft Technical Report with non-DDC engine data. In the current analysis, non-DDC engines represent 59.0% of all engines present in the supplemented database.

To investigate these concerns, we carried out an analysis to determine the compatibility of heavy-duty highway engine data with heavy-duty highway chassis data. Establishing compatibility between heavy-duty highway engine data and heavy-duty highway chassis data would allow us to make more-complete use of all emissions data in the database. In turn, this would allow us to perform more robust statistical analyses. The results of this engine and chassis data compatibility analysis are presented in Section A3.1. Section A2 contains a discussion of the data screening criteria and methodology used in this analysis.

## A2. Data Screening and Methodology

The data used in this analysis is comprised of data initially used in our 2002 Draft Technical Report, supplemented by pertinent data published between 2002 and 2007. The supplemental data included late model year engines, vehicles, and technology groups. A list of data sources used in this analysis appears in the appendix to this document.

A criticism raised by the 2002 Draft Technical report was that its analysis relied too heavily upon data from early model year engines and that these engines may not behave in a manner indicative of the actual, in-use fleet as a whole. To help address this concern, we supplemented the existing database of over 800 observations with approximately 560 additional observations comprised of late model year engines, vehicle, and technology groups.

Candidate data were first screened to verify that they met EPA data QC/QA requirements as well as criteria consistent with the goals of the analysis before inclusion into the database (See Section II of the 2002 Draft Technical Report for a discussion of EPA data QC/QA considerations). New data meeting these criteria were entered into the database developed for the 2002 Draft Technical Report. These criteria are described in Section A2.1.

## A2.1 Criteria for Selecting Data

Candidate data were screened to verify that they met criteria consistent with the goals of the analysis before inclusion into the database. For instance, the analysis was limited to No. 1 and No. 2 diesel fuel and related blends that can be used in typical heavy-duty diesel engines without engine modifications. As a result, all emulsions and non-biodiesel oxygenated blends with more than 20 vol% oxygenate were excluded from the final database used in the analysis. Also, synthetic fuels, such as those produced using the Fischer-Tropsch process, rather than refinery streams, were excluded from the final database.

We also limited this study to vehicles and engines that had already been sold commercially or had a high probability of being sold in the future. Vehicles and engines with experimental technologies that had no immediate plans for commercialization, such as those with innovative combustion chamber geometries, were excluded from the database. Likewise, single-cylinder research engines were excluded from consideration, even though the associated full-size parent engine might have been appropriately included in the database, had it been tested. Single-cylinder engines do not appear in heavy-duty applications. By definition, such engines have lower total horsepower and displacement, both of which may influence the way in which biodiesel impacts emissions.

The pairing of diesel and biodiesel fuels used in a particular study also played a role in determining if data from that study would be included in our analysis. For example, we excluded data from all studies that did not test at least two different biodiesel concentrations on the same engine, one of which could be 0 vol% biodiesel.

There were a number of instances in which data from one study was repeated in other studies. This might occur if the authors published the same dataset in multiple scientific journals to maximize exposure, or if the authors presented a previously-published set of data in a new publication for the purposes of comparing the two datasets. Such duplicative data was also excluded from our database.

Also, each prospective data source was screened to verify that it contained raw, not aggregated, data. In cases where raw data was not published in a study, attempts were made to obtain it from the study author(s). Raw data obtained from author(s) were included in our database after successful screening.

## A2.2 Criteria for Selecting Test Cycles

We selected cycles which were representative of actual, in-use operating conditions. While the Federal Test Procedure (FTP) transient cycle most-closely reflects actual, in-use operating conditions, we included data from a number of other studies that used atypical test cycles which were adequately comprehensive in their number, selection of modes, and/or in their transient speed-load traces, so that the resulting emission measurements may still be informative.

Data collected under test cycles that were unique, contained only a single steady-state mode, or used two- or three-nonstandard modes for testing, were typically excluded from the database.  Non-FTP/UDDS test cycles represented about 24 percent of all data in the database.

A total of eight different cycles, with two variants, representing a variety of load levels were included in our database.  A description of the test cycles included in our analysis appears below.

- AVL 8-Mode Test – An eight-mode steady-state engine test procedure, designed to correlate with FTP cycle exhaust emission results.  Only NOx emissions data generated by the AVL 8-Mode test was included in our database.

- Combined International Local Cycle and Commuter (CILCC) – A transient cycle developed by NREL for testing Class 4 to Class 6 vehicles.  It is intended to simulate urban delivery driving conditions for heavy-duty vehicles.

- City-Suburban Heavy-Vehicle Cycle (CSHVC) – A transient cycle developed by West Virginia University.  It is intended to simulate low-speed urban/ suburban driving conditions of heavy-duty vehicles and is punctuated with frequent stops.

- Freeway Cycle – A transient cycle intended to simulate four-lane highway driving conditions of heavy-duty vehicles, including entrance and exit ramps.

