Evaluation of the Environmental Protection Agency Treatment of Life Cycle Assessment in the Renewable Fuel Standard Rulemaking

Prepared by
Stefan Unnasch, Brent Riffel, Larry Waterland, Life Cycle Associates
Christopher Loreti, The Loreti Group

for

American Petroleum Institute
1220 I Street, NW
Washington, DC 20005

Life Cycle Associates, LLC

DISCLAIMER

This report was prepared by Life Cycle Associates, LLC and The Loreti Group for the American Petroleum Institute (API). Life Cycle Associates and The Loreti Group are not liable to any third parties who might make use of this work. No warranty or representation, express or implied, is made with respect to the accuracy, completeness, and/or usefulness of information contained in this report. Finally, no liability is assumed with respect to the use of, or for damages resulting from the use of, any information, method or process disclosed in this report. In accepting this report, the reader agrees to these terms.

ACKNOWLEDGEMENT

Table of Contents

List of Tables

List of Figures

Terms and Abbreviations:

AERI	Alberta Energy Research Institute
ANL	Argonne National Laboratory
API	American Petroleum Institute
ARB	California Air Resources Board
BESS	Biofuel Energy Simulator System
Btu	British thermal unit
CAPP	Canadian Association of Petroleum Producers
CARFG	California reformulated gasoline
CDM	Clean Development Mechanism
CI	Carbon Intensity
CMI	Census of Mineral Industries
CREM	Council for Regulatory Environmental Modeling
DDGS	Dry distiller's grains and solubles
DGS	Distiller's grains and solubles
DME	Dimethyl ether
DOE	U.S. Department of Energy
DRIA	Draft Regulatory Impact Assessment
EERE	U.S. DOE's Office of Energy Efficiency and Renewable Energy
EIA	U.S. DOE's Energy Information Agency
EISA	Energy Independence and Security Act
EPA	U.S. Environmental Protection Agency
FAO	Food and Agriculture Organization
FAME	Fatty acid methyl esters
FAPRI	Food and Agricultural Policy Research Institute, Iowa State University's Center for Agricultural and Rural Development (CARD) and the University of Missouri-Columbia
FASOM	Forest and Agricultural Sector Optimization Model
FTD	Fischer-Tropsch diesel
GHG	Greenhouse gas
GREET	Greenhouse gas, Regulated Emissions and Energy Use in Transportation (ANL well-to-wheels LCA model)
GTL	Gas to liquid
GWP	Global warming potential
HHV	Higher heating value
IEA	International Energy Agency

IPCC	Intergovernmental Panel on Climate Change
ISO	International Organization for Standardization
JRC	Joint Research Centre
kWh	Kilowatt hour
LCA	Life cycle assessment
LCFS	Low-carbon fuel standard
LCI	Life cycle inventory
LEM	Lifecycle emissions model
LHV	Lower heating value
LUC	Land use change
Mgpy	Million gallons per year
MJ	Mega joule
mmBtu	Million Btu
MMSCF	Million standard cubic feet
MSW	Municipal solid waste
NEMS	National Energy Modeling System
NETL	National Energy Technology Laboratory
NREL	National Renewable Energy Laboratory
NRC	Nuclear Regulatory Council
NPRM	Notice of Proposed Rulemaking
OSTR	Oil Sands Technology Roadmap
RFG	Reformulated gasoline
RFS	Renewable Fuel Standard
RIA	Regulatory Impact Assessment
RPS	Renewable portfolio standard
SAGD	Steam assisted gravity drainage
SCO	Synthetic crude oil
SOC	Soil organic carbon
tonne	Metric ton, 1000 kg
TPD	Tons per day
TTW	Tank to wheel
USDA	U.S. Department of Agriculture
WDGS	Wet distiller' grains and soluble
WTT	Well to tank
WTW	Well to wheels

1   Introduction

This report examines the United States Environmental Protection Agency's (EPA) treatment of key issues involved with alternative transportation fuels emissions analyses and standards in its *Draft Regulatory Impact Analysis (DRIA): Changes to Renewable Fuel Standard Program*, published in May 2009. The DRIA serves as supporting documentation for the revised renewable fuels standard (RFS2) proposed in the Notice of Proposed Rulemaking (NPRM) co-released in May 2009. In the DRIA, EPA is focused on a number of key points regarding renewable transportation fuels and greenhouse gas emissions (GHG) analyses.

EPA is using a variety of agricultural and process engineering models and spreadsheet analysis tools, including the Greenhouse Gas, Regulated Emissions, and Energy Use in Transportation (GREET) model, the Global Trade Analysis Project (GTAP) model, the Forest and Agricultural Sector Optimization Model (FASOM), and the Food and Agricultural Policy Research Institute (FAPRI) tools, to further analyze life cycle impacts of renewable fuels. This report provides a detailed assessment of EPA's analysis of greenhouse gas (GHG) emissions using a life cycle analysis (LCA) framework, and will review models and data included in the DRIA and other EPA documentation.

EPA states that the LCA discussed in the DRIA is a consequential LCA instead of the attributional LCA relied upon in the RIA for the RFS1 rule adopted in 2007. An attributional LCA is one that accounts for flows/impacts of pollutants, resources, and exchanges among processes within a chosen temporal window. Whereas a consequential LCA is one that attempts to account for flows/impacts that are caused beyond the immediate system in response to a change to the system. Thus, for example, in the consequential LCA, the effects of the changes in the fuel production system between the baseline and the ―with biofuel" cases are as important as the emissions associated with each individual fuel. The detailed assessment discussed in this report also addresses features of the EPA consequential LCA used in the DRIA.

1.1   Background

In December of 2007, President Bush signed the Energy Independence and Security Act (EISA) into law. One of the provisions of this law mandates that by the year 2022, at least 36 billion gallons of the transportation fuels marketed in the U.S. be renewable fuels. The law requires that the various types of renewable fuels used to fulfill this requirement meet certain performance standards for their life cycle GHG emissions relative to conventional gasoline and diesel fuel sold in 2005. It defines life cycle emissions as the total quantity of GHG emissions, including direct and significant indirect emissions, related to the full fuel life cycle from feedstock generation or extraction through the distribution and delivery and use of the fuel by the final consumer.

EPA is charged with developing the regulations for the renewable fuel standard of EISA, and the EPA Administrator is responsible for determining the life cycle GHG emissions for the baseline petroleum fuels and the renewable fuels. Because the required GHG emission reductions for the renewable fuels are defined with respect to conventional petroleum fuels, it is important that EPA properly account for the life cycle GHG emissions from the petroleum fuels.

1.2   Objectives

Under contract to the American Petroleum Institute (API), Life Cycle Associates, LLC and The Loreti Group are reviewing EPA's support documents for the renewable fuel standard of EISA. The proposed regulations were released in May of 2009. EPA previously described its approach to analyzing petroleum fuel pathways related to the May 2007 Executive Order on renewable and alternative fuels (which has been superseded by EISA), and it shared with API its intended approach to assessing the life cycle GHG emissions from petroleum fuels under EISA. Therefore, API requested that this review begin prior to the release of the draft regulations.

The revised renewable fuel standard (RFS2) requires the equivalent of 36 billion gallons of renewable and other alternative fuels by 2022. This is nearly five times the target for 2012 established under RFS1. The approach to measurement of GHG emissions targets is the focus of this analysis and report.

As part of proposed revisions to the RFS, EPA analyzed lifecycle GHG emissions from increased renewable fuels use. This LCA focus represents unchartered territory for EPA and has drawn on considerable opinions amongst stakeholders during their review process. The regulatory purpose of the lifecycle greenhouse gas emissions analysis is to determine whether renewable fuels used in the analysis meet the GHG thresholds for the different fuel categories, and to outline the predominant issues arising from the transportation fuel analyses and the included life cycle analyses. Land use studies, including the treatment of direct and indirect effects, are discussed from a domestic and global perspective. This report analyzes the key parameters employed in the analyses, with particular emphasis on the model inputs.

Traditional, process-based life cycle analyses of biofuels do not account for the release of carbon stored in the above ground flora and in the soil resulting from increased biofuels production. However, a complete analysis of GHG impacts of a policy such as the RFS must consider these factors. Performing such a life cycle analysis involves counting the emissions associated directly with the clearing of land to grow crops as well as the indirect effects that occur when biofuels production displaces crops that would otherwise be grown for food (or industrial products such as cotton and lumber).

EPA's analysis of the land use impacts of expanded corn ethanol production uses the FASOM and FAPRI agricultural-economic models. The models predict changes in crop outputs and, coupled with assumptions about which land will be brought into production, estimate the corresponding changes in land use in the U.S. and internationally, and the resulting changes in GHG emissions. These analyses provide a framework for examining the potential GHG emissions associated with biofuels and the marginal sources of land associated with corn production. However, many risks and uncertainties are embedded in the calculations, which require further examination before the GHG impacts of an expanded use of biofuels are understood. The input assumptions, transparency, and uncertainty analysis require further examination before this effort can be considered a reasonable assessment of the impact of biofuels. A more detailed assessment of the specific elements of EPA's analysis is provided in the following sections of this report.