- Federal Test Procedure (FTP) – The heavy-duty transient cycle currently used by EPA for emission, certification, and other testing of heavy-duty on-road engines; the cycle most-closely reflects actual, in-use operating conditions and was developed to simulate a variety of heavy-duty truck and bus driving conditions in cities and on expressways.

- Highway Cycle (HWY) – A high-speed highway cruise cycle based on the Heavy Heavy-Duty Diesel Truck chassis cycle developed by the California Air Resources Board and previously used in the Coordinating Research Council E-55 program.

- Rowan University Composite School Bus Cycle (RUCSBC) – A school bus cycle developed by Rowan University.

- Urban Dynamometer Driving Schedule (UDDS) – A heavy-duty chassis dynamometer test.  Our database includes data from the UDDS cycle and two variants simulating light (6,000 lbs) and heavy (28,000 lbs) test weight conditions.

The summary of the test cycles included in our analysis appears in Table A2-A.

**Table A2-A. Test cycles included in this analysis**

| Test Cycle | Description | Duration |
|---|---|---|
| AVL 8 | Eight-mode steady-state cycle | n/a |
| CILCC | Heavy-duty urban delivery cycle | 53 min<br>12 sec |
| CSHVC | Heavy-duty city-suburb low-speed cycle | 28 min<br>20 sec |
| Freeway | Heavy-duty highway cycle | 27 min<br>20 sec |
| FTP | Heavy-duty engine certification cycle | 20 min |
| HWY | High-speed cruise cycle from CRC E-55 | 12 min<br>40 sec |
| RUCSBC | School bus cycle | 21 min<br>50 sec |
| UDDS | Heavy-duty chassis cycle | 17 min<br>40 sec |
| UDDS 6k | UDDS variant based on EPA data | 17 min<br>40 sec |
| UDDS 28k | UDDS variant based on CRC E-55 data | 17 min<br>40 sec |

### A2.3 Criteria for Selecting Feedstock Materials

Biodiesel fuel can be produced from a wide variety of feedstock materials. While the studies that comprise our database included only a portion of the many feedstock materials possible, they do represent the most-common feedstock materials. The biodiesel feedstock materials found in our database and their percentages are listed in Table A2-B.

**Table A2-B.**
**Biodiesel feedstock material observations in the database**

| Feedstock Materials | Number of Observations | Percentage of Observations |
|---|---|---|
| Soybean | 556 | 77.1% |
| Rapeseed/Canola | 95 | 13.2% |
| Grease* | 42 | 5.8% |
| Tallow | 19 | 2.6% |
| Coconut | 6 | 0.8% |
| Lard | 3 | 0.4% |

* Includes high free fatty acid (HFFA) and low free fatty acid (LFFA)

Given the limited data available for some feedstock materials, we aggregated all biodiesel feedstock materials into three general categories: plant-based biodiesel, soybean-based biodiesel (a subset of plant-based biodiesel), and animal-based biodiesel (See Table A2-C for a listing of biodiesel feedstock materials aggregated into the categories used in our database).

**Table A2-C.**
**Biodiesel feedstock materials aggregated into categories used in the database**

| Aggregated Feedstock Material Category | Number of Observations in Category |
|---|---|
| Plant-based | 657 |
| Soybean-based | 556 |
| Animal-based | 64 |

## A2.4 Overview of methodology

This section summarizes the statistical approach used in this analysis, which employed the SAS/STAT software procedure PROC MIXED. This procedure can treat some variables as fixed-effects and others as random-effects.

For instance, the NOx fixed-effect was expressed as a function of percent biodiesel (0 or 20 vol%), vehicle class (Class 1-2a or Class 2b-8), the interaction of percent biodiesel and vehicle class, test cell type (chassis test cell or engine test cell), and the interaction between test cell type and percent biodiesel. Each fixed-effect term is tested and removed if found not significant. Additional fixed-effect terms were added to the model when examining DDC and non-DDC engines. The random-effects examined were the test cell type and its interaction with percent biodiesel, test cycle, and the biodiesel source.

After creating the initial model, the distribution of mixed-model residuals are examined; residuals with absolute values greater than four standard deviations from a mean of 0 are considered outliers and removed from further consideration.

The final model evaluates the statistical significance of the difference between fuels containing 20 vol% biodiesel and the base fuel, containing no biodiesel. A significance criterion of $p < 0.05$ was used for all analysis. See Section II of the 2002 Draft Technical Report for additional discussion and derivations.

## A3. Results

This section contains the results of the biodiesel emissions impact analysis described in Section A2. The results of the analysis of the compatibility of heavy-duty highway chassis and engine data appear in Section A3.1. The results of the analysis of the seven fuel-cycle combinations appear in Section A3.2, including the analysis of DDC engines versus non-DDC engines. The results of the analysis of the NOx emissions load-dependence appear in Section A3.3 and a discussion of the observed load-dependence impacts placed in the context of relevant literature and the 2002 Draft Technical Report appear in Section A3.4.