2 Review of Biofuel Pathways

The biofuel pathways considered in our analysis are summarized in Table 2.1. Discussion of the details of EPA's evaluation of these pathways as documented in their Draft Regulatory Impact Analysis: Changes to Renewable Fuel Standard Program (DRIA, EPA 2009) is given in the following subsections. The discussion focuses on the lifecycle analyses (LCAs) EPA performed using the Greenhouse Gas, Regulated Emissions, and Energy Use in Transportation (GREET) model developed by Argonne National Laboratory (ANL). Following this discussion is a review of some issues relating to their analysis.

Table 2.1. Fuel Pathways Considered in the EPA DRIA.

Fuels	Feedstock	Production Configurations
Ethanol Biobutanol	Corn	Dry mill
		Wet mill
	Sugar Cane	Fermentation
	Other starch crops	Fermentation
	Woody Energy Crops	Enzymatic hydrolysis
	Herbaceous Energy Crops	Acid hydrolysis
	Waste Material	Gasification
		Fermentation
Biodiesel Renewable Diesel	Soybean oil	Esterification
	Waste Fats	Hydroprocessing
	Palm Oil	
	Canola (Rapeseed)	
	Algae	

2.1 Ethanol Pathways

EPA considers a mix of ethanol pathways to comply with the EISA requirements. These include those that use existing feedstock-to-ethanol conversion technologies, such as corn ethanol and Brazilian sugar cane ethanol, as well as a range of ethanol pathways that are under development including cellulosic ethanol from a variety of materials, and other ethanol pathways. EPA's analysis of factors affecting the viability of the ethanol pathways and inputs for GHG analysis are reviewed here.

2.1.1. Technology Assumptions

Cost, energy inputs, and other factors that affect the viability of alternative fuels are described in the DRIA. These factors directly or indirectly affect life cycle GHG emissions. For example, the capital cost of fuel production facilities would affect the ability of fuel producers to sell fuel or afford feedstocks to compete with petroleum. Fuel production costs would also impact the economic analysis of ethanol plants.

In a number of instances the DRIA relies on costs that reflect optimistic assumptions for the nth plant. For example, the National Renewable Energy Laboratory (NREL) examined the cost of cellulosic ethanol plants with technology assumptions corresponding to timing (Tao and Aden 2008, Aden et al. 2002, Phillips et al. 2007). These are familiar projections for enzymatic hydrolysis processes that have not been proven. Cellulosic ethanol plants have not advanced as rapidly as projected with project financing and other challenges (Garthwaite 2009).

EPA also provides an extensive examination of the potential for corn ethanol plant based on specific design configurations (dry mill, wet DGS, corn oil separation). The energy inputs associated with these specific technology options appear reasonable; however, the construction of future plants and modification of existing corn ethanol plants according to EPA's scenario is not assured. These uncertainties affect all aspects of the GHG analysis including investment in other technologies, ethanol plant yields and related land use conversion, and indirect effects associated with fossil fuel use.

In the DRIA, EPA emphasizes the long term fuel volumes and technologies, which is understandable because these volumes represent the full implementation of EISA. However, this approach does not adequately address the transition costs or risks. NREL's analysis of enzymatic hydrolysis predicts cellulosic ethanol plants costing $3.17/annual gallon in construction cost with a required selling price of $1.33/gal and a yield of 90 gal/ton as a 2012 target. Clearly this target will not be met with planned cellulosic ethanol plants announcing estimated construction cost over $6/annual gallon (Ethanol Producer Magazine August 2009).Even if the plants perform as predicted, the costs would be much higher in the short term than as indicated by the cost curve shown in the DRIA (pg 404). In addition, EPA does not adequately consider other technologies such as acid hydrolysis, which would consume other materials and result in different life cycle impacts.

EPA's approach has two key shortcomings. EPA does not consider the potential high costs of near term cellulosic ethanol plants. These costs should be reflected in a realistic assessment of the potential to build out the technology, the drain on other investment resources such as upgrading existing corn ethanol plants, and the competition from other candidate biofuels such as sugarcane ethanol. In addition, the capital and operating costs should feed into the economic analysis, which would predict relatively little ethanol sold if plant capital costs are $6/gal. The DRIA repeatedly attributes projections to FASOM (for example DRIA pg 283 ―we found that LUC changes are larger when food crops are used as biofuel feedstocks than when non food crops are converted to biofuel"). These projections are based on cost, crop yield, and biorefinery yield assumptions disguised as results. If cellulosic ethanol does not advance as projected, either the shortfall will have to be met by ethanol technologies at higher volumes or EPA will have to waive the volume requirements for cellulosic ethanol. Brazilian ethanol may end up as a high volume advanced biofuel. Furthermore, the mandates in EISA may generate sufficient price premiums to skew the economics of cellulosic feedstocks[1] and affect the land use impacts of cellulosic feedstocks.

---

[1] Consider a price premium of $0.20/gal, 100 gal/ton, and 5 tons/acre. This results in additional revenue of $100/acre.

2.1.2 Ethanol Production Pathways

EPA's calculation of the life cycle GHG emissions is based on the performance of fuel technologies described in the DRIA. Energy and material inputs provide the basis for the calculation of direct emissions. These inputs are summed over the fuel cycle and combined with comparable life cycle factors for diesel, electric power, fertilizer and other inputs. The GREET model performs most of these calculations internally and provides an adjustment for co-products. This approach is similar to the approach taken by the European Joint Research Centre (JRC) and Canadian GHGenius life cycle models (Edwards, et al. 2008, O'Conner 2005). The key factors that drive GHG emissions are energy inputs, fertilizer application, and treatment of co-products.

EPA calculates the GHG emissions for a range of corn ethanol technology options. The energy requirements for corn ethanol plants in the DRIA are consistent with surveys and process modeling. Thus disparities between the DRIA outputs and those of others - such as the GREET default, the California GREET, and the Biofuel Energy Systems Simulator (BESS) models - are almost entirely due to differences in inputs (Plevin 2009) driven by different scenarios for ethanol plant technology. For example ARB examines dry mill plants that are available today while EPA focuses on a projection of new technologies, which would need to be built or retrofitted in 10 years. This is a major contributor to differences between ARB and EPA estimates.

The aggregation of technology in the DRIA attributes the best corn ethanol plants to EISA requirements. In fact, there is considerable uncertainty here. Also, ethanol plants would be retrofitted to more efficient technologies such as oil extraction absent EISA as illustrated in Figure 2.1. EPA's analysis of 2022 technologies effectively cherry picks the best ethanol plant options and attributes these to EISA.

The objective of the DRIA is to examine the effect of the rule; however it does not provide clear guidance on the requirements for new corn ethanol plants to meet the 20% GHG reduction threshold. The energy inputs and performance for most dry mill ethanol plants is relatively simple. Dry mill plants primarily use natural gas and electric power as energy inputs (as well as small amounts of ammonia, urea, and other acids for sterilization and pH control. These inputs are not covered in the DRIA or GREET). A better approach would be to rate ethanol plants according to their performance and only categorize plants that fall within certain feedstock or energy use parameters as is the approach for ARB's LCFS (ARB 2008, ARB 2008b). EPA does examine the effect of different corn ethanol options (DRIA pg 407, Figure 2.8-4); however, the analysis is limited to projected technology options. An ethanol plant operator has no way of knowing the carbon footprint for his facility and the design requirement for a facility that is to be constructed to comply with EISA.

EPA also examines the GHG emissions from sugar cane and cellulosic ethanol. Again, the process energy requirements for ethanol production appear reasonable for ethanol processed in Brazil. Transportation logistics may be more complicated than indicated in GREET. The DRIA does not examine the potential for increased truck transport of ethanol in Brazil and the trend is toward increased pipeline transport. The DRIA does not mention dewatering in the Caribbean using fuel oil fueled steam, which is a significant source (37%) of Brazilian ethanol used in the

U.S. (Zuurbier 2008). Dewatering (dehydrating) ethanol requires about 1,900 Btu/gal (2 MJ/gal) and dewatering with fuel oil rather than bagasse fueled steam power adds at least 2 g GHG/MJ of ethanol[2].
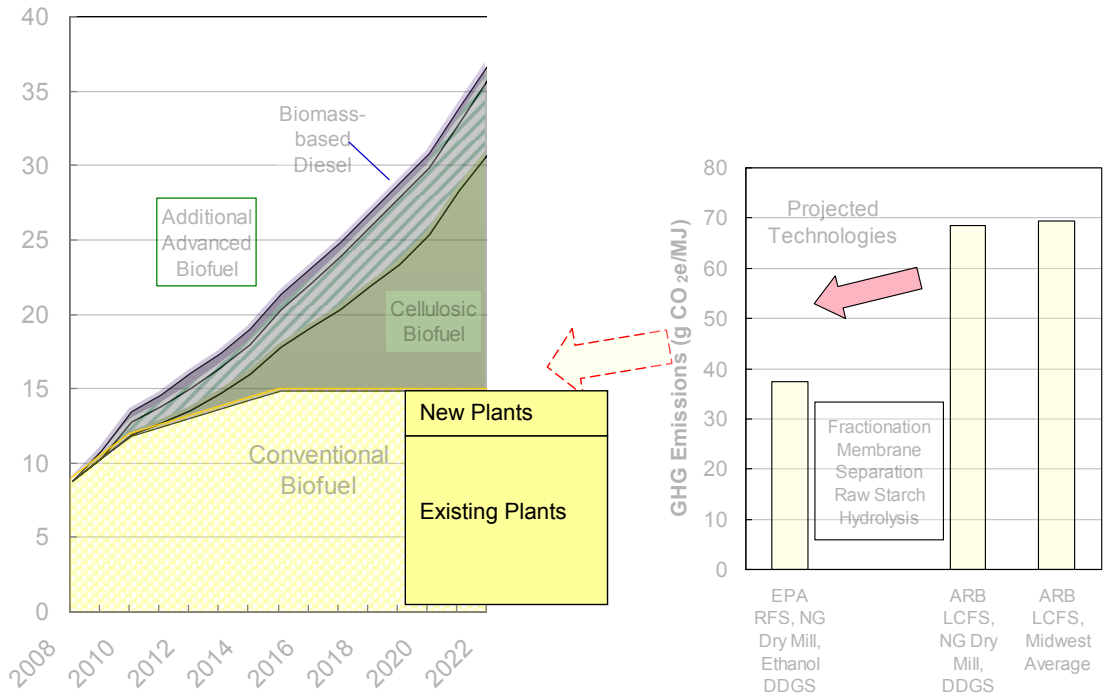
Figure 2.1 Volume requirement vs. year and the role of corn ethanol technologies.