### A3.1 Compatibility of Heavy-duty Highway Chassis and Engine Data

The primary objective of the analysis was to quantify the impacts of biodiesel fuels. One aspect of the analysis was to determine if heavy-duty highway emissions engine data in our database was comparable to heavy-duty highway chassis data for purposes of our statistical analysis. Much of the database (66%) consisted of heavy-duty highway engine data, with the balance of the data comprising heavy-duty highway chassis data. Establishing compatibility between engine and chassis data would allow us to make more complete use of all emissions data in the database, which, in turn, would allow us to perform more robust statistical analyses.

Moreover, some researchers criticized the conclusions of our 2002 Draft Technical Report, citing its disproportionate reliance on engine data. These researchers argued that these engines may not behave in a manner indicative of the actual, in-use fleet as a whole or that chassis-generated data might be better-suited for purposes of biodiesel emissions testing. To investigate these claims, we undertook an analysis to determine the compatibility of heavy-duty highway engine data with heavy-duty highway vehicle data.

Using a significance level of $p < 0.05$ for all statistical analysis, engine data was found to be statistically comparable to chassis data for NOx and CO emissions. This finding is supported by the research of NREL, whose examination of published data suggests that there exists no discrepancy between engine and vehicle testing data (See NREL Milestone 10.4). See Table A3-

A for a summary of fuel-cycle combinations for which heavy-duty highway engine data was statistically comparable to heavy-duty highway chassis data for regulated pollutants.

**Table A3-A.**
**Fuel-cycle combinations for which heavy-duty highway engine data was statistically comparable to heavy-duty highway chassis data for regulated pollutants**

| | | Regulated Pollutants | | | |
|---|---|---|---|---|---|
| | | **NOx** | **PM** | **CO** | **HC** |
| **Fuel-Cycles** | Case 1 | **x** | | | **x** |
| | Case 2 | **x** | | | **x** |
| | Case 3 | **x** | | | **x** |
| | Case 4 | **x** | | | **x** |
| | Case 5a | **x** | | | **x** |
| | Case 5b | **x** | | | **x** |
| | Case 5c | **x** | | | **x** |

**x** Denotes heavy-duty highway engine data that is statistically comparable to heavy-duty highway chassis data.

Emissions of PM and CO for heavy-duty highway engines and chasses were not found to be statistically comparable to each other for any of the seven fuel-cycle combinations. Based upon our experience with chassis test cells, it is difficult to accurately quantify PM exhaust emissions, as chassis-based testing is often deficient and non-standardized vis-à-vis 40CFR86-2007 and 40CFR1065 for test specification and test equipment, respectively. Deficiencies associated with non-standardized chassis test cells may produce high test-to-test variability. Likewise, CO emissions are difficult to accurately quantify on both heavy-duty engine and chassis test cells and may also produce high test-to-test variability.

High test-to-test variability curtails the ability to accurately capture and discern small differences in exhaust emissions, particularly PM and CO exhaust emissions. This variability may help to explain why engine and chassis data are not comparable in our analysis for CO and PM emissions.

In cases where heavy-duty highway engine data is statistically comparable to heavy-duty highway chassis data, engine and chassis data are pooled to produce the appropriate statistic. In other cases, we believe that the use of engine data alone results in a more-representative statistic, which we report here. The results for the following analysis reflect this approach.

### A3.2 Fuel-cycle Results

Seven fuel-cycle combinations were identified for our statistical analysis, ranging from a general case, combining testing of all test cycles and all cycles and on all biodiesel fuel feedstock materials to cycles aggregated into light-, medium-, and heavy-duty test cycle categories, which were run exclusively on 20 vol% soybean-based biodiesel fuel. Heavy-duty highway engine and chassis emissions data were statistically comparable for NOx and HC and were subsequently pooled for our analysis. Heavy-duty highway engine and chassis emissions data were not statistically comparable for PM and CO, so only engine results are presented here. The results for each of the seven fuel-cycle combinations appear below. All results presented are statistically significant at a significance level of $p < 0.05$.

### Case 1: All cycles tested on all biodiesel fuels

Our first fuel-cycle combination examined data collected on all cycles included in the database and from all vehicles and engines tested on both plant-based (soybean, rapeseed/canola and coconut) and animal-based (tallow, lard, and grease) biodiesel fuels (See Table A2-A for a listing of all cycles used in the Case 1, Case 2, and Case 4 analyses).

For plant-based and animal-based biodiesel fuels, NOx emissions were found to increase a statistically-significant 2.0% relative to the base fuel, whereas, PM, CO, and HC emissions were found to decrease by 13.6%, 13.5%, and 18.7%, respectively, relative to the base fuel.