The DRIA examines a number of cellulosic ethanol pathways. Enzymatic hydrolysis processes are examined in great detail. Other options including gasification, fermentation, acid hydrolysis, and others exist. EPA does not investigate the material inputs for these options or their life cycle GHG emissions.

2.1.3 Ethanol Energy Inputs and GHG Calculations

The DRIA calculates the energy inputs and GHG emissions from ethanol production using a combination of FASOM and FAPRI to determine agricultural inputs combined with GREET emission factors for direct emissions. The agricultural inputs are comparable to projections in GREET and are discussed further in Section 2.7. Nitrogen and N_2O impacts are examined in more detail in Section 2.6. It appears that EPA has underestimated the fuel cycle impacts of fertilizer production.

---

[2] (2 MJ/gal x 93 g GHG/MJ)/(80 MJ/gal ethanol)

2.1.3.1 Agricultural Inputs

Agricultural inputs include fuel for farm equipment, electricity for farm operations, and chemical inputs, including fertilizers, herbicides and insecticides. The National Agricultural Statistics Service (NASS) data show fertilizer application and yields by state (see Figure 2.2 below). As the statistics show, Iowa and Illinois produce the most corn, but all states show a very similar yield on a per acre basis and a modest range of nitrogen inputs on a per bushel basis. Nitrogen is the main fertilizer input for crop, wood, and algae production, but phosphate, potash, and lime are also important and represent a relatively tight range as well.
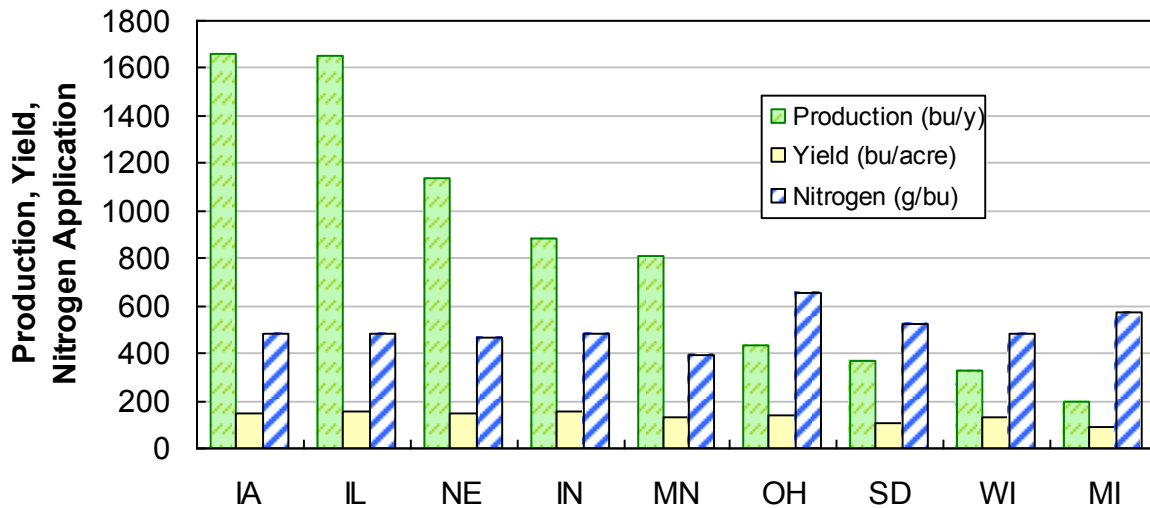
Figure 2.2 Corn annual production, bushels/acre and nitrogen application rate (USDA 2008)

The Food and Agricultural Organization (FAO) of the United Nations maintains fertilizer statistics by country for nitrogen, phosphorous, and potassium, known as FertiStat. Table 2.2 below shows the FAO fertilizer application data for key crops grown in the U.S. (1998) and Brazil (2002) in kg nutrient per hectare. FAO data represent chemical inputs on applied land; the GHG calculations should reflect GHG emissions per unit of harvested crop, which requires a yield factor indicating the crop yield (bushel or tons) per land area (acre or hectare). Although the FertiStat database does not include crop yield data along with the fertilizer application data, the FAO does have average crop yield data by country (Table 2.2), which can be used to convert the application yield data to units of gram chemical input per bushel or ton of crop produced, assuming the yield data is on an ―applied" basis rather than a harvested basis.

The nitrogen application rate used in the GREET model is shown below in Figure 2.3. The fertilizer input parameters are projections based on the USDA fertilizer data, and the nitrogen rate corresponds closely with the FAO data for the U.S. Fertilizer use rates decrease over time as farming management practices improve.

Table 2.2. FAO Fertilizer Inputs (FAO 1998 and 2002).

Nutrient	U.S. (1998)	Brazil (2002)	
Crop	Corn	Corn	Sugarcane
Application Rate (kg/ha)			
N	150.0	40.0	55.0
P	70.0	35.0	51.0
K	90.0	33.0	110.0
Crop Yield (kg/ha)	8,438	3,058	71,440
Application Rate	g/bu	g/bu	g/tonne
N	451.5	332.3	769.9
P	210.7	290.7	713.9
K	270.9	274.1	1,539.7
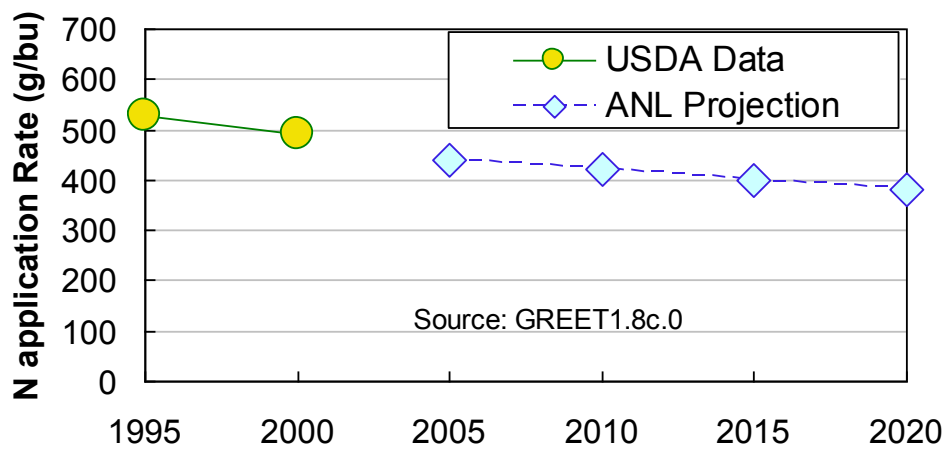
Figure 2.3. The GREET model corn farming nitrogen application rate

GREET counts the residual nitrogen, presumably from manure or crop rotation with soybeans, in the calculation of agricultural nitrous oxide (N_2O) emissions. GREET assumes that 1.3% of nitrogen applied becomes residual nitrogen and is converted to nitrous oxide.

2.1.3.2 Ethanol Plant Inputs

The energy input for dry mill corn ethanol plants ranges from approximately 30,000 to 42,000 Btu/gallon (anhydrous), based on the process fuel, process configuration, and combustion technology. Table 2.3 below shows the heat rates for corn ethanol technologies assumed under the Low Carbon Fuel Standard. Approximately 10,000 Btu/gal is required to dry DGS if the feed cannot be used wet locally. When the heat requirement is met primarily by natural gas or coal, the fuel plant receives a moderate carbon intensity score. Fuel plants that incorporate stover or

other biomass as process fuel achieve lower carbon intensity scores because the carbon in the biomass combusted is short cycle biogenic carbon and is considered climate neutral (0 g CO_2e/MJ). Only the biomass boiler (or gasifier) methane and nitrous oxide emissions count for biomass combusted as process fuel.

Ethanol plants, like most biofuel plants, consume chemicals including urea, ammonia, and small amounts of acids (sulfuric acid) and bases (sodium hydroxide). Chemical use for a dry mill corn ethanol plant is small per gallon (approximately 0.17 lbs of chemicals total per gallon ethanol) but results in thousands of tons of each chemical used per year for a full-scale facility (100 Mgpy). Sulfuric acid and sodium hydroxide are used to clean tanks, urea is a nutrient consumed during fermentation, and anhydrous ammonia is used in the early stages of the process for pH balance and to enhance the effectiveness of the enzymes used in the slurry system. Most life cycle analyses to date have completely excluded the chemicals used in ethanol plants from the life cycle assessment. The EPA assessment and the GREET model exclude these chemicals from the CI calculation, indicating that the fuel plant life cycle emissions is underestimated.

Table 2.3. Corn Ethanol Plant Heat Rates Used in the CA LCFS.

Type	Region	DGS	Heat Rate (Btu/gal)
Dry Mill	Midwest	Dry	32,330
Dry Mill	Midwest	Wet	22,430
Wet Mill	Midwest	-	45,950

2.1.4 Ethanol Co-Products

Ethanol production generates animal feed and/or electricity co-products. Credits for these co-products have a significant impact on the LCA of ethanol fuels with different attribution methods leading to quite different results for any given product or process.

2.1.4.1 Electric Power

Many of the ethanol pathways generate excess electricity through the combustion of biomass residue to meet onsite heat and electricity needs. In the DRIA and GREET model, excess electricity sold to the grid is assigned a greenhouse gas emission credit equal to the upstream emissions associated with the displaced grid electricity (the displacement method). EPA provides a credit for electric power for herbaceous biomass such as corn stover and bagasse from sugar cane ethanol production. The impacts of the co-product credits are shown in Table 2.4. GREET provides a full credit for displaced power, subject to transmission losses (8%), which is converted into an agriculture sector net power usage in FASOM.

A more appropriate treatment would be to consider the causality between the ethanol production and the credit, rather than simply assigning a credit to export power. The JRC has considered situations in transportation fuel LCAs to avoid assigning excessively large co-product credits that completely offset the well to tank emission results. In these cases, the export electricity is a

dominant product and treating it as a co-product is inappropriate and referred to as gearing. Providing a credit based on biomass power is more appropriate (Larivé 2008, Edwards 2008).

Table 2.4. Effect of Co-Product Electricity

Power Parameter	Corn Stover	Switch Grass	Sugar Cane
FASOM Net U.S. Electricity (kWh/1000 gal)	-0.02	-0.08	0
GREET 1.8c.0 Net Power (kWh/gal)	0	-0.57	-0.96
GREET 1.8c.0 GHG Credit (g CO_2e/MJ)	0	-4.9	-8.5
Appropriate Consequential LCA Credit (g CO_2e/MJ)	0	~0	~0

Another challenge with electricity co-product credits is the potential for double counting. Double counting emission benefits can arise in numerous situations and occurs when emission reduction credits are claimed under multiple programs or by multiple producers. Overlapping credits reduce the efficacy of environmental policies and should be considered in any consequential life cycle analysis. For example, some Brazilian sugar cane ethanol producers are aware of the challenge of avoiding double counting of emission credits (Leão de Sousa 2009).

2.1.4.2 Corn Ethanol Distillers Grains and Solubles (DGS)

Ethanol produced using the dry-milling process results in solid and liquid co-products—distillers grains and thin stillage—which are generally mixed together and sold as animal feed, most commonly after drying the mixture to produce *distillers dried grains and solubles* or DDGS. When local cattle ranching provides sufficient demand, the distillers grains may be sold wet (WDGS).

Most life cycle analyses assign a co-product credit based on the displacement of substitute products used as animal feed, including feed corn, silage corn, soybean meal, and others. The previous version of GREET (1.8b) used a DDGS yield factor and assumed DDGS displaced feed corn and soybean meal in equal parts in addition to a small amount of urea displacement. The current GREET model (1.8c.0) assumes the same DDGS yield but uses a wet DGS yield factor and assumes one to one (1:1) corn displacement, three to one (3:1) soybean meal displacement, and a small quantity of urea displacement. The ARB analysis to support the California LCFS assumes a direct one to one (1:1) displacement of feed corn by DDGS. This method decouples the corn ethanol and soybean-based fuel pathways and avoids the difficulty of using a displacement factor that equates DGS and soybean meal. The displacement method is straightforward to implement because life cycle data are available for many animal feeds, but it necessitates the use of a displacement factor indicating the quantity of product displaced by a unit of DGS. The displacement factor is based on one of several energy or nutrition metrics, including calorie content, protein content, vitamin/mineral profiles and others. Determining a displacement factors for similar feeds (feed corn and DGS or soybeans and soybean meal) is easier and more defensible than determining factors for different feed types (soybean meal and vinasse syrup).

The displacement factor inherently reflects market conditions by implying that the DGS is sold as animal feed and displaces a substitute product. As biofuel production increases over time, the production of animal feeds may saturate the market, eliminating the value of additional DGS as animal feed. Figure 2.4 shows corn ethanol production and approximate DDGS production in 2006 and projected for 2015 under the EISA. Annual corn ethanol production of 12 billion gallons would generate approximately 29 million tonnes of DDGS.

For comparison, current annual U.S. corn production is approximately 345 million tonnes. If the animal feed market uses all the solid residuals and the liquids produced (together or separately), the remaining DGS can be burned as an energy source instead.
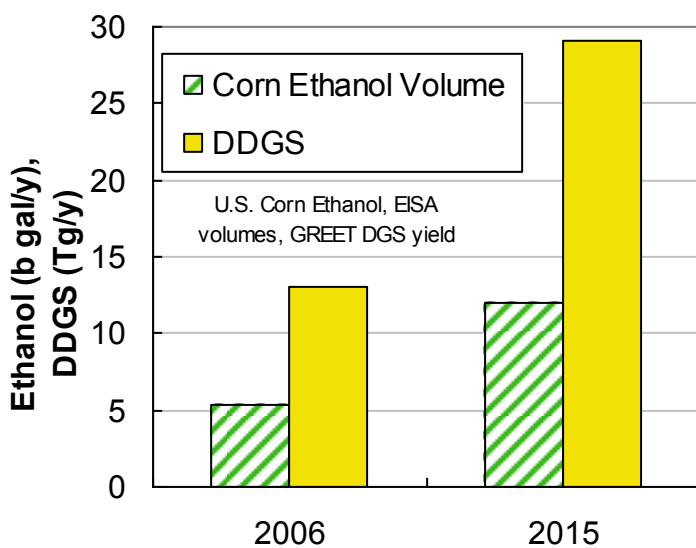
Figure 2.4. U.S. corn ethanol production and associated DDGS Yield for 2006 and 2015.

2.1.5 Key Findings and Recommendations

EPA should take several steps to represent a more accurate picture of the impact of ethanol fuels. First, the cost and viability of the near term transition to ethanol fuels is oversimplified. Secondly, the aggregation of technologies and analysis for 2022 technologies attributes improvements and co-product power that are not related to the rule. Finally, the GREET model should be updated to address numerous issues.

To determine the viability of the rule, EPA should examine more carefully the near term costs of cellulosic ethanol and the risks and contingencies associated with a build-up of new technology that is as rapid as the prior expansion in corn ethanol production. Alternative scenarios for sugar cane ethanol need to be examined, including sugar cane ethanol produced in Brazil and the U.S. under a range of production assumptions. For example, dewatering of ethanol in the Caribbean and more complex transport pathways should be examined.

EPA should rate ethanol plants on actual performance and develop ratings for ethanol plants that fall into technology categories similar to the approach taken by ARB (ARB 2008b). The attribution of corn ethanol technology should be more carefully examined, and alternative scenarios for corn ethanol should assume a more realistic mix of technologies.

Life cycle calculations and the GREET model should be updated to address a number of data input and calculation issues. Analyses should be careful and conservative about assigning co-product credits and avoid granting displacement-based credits unjustified by current market conditions or excessively large co-product electricity credits. Co-product power should not be assigned to excess biomass residue that is not related to the ethanol production process (Larivé 2008). EPA should also consider in its consequential LCA the likelihood that any biomass power will be sold to meet a renewable obligation and double crediting should be eliminated (ARB 2008b).

Finally, life cycle accounting of corn ethanol and other biofuels should be expanded to include the life cycle energy and emissions associated with chemicals used in fuel plant associated fermentation or other conversion process. The EPA assessment omits the nutrients, acids, and bases consumed during biofuel production, and counts only the natural gas, coal, and electricity consumed. Therefore, comparing the carbon intensities for biofuel pathways or even fuel cycle emissions for the ethanol plant alone gives no indication of the chemical requirements for fuel conversion. Many of the chemicals used are very energy intensive to make and are derived from a fossil feedstock, such as natural gas, petroleum, or coal. Omitting these chemicals and their upstream impacts is incorrect and they should be explicitly added to the EPA analysis, especially because most or all of the chemicals are already represented in GREET. Assessments of biofuel pathways using chemicals not included in GREET should include calculations based on LCI data from other sources.

2.2   Biodiesel Pathways

Although sometimes used generically to refer to biomass-based diesel substitutes, the term *biodiesel* technically refers only to fatty-acid methyl esters (FAME). Other diesel substitutes are grouped together under the term *non-ester renewable diesel*. Pressing oil from feedstock crops often produces salable protein co-products used as animal feed. In addition, oil conversion processes yield various co-products.