### Case 2: All cycles tested on soybean-based biodiesel fuels

Our second fuel-cycle combination examined all cycles specified in Case 1, but only involved vehicles and engines tested on soybean-based biodiesel fuels.

For soybean-based biodiesel, NOx emissions were found to increase by 2.2%, whereas PM, CO, and HC emissions were found to decrease by 15.6%, 13.8%, and 14.1%%, respectively, relative to the base fuel. Case 1 and Case 2 differ in their fuel composition. The biodiesel tested in Case 1 is composed of 20 vol% animal- and plant-based biodiesel, whereas in Case 2, the fuel is composed of 20 vol% soybean-based biodiesel only. The results suggest that the removal of animal-based and/or rapeseed/canola/coconut-based biodiesel fuel feedstock materials may have a slight impact on some exhaust emissions. Increases in emissions of 0.2 %, 2.0%, and 0.3% are observed for NOx, PM, and CO, respectively, relative to a soybean-based biodiesel discussed in Case 2. HC emissions decrease by 4.6% relative to a soybean-based biodiesel.

Several hypotheses have been advanced by researchers in an attempt to help explain the differences in exhaust emissions between plant-based and animal-based biodiesel feedstock materials (See Graboski *et al*. and Goetz); these are, however, outside the scope of the current analysis and are not discussed here.

### Case 3: FTP and UDDS cycles tested on soybean-based biodiesel fuels

Our third fuel-cycle combination examined only engines and vehicles tested on soybean-based biodiesel fuel over only the FTP and UDDS cycles. Together, FTP and UDDS cycles comprise 76% of the database observations.

For soybean-based biodiesel, NOx emissions were found to increase by 3.2%, whereas PM, CO, and HC emissions were found to decrease by 15.6%, 15.9%, and 13.7%, respectively, relative to the base fuel.

The results of this analysis suggest that the emission impacts associated with heavy-duty highway engines and chasses tested on 20 vol% soybean-based biodiesel and run on FTP/UDDS cycles produce an increase in exhaust emissions of 1.0% for NOx and 2.1% for CO, relative to all engine and chassis cycles run on the same fuels. HC emissions decrease by 0.4% relative to all engine and chassis cycles and PM emissions appear to be relatively unaffected. These results were statistically significant at a significance level of $p < 0.05$.

As the FTP and UDDS cycles may more-closely represent actual, in-use operating conditions encountered by heavy-duty highway engines and vehicles, it is possible that the Case 3 results may be a better indicator of actual, in-use biodiesel emissions impacts.

### Case 4: DDC vs. non-DDC engines tested on soybean-based biodiesel fuels

Our fourth fuel-cycle combination separately examined DDC and non-DDC engines tested on the cycles specified in Case 1 and Case 2 using soybean-based biodiesel fuel.

Our analysis found that DDC heavy-duty engine data was statistically comparable to non-DDC heavy-duty engine data for NOx, CO, and HC emissions at a significance level of $p < 0.05$. DDC heavy-duty engines and non-DDC heavy-duty engines did not behave in a statistically similar manner for PM emissions, however. In this regard, the results of our analysis suggest that DDC heavy-duty engines behave in the same manner in which non-DDC heavy-duty engines behave in our database for NOx, CO, and HC emissions. As such, this finding should help alleviate earlier concerns that the disproportionate representation of DDC engines may produce results which are not indicative of the database as a whole or the in-use fleet.

### Case 5a: Light-duty cycles tested on soybean-based biodiesel fuels

Our fifth fuel-cycle combination examined heavy-duty engine and chassis data for light-duty cycles specified in Table A3-B and tested on soybean-based biodiesel fuel.

For soybean-based biodiesel tested on light-duty cycles, NOx, PM, CO, and HC emissions were found to decrease by 1.0%, 19.0%, 9.9%, and 14.2% respectively, relative to the base fuel.

**Table A3-B. Cycle composition by case**

| Case Number | Case Description | Individual Cycles |
|---|---|---|
| Case 5a | Light-duty cycles | CILCC<br>CSHVC<br>UDDS6k |

|  |  |  |
|---|---|---|
| Case 5b | Medium-duty cycles | AVL8 (NOx)<br>Freeway<br>FTP<br>RUCSBC<br>UDDS<br>UDDS28k |
| Case 5c | Heavy-duty cycles | HWY55 |

Case 5b: Medium-duty cycles tested on soybean-based biodiesel fuels

Our sixth fuel-cycle combination examined heavy-duty engine and chassis data for medium-duty cycles specified in Table A3-B and tested on soybean-based biodiesel fuel.

For soybean-based biodiesel tested on medium-duty cycles, NOx emissions were found to increase by 2.5%, relative to the base fuel, whereas PM, CO, and HC emissions were found to decrease by 19.0%, 14.0%, and 14.2%, and respectively, relative to the base fuel.