Biodiesel is produced by reacting fat or oil feedstocks (the most common is soybean oil) with acid or base and methanol (or ethanol) in a transesterification reaction to produce a methyl or ethyl ester and glycerin[3]. In general, oil extraction from oil seeds and transesterification are the most energy intensive steps in the fuel pathway, and crop cultivation is comparatively less intensive. Waste oils and fats can also be collected and converted to diesel substitutes. Glycerin is produced during the transesterification of triglycerides to yield biodiesel and can be sold in crude form, or distilled to 99% or higher purity for sale to the cosmetic and pharmaceutical

---

[3] National Biodiesel Board. (2007, April 26, 2007). "Biodiesel Production and Quality."   Retrieved November 3, 2007, from http://www.biodiesel.org/pdf_files/fuelfactsheets/prod_quality.pdf..

industries as refined glycerin. Hydrotreated bio-oils produce renewable diesel, composed of long alkyl chains comparable to petroleum diesel. This process produces propane as a co-product that can be used internally as a process fuel or sold.

2.2.1 Biodiesel Feedstocks

Soybean cultivation for fuel production includes farming input energy (crop harvesting), fertilizer, herbicide, and pesticide inputs and soybean transport. GREET models each of these steps, and the main inputs that drive the feedstock calculations are energy and chemical inputs on a per bushel basis for feedstock and fuel production, and the agricultural inputs (fertilizer, herbicide and pesticide).

2.2.1.1 GREET Soybean Inputs

The agricultural inputs from GREET 1.8a are shown below in Table 2.5 for target year 2010. These inputs are presumably based on the 1998 publication by Sheehan et al., which were based on 14 Midwest states in 1990 (Sheehan, et al. 1998). GREET 1.5 used the Sheehan input values after reducing them all 10% to approximate 2005 values (Wang 1999). GREET 1.8c.0 uses the same herbicide and pesticide inputs for 2005 as GREET 1.5a, but the fertilizer inputs for 2005 (and all subsequent years) have been reduced by approximately 50%; the farming energy input in GREET 1.8c.0 is 22,087 Btu/bushel for all years (1990-2020), which is 31% less than the 2005 value in GREET 1.5. The data source to support these input reductions is unknown. The inputs shown in Table 2.5 remain the same from 2010-2020 in GREET 1.8c.0. This means that the agriculture component of the biodiesel well-to-tank results change very little from 2010-2020 (< 0.4%).

Table 2.5. Farming Energy, Fertilizer, Herbicide, Pesticide and Oil Extraction Energy Inputs in GREET for Target Year 2010 and from Other Studies.

Source	Farming Energy	N	P_2O_5	K_2O	Herbicide	Pesticide
	Btu/bushel			g/bu		
GREET 1.8c.0 (Wang 2007)	22,087	61.2	186.1	325.5	43.02	0.43
Hill et al. (2006)	32,603	58.3	175.9	307.8	-	12.27
Pimentel et al. (2005)	30,987	37.7	385.6	151.0	13.26	-
Unnasch and Pont (2007)	28,926	107.1	335.7	571.5	43.02	0.43
Sheehan, et al. (1998)	35,710	132.1	414.2	705.0	53.10	0.53
USDA statistics (2007)		176.2	506.4	880.8	14.64	2.52

Soybean farming inputs from three recent studies (Hill, et al., Pimentel, et al. 2005, and Unnasch et al. 2007) are shown in Table 2.5. The Sheehan et al. (1998) publication and USDA statistics for 2006 are also shown in the table. The farm input energy from Hill et al. 2006 and Pimentel et al. 2005 vary little (Sheehan's input energy is higher because they model 1990 farming), but the fertilizer, herbicide, pesticide and fuel production energy inputs vary significantly (by a factor of 2-3) across these studies. Much of the variation in the farming phase is likely due to natural

variation in environmental factors and farm practices; the USDA farm input statistics show significant variation at the state level for soybean cultivation inputs.

Soybean yields have grown an average of 30-45% between 1972 and 2003 in the Midwestern U.S., and yield growth is likely to continue well into the future (Egli 2008). Most of this improvement is due to cultivar (crop varieties selected for advantageous attributes) and farm management improvements. Farm management improvements since 1972 include narrower rows, improved weed control, earlier planting, conservation tilling and reductions in harvest losses (Johnson, 1987; Heatherly and Elmore 2004).

2.2.1.2 Agricultural Inputs

The GREET default fertilizer inputs are well below the U.S. averages, although these lower input levels are being achieved in certain soybean fields (USDA 2007). The farming energy input is likely low, and may be appropriate for a future target year. Wang assumed a 0.7% annual decrease in farm inputs from 1990 to 2005 (15 years). Using the average farm energy input (31,795 Btu/bu) from Pimentel et al. (2005) and Hill et al. (2006) for 2005, and decreasing this value by 0.7% yields 30,750 Btu/bu in 2010 and 29,350 Btu/bu in 2017 (see Table 2.6).

Applying a 0.7%/yr reduction in chemical inputs yields the input values shown in Table 2.6. Given the data available and established yield trends these values seem reasonable. The default fuel production energy inputs (soy oil extraction and oil transesterification) in GREET are high relative to the recent estimates, but within reason.

Table 2.6. Recommended Soybean Farming Inputs for Target Years 2010 and 2017 Based on USDA Average Chemical Inputs for 2006 and Farming Energy Input. (Hill et al. 2006 and Pimentel et al. 2005)

Target Year	Farming Energy Btu/bushel	N	P_2O_5	K_2O	Herbicide	Pesticide
				g/bu		
2010	30,750	172	493	858	14	2
2017	29,350	164	471	818	14	2

Table 2.7 below shows the g/bushel GHG emission results for soybean cultivation, based on the primary energy and chemical inputs shown in Table 2.6. The harvesting emissions are based on the lifecycle emission results for the diesel, gasoline, natural gas, LPG, and electricity necessary for crop collection. The emissions for chemical inputs are based on the life cycle emissions for each chemical product. The soybean transport emissions are based on truck transport calculations in the T&D sheet of GREET. Section 2.6 describes the soil N_2O emissions in detail.

Table 2.7. Agriculture Phase Greenhouse Gas Emissions in g/bushel for 2010 Calculated in GREET 1.8c.0

GHG Species	Harvesting	Nitrogen	Phosphate	Potash	Herbicide	Pesticide	Soil Emissions	Soybean Transport	Total
VOC	2.392	1.044	0.182	0.103	0.037	0.007		0.212	3.977
CO	11.367	0.983	0.622	0.367	0.137	0.029		0.848	14.353
CH$_4$	4.475	0.496	0.87	0.827	0.432	0.07		0.57	7.741
N$_2$O	0.052	0.281	0.009	0.008	0.003	0.001	7,760	0.013	8.127
CO$_2$	2,838	417	482	559	298	48		501	5,145
GHG	2,991	518	508	583	310	50	2,313	521	7,795

2.2.2 Biodiesel Production

In producing biodiesel, oil is first produced by pressing soybeans or other oil producing crops and using solvents (usually n-hexane). This step is calculated in GREET based on the energy input (5,867 Btu/lb oil) for soy oil extraction, which is allocated between natural gas (87.5%), electricity (9.4%) and n-hexane (3.1%). The GREET transesterification energy input of 2,116 Btu/lb biodiesel is allocated between natural gas (42.0%), electricity (2.2%), methanol (40.9%), sodium hydroxide (2.0%), sodium methoxide (9.9%) and hydrochloric acid (3.0%). Although GREET models oil extraction and transesterification separately, these calculations are not used when the model is set to energy allocation for co-product credits. Instead, GREET uses weighted average energy input and fuel shares based on oil extraction and transesterification inputs, and applies an allocation factor based on the energy share of biodiesel, soybean meal, and glycerin product streams. This method could be considered flawed because it credits the transesterification process for soybean meal production, yielding net fuel cycle emissions that are artificially too low. GREET includes the energy associated with the chemicals used in biodiesel production, but omits the upstream emissions associated with the producing the chemicals (similar to the treatment of ethanol, except ethanol excludes the energy content of the chemicals).

2.2.2.1 Soybean Biodiesel GREET Inputs

Table 2.8 shows the GREET biodiesel production energy input values and values reported from the same sources referenced in the soybean feedstock section, including the EUCAR/ CONCAWE study (Sheehan, et al. 1998; Pimentel and Patzek 2005; Hill, et al. 2006; CONCAWE 2007; Unnasch and Pont 2007; and Wang, 2007). GREET calculates oil transesterification emissions based on Btu/lb soy diesel (in parenthesis) and the input is shown here in Btu/lb soy oil for comparison with other estimates.

To facilitate comparison among studies, Table 2.8 includes only steam (NG) and electricity energy for soy oil extraction and steam (NG), electricity and methanol (LHV, not primary energy). Energy related to chemical input (n-hexane, sodium hydroxide, sodium methoxide and hydrochloric acid) are excluded in the table but included in GREET calculations.