Case 5c: Heavy-duty cycles tested on soybean-based biodiesel fuels

Our seventh fuel-cycle combination examined heavy-duty engine and chassis data for heavy-duty cycles specified in Table A3-B and tested on soybean-based biodiesel fuel.

For soybean-based biodiesel tested on heavy-duty cycles, NOx emissions were found to increase by 5.1%, relative to the base fuel, whereas PM, CO, and HC emissions were found to decrease by 32.6%, 22.0%, and 14.2%, respectively, relative to the base fuel. Unlike Case 5a and 5b, the PM emissions results were significant and greater than those of the light-duty and medium-duty cases. A summary of these results appears in Table A3-C.

**Table A3-C.**
**Summary of emissions results for seven fuel-cycle combinations for heavy-duty highway engines and chasses**

| | | Regulated Pollutants | | | |
|---|---|---|---|---|---|
| | | **NOx** | **PM[*]** | **CO[*]** | **HC** |
| **Fuel-Cycles** | Case 1 | +2.0% | -13.6% | -13.5%[+] | -18.7% |
| | Case 2 | +2.2% | -15.6% | -13.8% | -14.1% |
| | Case 3 | +3.2% | -15.6% | -15.9% | -13.7% |
| | Case 4 | +2.4% | -16.9% | -13.9% | -14.3% |
| | Case 5a | -1.0% | -19.0% | -9.9% | -14.2% |
| | Case 5b | +2.5% | | -14.0% | |
| | Case 5c | +5.1% | -32.6% | -22.0% | |

* Only engine data.
\+ Not significant.

## A3.3 Load-dependent Emissions Impacts

We initially identified the load-dependence of NOx emissions in heavy-duty highway engines in 2007 (See Sze *et al.*) and these results were later corroborated by Eckerle *et al*. The results of Sze *et al.* and Eckerle *et al*. were based largely upon new engine and chassis studies (as well as modeling efforts), which were aimed specifically at examining the load-dependent NOx emissions phenomenon.

In the current research, however, our work is retrospective insofar as we examined data from a broad array of pre-existing studies, none of which were designed to examine the load-dependent NOx emissions impacts. As such, this analysis occasionally suffers from the experimental design limitations associated with the pre-existing studies. One such limitation is the use of test cycles which do not realistically reflect actual, in-use operating conditions. Such data can skew results and obscure evidence of the load-dependence of NOx emissions. Such a situation is discussed in Case 5a.

### Case 5a, 5b, and 5c: Load-dependent emissions impact on NOx

The load-dependence of NOx emissions observed in this analysis is apparent when comparing Case 5a (light-load cycles) to Case 5b (medium-load cycles) to Case 5c (heavy-load cycles). However, results for the light-load conditions in Case 5a may not be representative of in-use vehicle operation.

### Case 5a: Confounding effects of lightly-loaded conditions

The load-dependence of NOx emissions evident in the research of Sze *et al.* and Eckerle *et al.* was based upon medium- and heavy-duty cycles, not lightly-loaded cycles as in Case 5a.

We believe that our current findings for NOx emissions under lightly-loaded conditions may not be representative of the operating conditions typically encountered in actual, in-use fleet operations. As in-use heavy-duty highway engines and vehicles do not typically operate under the lightly-loaded conditions encountered in the cycles which comprise our light-duty category, the practical significance of the NOx emissions results for Case 5a is questionable.

Further, the NOx emissions results for Case 5a are also suspect when compared to Cases 1-4 and 5b-5c, all of which indicate that there is a statistically-significant increase in NOx emissions of between 2.0% and 5.1%.

As such, we place greater significance on the results obtained under medium- (Case 5b) and heavy-load (Case 5c) conditions, since they more-accurately mirror typical, in-use fleet operations and, as a result, provide a more realistic representation of operating conditions encountered in-use.

Case 5b vs. Case 5c: Load-dependent NOx emission impacts

Since the medium-loading conditions associated with these cycles are typical of actual, in-use fleet operations, these cycles provide a more realistic representation of operating conditions encountered by actual fleet usage. As such, we place greater significance on these results.

The difference in NOx emissions between our results here and those of other researchers appears to be attributable to an artifact of the selected test cycle profile. Analyzing the NOx emissions data as a function of load, as we do here -- as opposed to a particular test cycle profile -- reconciles the difference and supports the NOx emission-load-dependence hypothesis for heavy-duty highway engine and chasses posited by Sze *et al*. and corroborated by Eckerle *et al*. The discussion of load-dependent NOx emission impacts in the context of our research appears in Section A3.4.

### A3.4 Relevant Studies

We initially identified the load-dependence of NOx emissions in heavy-duty highway engines in 2007 (See Sze *et al.*) and these results were later corroborated by Eckerle *et al*. The results of Sze *et al.* and Eckerle *et al*. were based largely upon new engine and chassis studies (as well as modeling efforts), which were aimed specifically at examining the load-dependent NOx emissions phenomenon.