Table 2.8. Soy Oil Extraction Energy and Oil Transesterification Energy Inputs Used in GREET Reported in Other Studies (Sheehan, et al. 1998; Pimentel and Patzek 2005; Hill, et al 2006; CONCAWE 2007; Unnasch and Pont 2007; Wang 2007).

Source	Soy Oil Extraction[1]	Oil Transesterification [2]
	Btu/lb oil (Btu/lb soy diesel)	
GREET 1.8c.0	5,685	1,731 (1,801)
Hill et al. (2006)	1,794	(1,344)
Pimentel and Patzek (2005)	4,523[3]	
Unnasch and Pont (2007)	5,685	1,487 (1,546)
Sheehan (NREL) (1998)	6,380	2,681
EUCAR/CONCAWE (2006)		(1,649)

[1]Soy oil extraction energy includes only NG for steam and electricity.

[2]Oil transesterification energy includes only NG for steam, electricity and methanol (LHV, not primary inputs).

[3]Pimentel and Patzek gives the combined extraction and transesterification energy inputs.

The default GREET fuel production energy is within the range of the other estimates but may be too high. The soy oil extraction energy estimated by Hill et al. is less than half of the GREET input, and the total biodiesel production energy (soy oil extraction and oil transesterification) estimated by Pimentel et al. is significantly lower than the GREET value for soy oil extraction alone. The GREET energy inputs remain essentially the same between 2010 and 2017; the transesterification energy inputs are hardwired in GREET and don't change, and the soy oil extraction energy decreases from 5,867 to 5,800 Btu/lb oil (including all inputs) in 2015 and remains the same until 2020.

2.2.2.2 Soybean Biodiesel GREET Calculations

The soy diesel production emission results are first calculated in the same denominator units as the direct energy inputs, g/lb oil and g/lb soy diesel, for oil extraction and transesterification, respectively (see Table 2.9). These intermediate results use a U.S. electricity mix.

Table 2.9. GREET Intermediate Emission Results (Unallocated) for Soy Oil Extraction and Oil Transesterification in 2010.

Emission Species	Soy Oil Extraction	Oil Transesterification
	g/lb soy oil	g/lb soy diesel
CH_4	1.190	0.346
N_2O	0.008	0.002
CO_2	451	90
GHGs	499	99

Table 2.10 shows the well-to-tank (WTT) emission results for feedstock and fuel production in 2010 and 2017. GREET allocates 33.8% of soybean farming, transport, and soy oil extraction

energy and emissions, and 32.1% of the transesterification energy and emissions to WTT feedstock and fuel results. As the results show, GREET estimates a very small change in GHG emissions between 2010 and 2017 (< 2% reduction).

Table 2.10. GREET 1.8c. WTT Emission Results for Biodiesel in 2010 and 2017

Emission Species	2010		2017	
	Feedstock	Fuel	Feedstock	Fuel
	g/mmBtu	g/mmBtu	g/mmBtu	g/mmBtu
CH_4	11.14	32.23	11.11	31.70
N_2O	10.53	0.21	10.53	0.21
CO_2	7,556	12,120	7,550	11,861
GHGs	10,973	12,988	10,967	12,716

2.2.2.3 Results from Other Studies

TIAX, LLC reviewed GREET 1.7 (Pont 2007) and made several input modifications to parameterize the model according to California-specific data. The emission factors for the CA GREET version correspond to California standards and transportation distances reflect the marginal delivery of fuels to California. The heating values of several fuels were corrected, including Fischer-Tropsch diesel (FTD), reformulated diesel, natural gas, and hydrogen. The biodiesel WTT results corresponding to a U.S. electricity mix are shown below in Table 2.11 for target years 2010 and 2017. As the results show, the WTT greenhouse gas emissions estimated by the CA GREET are significantly higher than calculated by GREET 1.8c.0. There are several reasons for this. TIAX assumed higher farming energy and chemical inputs and allocated a larger share of feedstock production energy and emissions to biodiesel. For fuel production, the CA GREET assumed a lower thermal energy input and higher methanol input than GREET1.8c.0 and the CA GREET allocated a higher share of oil extraction and oil transesterification emissions to fuel production.

Table 2.11. CA GREET WTT Emission Results for Biodiesel in 2010 and 2017

Emission Species	2010		2017	
	Feedstock	Fuel	Feedstock	Fuel
	g/mmBtu	g/mmBtu	g/mmBtu	g/mmBtu
CH_4	18.84	44.06	18.22	43.35
N_2O	7.34	0.15	7.34	0.15
CO_2	15,679	19,749	15,401	19,276
GHGs	18,338	20,895	18,043	20,405

The two models have different allocation factors for fuel and co-products and apply the factors differently. GREET1.7 is based on the market value co-product method while the default method in GREET1.8c.0 is energy allocation. CA GREET correctly treats oil extraction and

transesterification separately and applies different allocation factors to each. However, GREET1.8c.0 uses a weighted average representation of oil extraction and transesterification and applies one allocation factor to the results. As discussed above, the weighted average fuel production approach in GREET1.8c.0 over-credits the soybean meal and glycerin from oil extraction and transesterification.

2.2.3. Biodiesel Co-Products

The documentation for GREET 1.5 indicates that the market value approach is used to allocate inputs and emissions from the production of soybeans between soy oil and soybean meal, and from the transesterification process between biodiesel and glycerin (Wang 1999, p. 83-85).

The 1999 GREET documentation also provides the percent allocation between co-products based on the displacement method. In the case of glycerin, the alternative production method is assumed to be petroleum-based. Soybean meal is assumed to displace barley.

GREET 1.8c.0 includes displacement energy and market value allocation methods for biodiesel co-products. Displacement is based on soybean meal displacing soybeans (1.2 lb/lb soybean meal) and glycerin displacing petro-glycerin. It's unclear whether these are good measures of the avoided impacts, since (a) the crude glycerin market is flooded, so there may be no displacement associated with additional glycerin production, (b) soybean meal likely displaces other protein products in addition to soybeans and barley. These issues demonstrate why a market equilibrium analysis is the theoretically correct approach to handling co-products, although performing such an analysis can be fairly complicated in practice.

The GREET1.8c.0 co-product credits for soy biodiesel based on the energy allocation (default) and mass-based displacement methods are shown in Table 2.12. The energy allocation method yields large co-product credits because soy oil extraction produces significant quantities of soybean meal, and the meal is included in the allocation factor applied to fuel production (including oil extraction and transesterification). The displacement method yields even larger co-product credits because of the favorable soybean/soybean meal displacement factor and displacement of petro-glycerin. The displacement method usually yields the largest co-product credits for biofuel production and the approach is especially favorable to biodiesel. GREET assumes a pound of soybean meal displaces more than a pound of soybeans (1.2:1) on the basis of the protein content of each feed. However, calorie, vitamin, and amino acid content are also important and a more conservative approach is to credit the soybean meal for 1:1 displacement on a mass basis. The bio-glycerin co-product is almost certainly sold in a bio-glycerin dominant crude glycerin market and cannot be reasonably credited as displacing petroleum-based glycerin.

2.3   Non-Ester Renewable Diesel

Vegetable oils and animal fats can be processed into stable diesel products through methods other than esterification with alcohols. A leading method involves the processing of the oils with hydrogen to produce long chain saturated hydrocarbons. With this approach, propane is released from the triglyceride molecule. Hydrogen processing can be applied to the same oils used for

biodiesel production. The agricultural co-products produced during oil extraction are the same for non-ester and FAME pathways.

Table 2.12. Soy Biodiesel Co-Product Results

Energy Allocation Method

Process	Co-product	Energy Allocation Share to Co-Product	Energy Allocation Emissions Credit (g/MJ)
Soybean farming and transport	Soybean meal	66.2%	-23.6
Soy oil extraction and transesterification	Soybean meal and glycerin	62.1%	-24.7
		Total	-48.3

Displacement Method

Displaced product	Co-Product	Displacement Factor (lb/lb)	Energy Allocation Emissions Credit (g/MJ)
Soybeans	Soybean meal	1.2	-32.1
Petro glycerin	Glycerin	1	-34.6
		Total	**-66.7**

2.4 Synthetic Fuels

Various fuels can be produced through the thermo-chemical conversion of synthesis gas. Examples of leading pathways are shown in Table 2.13. All of these pathways have the potential to generate excess heat that can be used to generate steam or electricity. The most significant examples are hydrogen production in an oil refinery or hydrogen plant. The waste heat from the reforming process produces a significant quantity of steam, which can be used by oil refineries. The energy balance is closer to neutral for some large scale gas to liquid (GTL) facilities. Large-scale GTL plants in remote locations are configured to produce no steam or electricity. However, other GTL technologies may produce excess steam or electricity.

The production of GTL or synthetic diesel also results in co-product hydrocarbon streams, the most common of which is naphtha. The reaction can also produce lighter hydrocarbons and waxes.

2.5 Biofuel Energy Co-Products

Many pathways in GREET are configured to take a credit for co-produced electric power. These include cellulosic conversion of biomass to ethanol as well as a variety of Fischer-Tropsch Diesel (FTD) fuels from various feedstocks. The credit for electric power is applied using the displacement method, subject to a transmission and distribution loss.