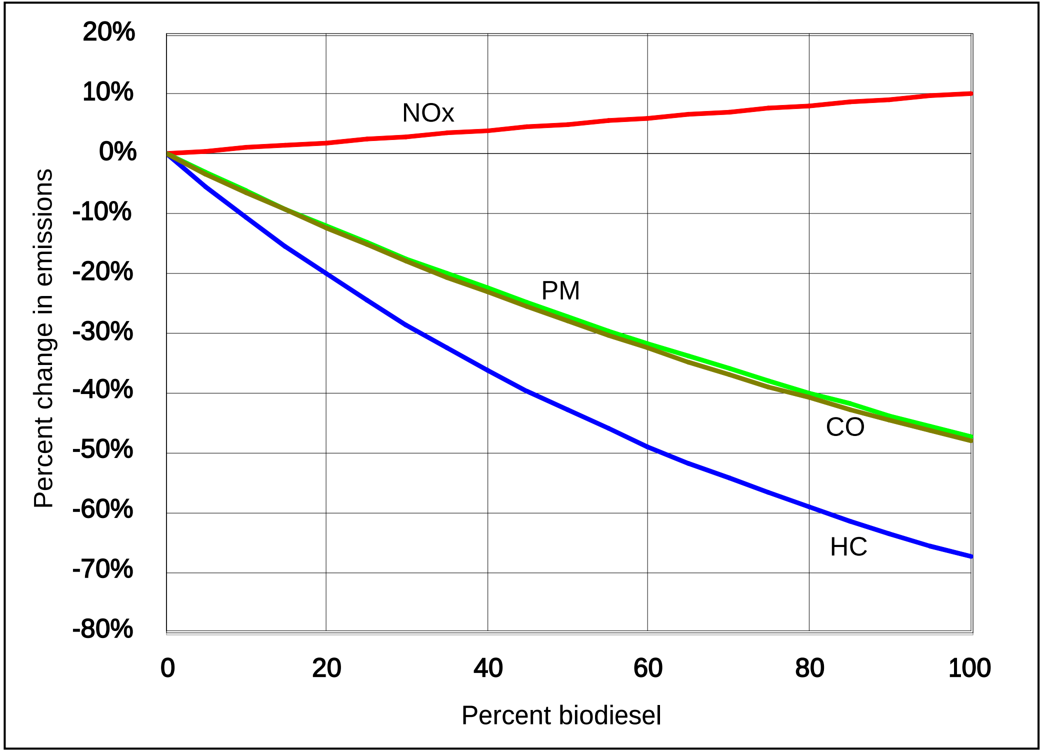
In the current research, however, our work is retrospective insofar as we examined data from a broad array of pre-existing studies, none of which were designed to examine the load-dependent NOx emissions impacts. As such, this analysis occasionally suffers from the experimental design limitations associated with the pre-existing studies. One such limitation is the use of test cycles which do not realistically reflect actual, in-use operating conditions. Such data can skew results and obscure evidence of the load-dependence of NOx emissions. Such a situation is discussed in Case 5a.

*2002 Draft Technical Report*

In 2002, the EPA conducted a comprehensive analysis of the emission impacts of biodiesel using publicly available data. Entitled "*A Comprehensive Analysis of Biodiesel Emissions Impacts on Exhaust Emissions*," the 2002 Draft Technical Report made use of statistical regression analysis to correlate the concentration of biodiesel in conventional diesel fuel with changes in regulated and unregulated pollutants for heavy-duty highway engines.

Figure A3-A presents basic emission correlations for NOx, PM, CO, and HC developed in the 2002 Draft Technical Report as a function of soybean-based biodiesel concentration. Table A3-D presents results specifically for 20 vol% soybean-based biodiesel.

### Figure A3-A.
### Emission impacts from the 2002 Draft Technical Report by percent biodiesel content for soybean-based biodiesel added to an average base fuel