Table 2.13. Synthetic Fuels and Co-Products

Fuel	Feedstock	Co-products
Methanol	Biomass	Electricity
Methanol	Coal	Electricity
Methanol	Natural Gas	Electricity
DME	Biomass	Electricity
DME	Coal	Electricity
DME	Natural Gas	Electricity
XTL	Biomass	Naphtha, electricity
XTL	Coal	Naphtha, electricity
GTL	Natural Gas	Naphtha, LPG

2.5.1 GREET Calculations of Electricity Credit

The credit for co-product electric power is based on the same generation mix used in the GREET modeling run except for sugar cane ethanol. For example, if the user selects a U.S. average generation mix for the model run, then co-produced electricity displaces U.S. average electricity. The uniform use of one electric power mix for most stationary applications (not including transportation electricity or hydrogen) must be well understood by model users. An exception to this method is the treatment of cogenerated electricity from Brazilian ethanol plants where the power clearly does not displace the U.S. mix. In this case, co-product biomass-based power is credited with the 100% natural gas-based Brazilian marginal generation mix.

Other applications of the GREET model have used a marginal electricity generation mix for both fuel production processes and cogenerated power, most notably California initiatives including the LCFS, the State Alternative Fuels Plan required under AB1007 (Pont 2007), and the California Hydrogen Highway Blueprint Plan (CalEPA 2005). An evaluation of the appropriate generation mix was conducted in both of these studies with the conclusion that the appropriate marginal power was best reflected by a mix of fossil generation combined with the constraint of the renewable portfolio standard (RPS). The RPS requires a growth of qualified new renewable resources in the California generation mix to 33% by the year 2020.

Other studies have also examined the use of an average power generation mix including imports. Historically, the average generation mix has not been representative of marginal electricity use for new fuels, especially when electric transportation is considered. The additional use of electric power will not result in the growth of hydroelectric or nuclear power sources, which are a large portion of the California average power generation.

2.5.2 Sugarcane and Cellulosic Ethanol

GREET 1.8c.0 allows the user to select the type of electricity displaced by co-product electricity exported from sugar cane and cellulosic ethanol facilities. By default, the selected electricity

grid is used. The user can alternatively select natural gas combined-cycle (NGCC) electricity, or biomass integrated gasification combined-cycle (IGCC) electricity as the electricity displaced.

For sugar cane, GREET 1.8c.0 allows the user to select the Brazilian or U.S. electricity grid. If Brazil is chosen, exported electricity is assumed to offset electricity produced using natural gas. The user can also input a custom mix to represent the marginal generation in Brazil.

2.5.3 Synthetic Fuels

GREET also allows for a credit for excess thermal energy where the use of the process energy might vary among applications. In the cases for hydrogen, methanol, dimethyl ether (DME), and FTD production, the user can input a steam credit. GREET then provides a credit based on the energy that would be needed to produce the same amount of steam from natural gas. This approach is a simplified version of the displacement method with natural gas-derived steam serving as a universal substitute product.

2.6 N_2O Emissions from Agriculture

Agricultural N_2O emissions result from conversion of fixed[4] (natural and anthropogenic) nitrogen in the soil. The introduction of nitrogen includes fertilizer, manure, and residue application as well as natural processes, including dry and wet deposition. Nitrogen species including nitrates, ammonia, and other compounds are nitrified or denitrified in soils into N_2O, a potent long-lived GHG. N_2O has a recently updated global warming potential (GWP) of 298 and soil N_2O emissions remain one of the most important and poorly characterized GHG sources to date (IPCC 2007).

Fixed nitrogen applied to field crops is either extracted by the crop as a nutrient, absorbed (chemically bound) into organic soil components or entrapped in soil aggregates (chemically unbound). Most of the chemically bound nitrogen remains stabilized in the organic form in the soil system, while the unbound nitrogen is converted to N_2O, volatilized as ammonia or other gases originating from soil nitrates, or leached out as nitrate. Indirect N_2O emissions result when the N in the system is volatilized or leached away in run-off. Volatilized N can redeposit somewhere else and be converted to N_2O, or the leached nitrate can be nitrified/denitrified to N_2O during run-off (Wagner-Riddel, et al. 2008). GREET seeks to model direct soil N_2O emissions and downstream emissions from leached nitrate.

Fertilizer is the dominant source of soil N_2O emissions and many studies have modeled the variables affecting N_2O emissions (Bouwman, et al. 2002; Stehfest.and Bouwman 2006). These factors include fertilizer application rates, crop type, tillage practices, soil characteristics (pH, organic C content, texture) and climate type. For example, a Canadian study concluded that no-till cropping more than doubled N_2O emissions compared to conventional till in heavy clay soils. However, no difference in N_2O emissions was observed when comparing the two cropping practices in a loam soil (Rochette, et al., 2008). Estimates of fixed N input to N_2O emissions

---

[4] In contrast to gaseous, diatomic nitrogen (N_2).

range from 3-5% on a global basis[5], and 1-2% or more for direct field emissions (Crutzen, et al. 2007). The primary difference between the global and field conversion rate is ―background" N_2O emissions occurring in rivers, estuaries and coastal zones, after the input N has leached out of the fields. The nitrogen content in crops is also highly dependent on the quantity, type, and timing of the fertilizer-N applied. The default GREET 1.8a input for N conversion to N_2O is 1.3%, including both direct emissions and downstream emissions (Wang 1999).

Nitrogen fertilizer life cycle emissions calculations are discussed in Section 2.6.1. EPA uses GREET to supply direct N_2O emissions that are combined with FASOM-based estimates of fertilizer use and land use change (LUC) impacts to determine the GHG emissions associated with agricultural operations presented in the DRIA. The GREET N_2O inputs are discussed below in Section 2.6.2 and the GREET calculations are outlined in Section 2.6.3. Section 2.6.4 discusses other N_2O studies, followed by a discussion of the uncertainties in N_2O emissions estimates in Section 2.6.5. N_2O emissions depend on the available nitrogen, soil conditions, moisture, and other parameters that affect the chemical and biological conversion of nitrogen species. All on the inputs are uncertain. The accuracy of EPA's analysis is difficult to assess because the inputs into FASOM and related DAYCENT analysis are not easily identified and are calculated on a regional basis. Emission factors applied to nitrogen application such as those used for GREET or FAPRI data are more readily documented.

An important uncertainty in the analysis may be the nitrogen application rate associated with international agriculture. Section 2.6.4 of the DRIA covers the nitrogen use for international activities and raises several issues. The data relies on the FertiStat database and no attempt is made to assess the soundness of this data or compare it with FASOM results for the U.S. The FAO web site appears to be more of an inventory estimation tool than a bottom up calculation of fertilizer use. Fertilizer application rates appear to be inputs (in round numbers) and total application is the product of hectares planted as estimated application rate. Figure 2.5 compares U.S. fertilizer application rates from USDA with Brazilian and Canadian application rates.

2.6.1 Nitrogen Fertilizer Life Cycle Estimates

Several important issues need highlighting regarding the treatment of fertilizers and other agricultural chemicals in life cycle analyses, especially those utilizing GREET. This section explores the production of ammonia and urea, and its subsequent impact on U.S. corn and Brazilian sugar cane ethanol fuel cycle emissions, illustrating the need to review input assumptions for agricultural chemical production. Production and life cycle analysis of nitric acid, ammonium nitrate, phosphate, potash, and lime are not examined here, but many of the same fundamental issues discussed in this section apply to these products as well. This section is organized in the following subsections:

    2.6.1.1   Nitrogen Fertilizer Production and Trends
    2.6.1.2   Agricultural Chemicals in Life Cycle Analysis and GREET

---

[5] This rate includes all of the reaction and decomposition pathways that yield N_2O, including downstream conversion of dissolved N species (nitrates and ammonia) in aquatic systems.

2.6.1.3   Life Cycle Greenhouse Gas Emissions Results
- U.S. Corn Ethanol
- Brazilian Sugarcane Ethanol

2.6.1.4   Issues and Recommendations
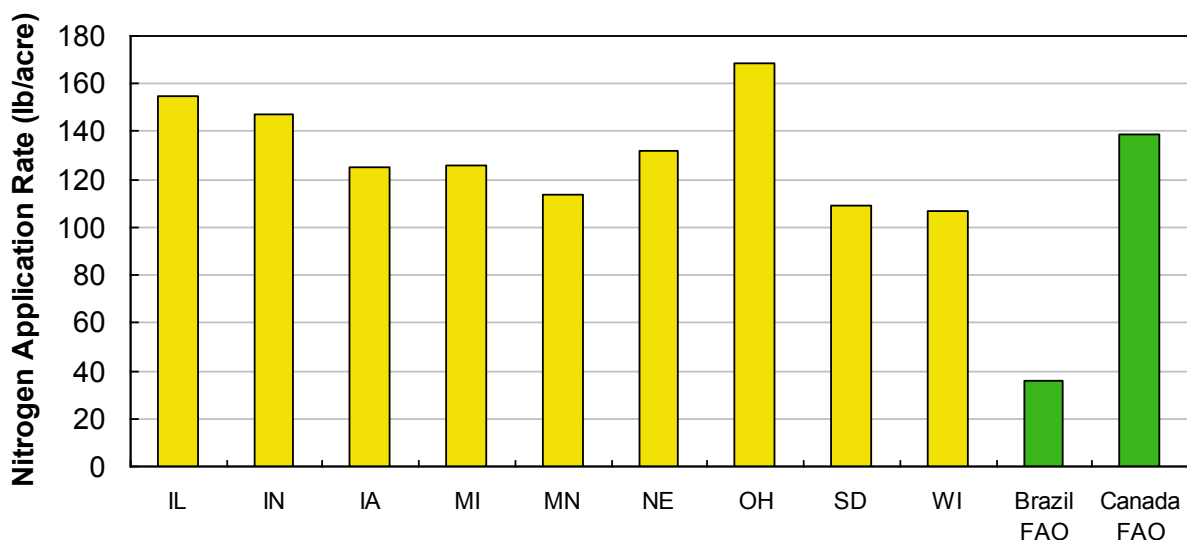
Figure 2.5. U.S. and select international nitrogen application rates. Source: USDA and www.fao.org/ag/agl/fertistat/