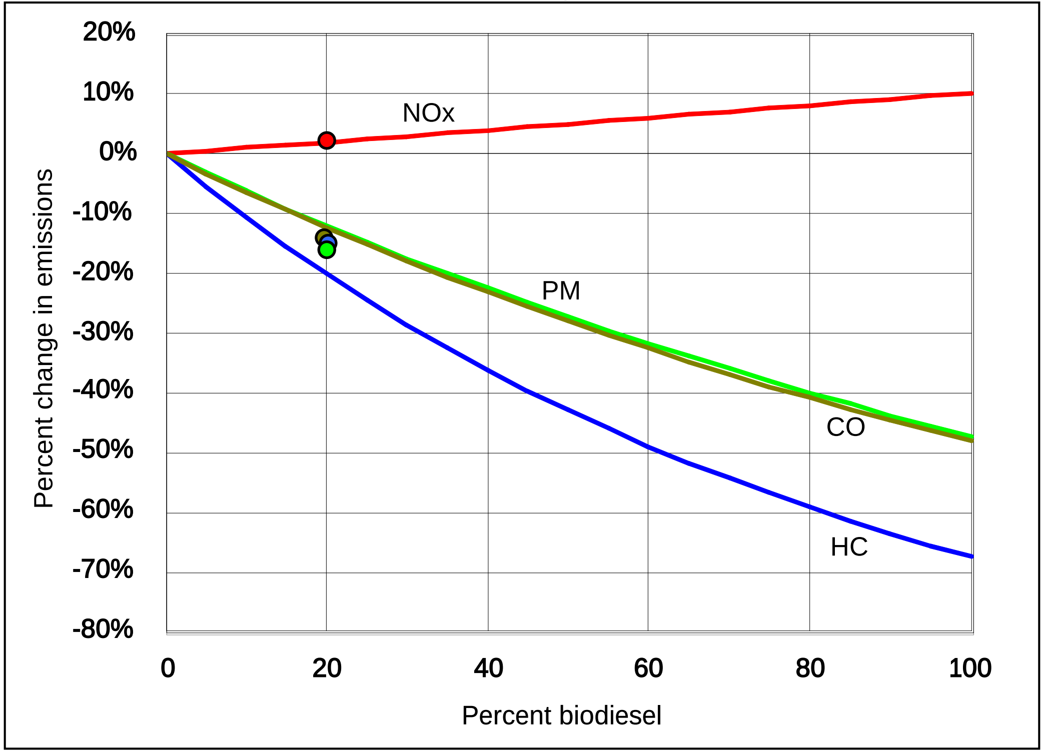


### Table A3-D.
### Emission impacts from the 2002 Draft Technical Report for 20 vol% soybean-based biodiesel added to an average base fuel

| Emissions | Percent Change in Emissions |
|---|---|
| NOx | +2.0% |
| PM | -10.1% |
| HC | -21.1% |
| CO | -11.0% |

We found that the results of the current analysis, which examined heavy-duty highway engine and chassis data, are consistent with the findings of our 2002 Draft Technical Report, which examined heavy-duty highway engine data only. Compared to the 2002 Draft Technical Report, NOx emissions were found to increase 2.2% while PM, HC, and CO emissions were found to decrease by 15.6%, 14.1%, and 13.8%, respectively, in the current study. These are shown in Figure A3-B as points overlaid on the results of the 2002 Draft Technical Report.

**Figure A3-B.**
**Emission impacts from the 2002 Draft Technical Report by percent biodiesel content for soybean-based biodiesel added to an average base fuel with new results overlaid**

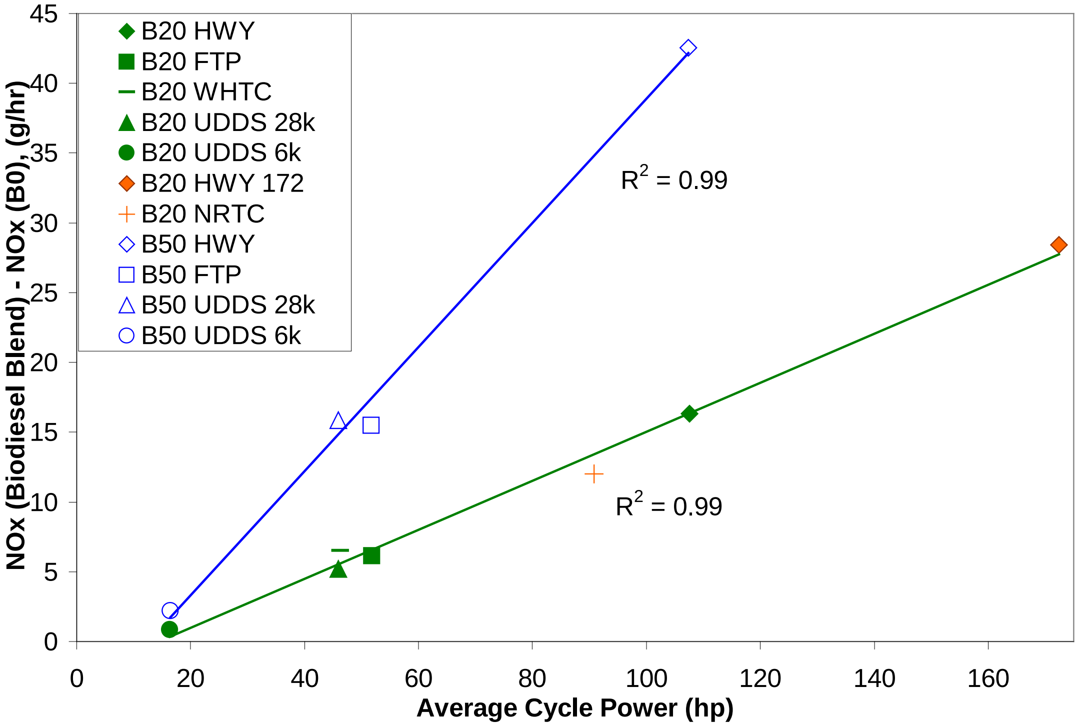


*SAE paper by Sze et al.*

Sze *et al*. conducted a series of paired fuel tests comparing certification-grade highway diesel fuels with 5 to 50 vol% soybean-based biodiesel blends. Each fuel pair was tested for up to seven transient cycles representing various load conditions, using a 2006 model year Cummins ISB compression ignition engine.

The authors concluded that biodiesel NOx impact on the test engine is directly proportional to average cycle power or fuel consumption and biodiesel content (See Figure A3-C).

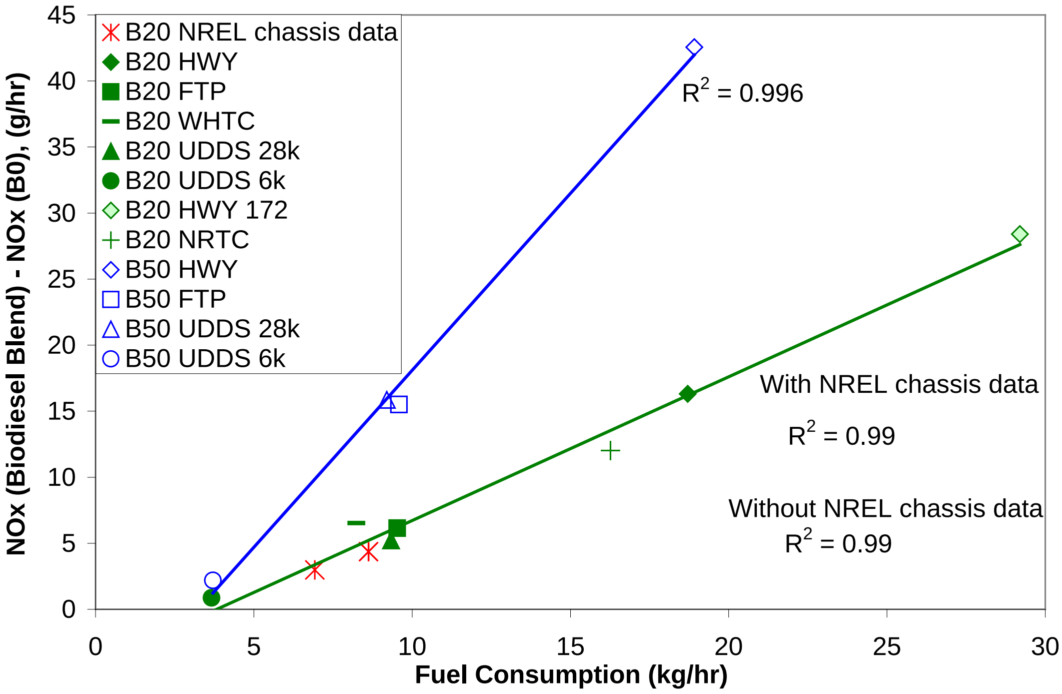
**Figure A3-C.**
**NOx emissions for 20 vol% and 50 vol% soybean-based biodiesel fuel versus average cycle power for various heavy-duty highway engine and chassis cycles**



Except for the most lightly-loaded cycle, the results show statistically significant differences in NOx emissions for all fuel pairs. The average NOx emissions due to biodiesel were found to increase over each cycle, ranging from 0.9 to 6.6% for 20 vol% and 2.2 to 17.2% for 50 vol% biodiesel fuels. The load-dependence of NOx emissions observed by Sze *et al*. is consistent with the findings presented in this report for Cases 5a, 5b, and 5c as well as those of Eckerle *et al*.

To further elucidate the load-dependent nature of NOx emissions, Sze *et al*. reanalyzed chassis-generated NOx emissions data from NREL as a function of fuel consumption (a surrogate for average cycle power) and found it to be in close agreement with EPA engine test data. This is depicted in Figure A3-D. Data from NREL using the same engines tested instead on a chassis dynamometer are also shown in the figure and follow the same trend, with an $R^2$ = 0.99 with and without the inclusion of the NREL dataset.

## Figure A3-D.
## NOx emissions for 20 vol% soybean-based biodiesel fuel versus average cycle power for various heavy-duty highway engine and chassis cycles, including NREL chassis testing data



*SAE paper by Eckerle et al.*

The load-dependence of NOx emissions was also examined by Eckerle *et al.*, who generated engine data using 20 vol% soybean-based biodiesel to calibrate chemical kinetic models. These models were used to examine NOx production during the combustion process. The authors concluded that the NOx effect associated with burning biodiesel blends over a duty cycle depends, in part, on the duty cycle average power and that higher duty cycle average power corresponded to larger increases in NOx emissions.

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