2.6.1.1 Nitrogen Fertilizer Production and Trends

Most nitrogen fertilizers are produced from ammonia (NH_3), and ammonia can be produced from many hydrocarbon feedstocks, including natural gas (NG) and coal. Most ammonia manufacturing uses hydrogen produced from a hydrocarbon feedstock (using reformation or gasification) reacted with atmospheric nitrogen (N_2) in the Haber-Bosch process. NG has the highest hydrogen content of any hydrocarbon, thereby yielding the lowest carbon emissions per unit of ammonia produced. When ammonia is produced from NG, one third (~33%) of the process emissions are derived from NG process fuel; the remaining emissions (~67%) are associated with hydrogen production. The emission proportions from coal-based ammonia production are 25% process fuel and 75% hydrogen production. Ammonia derived from natural gas requires 24-26 mmBtu NG/ton ammonia and ammonia derived from coal requires approximately 36–42 mmBtu/ton ammonia, 1.5 – 1.7 times as much energy as ammonia derived from natural gas (DOE 2006; Prince 2007).

Global ammonia production has increased more than 100-fold in the last 5 decades and now constitutes more than half of global nitrogenous fertilizer usage (USGS, 2008). Historically, ammonia was produced from NG because NG was inexpensive and international NG sources had few liquefied natural gas (LNG) terminals available to receive LNG tanker ships. In the early 2000's natural gas prices more than doubled to over $8/mmBtu currently (although prices have

declined to the $6 to $7/mmBtu range currently) (DOE 2010). Thus, more LNG terminals were built to accommodate LNG commerce, creating international competition for NG as a fertilizer feedstock. Coal is inexpensive and abundant and coal-based ammonia has steadily supplanted decreased natural gas production over the last decade. China is responsible for the almost all (97%) coal-based ammonia production and its production increased the global share of coal-based ammonia production by 4.4% from 2000 to 2007 (IFA, 2009). Coal-based ammonia currently accounts for more than 27% of total ammonia consumption globally; most of the balance is natural gas-based ammonia.

Ammonia statistics from the International Fertilizer Association (IFA) include ammonia[a] used to make urea, which is a different ammonia stream from the ammonia used directly as fertilizer or other purposes. U.S. imports of solid urea reached 6.1 million tons in 2008, and urea imported from China represented 12.8% of these imports (USDA, 2009). Domestic production of nitrogen fertilizers has decreased in recent years due to high natural gas prices and currently represents approximately 52% of U.S. nitrogen fertilizer use. China produces nearly all of the coal-based urea worldwide; approximately 70.2% of ammonia produced in China is coal-based and the rest is primarily derived from natural gas. Table 2.14 below shows the mix of solid urea fertilizer used in the U.S. in 2008. The current domestic and imported urea shares are 66.5% and 33.5%, respectively. The U.S. urea coal share estimates in Table 2.14 are based on the IFA fuel mix shares for global ammonia production (IFA 2009). Assuming that the IFA statistics on ammonia fuel mix reflect urea production as well and that the Chinese production mix reflects Chinese urea imported to the U.S., approximately 6.7% of urea consumed in the U.S. is derived from coal.

Table 2.14. Dry Solid Urea U.S. Consumption in 2008

Source	Urea (Million Tons)	Total Share[a]	Coal Share[b]
Urea Imported from China	0.8	8.5%	6.0%
Imports from Rest of World	5.4	58.0%	0.7%
U.S. Urea		-	-
Production	3.4	-	-
Exports	0.3	-	-
Net Domestic Urea	3.1	33.5%	0.0%
Total Apparent Consumption (Imports + Net Domestic)	9.2	100.0%	6.7%

[a]USDA (2009)
[b]IFA (2009)

2.6.1.2 Agricultural Chemicals in Life Cycle Analysis and GREET

Most life cycle analysis models, including GREET, cannot accurately represent average U.S. fertilizer use, because fertilizer used in the U.S. includes a mix of domestic and international chemicals produced using different feedstocks and production pathways. In GREET, chemical products are assumed to use natural gas as the feedstock. GREET is not properly configured to model coal based ammonia production; the emission calculations assume a coal-fired boiler

configuration (to generate steam for reformation) instead of gasification and omit the CO_2 emissions from coal feedstock. Urea production also assumes a coal-fired boiler and uses the upstream results from the ammonia calculations, rather than treating ammonia separately as an intermediate product and as fertilizer. Fertilizer emission results strongly influence biofuel life cycle results, thus, fertilizer analyses for U.S. crop production should reflect U.S. average parameters as accurately as possible.

In addition to the difficulty in incorporating the U.S. average fertilizer emissions into biofuel life cycle analyses, the ammonia production emissions calculations contain an error that undercounts emissions. The model differentiates between NG used as feedstock (71.7%) and NG used as process fuel (28.3%), and it applies emission factors and upstream NG emissions to the 28.3% NG process fuel input. However, the model only counts the carbon in the 71.7% NG feedstock input and mistakenly omits the upstream natural gas production emissions associated with the feedstock. This omission causes the life cycle GHG emission result for all nitrogen fertilizers to be too low. Correcting the calculations to include upstream NG emissions increases GHG emissions from ammonia fertilizer production by 10%, from 2.18 to 2.39 g CO_2e/g ammonia produced (see Section 2.6.1.3).

2.6.1.3 Life Cycle Greenhouse Gas Emission Results

The impact of correcting the ammonia calculations and incorporating the weighted average coal/NG urea mix on the fertilizer GHG emissions results are shown below in Table 2.15 in g CO_2e/g fertilizer. As the table shows, the omitted upstream NG emissions in the ammonia calculations have a significant impact on NG-based ammonia emission results (10%) and urea (16%) emissions. Using the weighted fuel mix (6.7% coal/93.3% NG) for urea increases life cycle emissions a further 10%, from 0.88 to 0.97 g CO_2e/g urea, indicating that coal use has a significant impact on fertilizer life cycle emissions. Urea results were also calculated for a ―U.S. marginal‖ urea mix, represented as 80% coal/20% NG, to estimate the results for marginal (new capacity) urea fertilizer production. Calculating the indirect economic effects of fertilizer demand requires a global equilibrium model such as GTAP or FAPRI, but estimating new urea production capacity as 80% coal and 20% NG is a reasonable estimate. The GHG emission result for the marginal case is 1.88 g CO_2e/g urea, nearly twice as high as the U.S. average scenario. The carbon intensity of fertilizers used in the U.S. is expected to increase in the future as imported coal-based urea continues to displace domestic natural gas-based urea.

The fertilizer revisions discussed above and other important input changes (described below) were considered for U.S. dry mill corn and Brazilian sugar cane ethanol to explore the sensitivity of biofuel life cycle emission results to key input assumptions.

U.S. Dry Mill Corn Ethanol

Sensitivity analyses of U.S. dry mill corn ethanol were conducted to determine the emission impact of incremental revisions to input assumptions. The emission increments reported below for cases 1-5 are relative to the GREET default result for corn ethanol (79.1 g CO_2e/MJ), excluding the co-product credit for DGS. The DGS credit is excluded from the default corn ethanol emission intensity in this analysis because the credit is based on the life cycle results for corn and soybeans and increases proportionally to the carbon intensity of agricultural inputs, including fertilizers (the default GREET DGS credit is 14.5 g CO_2e/MJ).. Case 5 estimates the

DGS co-product credit using the input assumptions ARB used in developing the California LCFS. Case 6 sums the GHG emission increments for Cases 1-5, and represents the sensitivity of corn ethanol WTT emissions to GREET input assumptions. Figure 2.6 below shows the incremental emissions graphically. A summary of the six cases show in the figure is as follows:

Table 2.15. Ammonia and Urea Revised Life Cycle GHG Emissions

Fertilizer	Feedstock/Fuel	Life Cycle GHG Emissions, g CO_2e/g		
		GREET Default	Revised	Change
Ammonia	NG	2.18	2.39	0.21
	Coal	-[a]	4.86	-
Urea	NG	0.76	0.88	0.12
	Coal	-[a]	2.13	-
	U.S. Average[b]	0.76	0.97	0.20
	U.S. Marginal[c]	0.76	1.88	1.12

[a] GREET assumes all N fertilizer is produced from NG
[b] 6.7% coal, 93.3% NG
[c] 80% coal, 20% NG
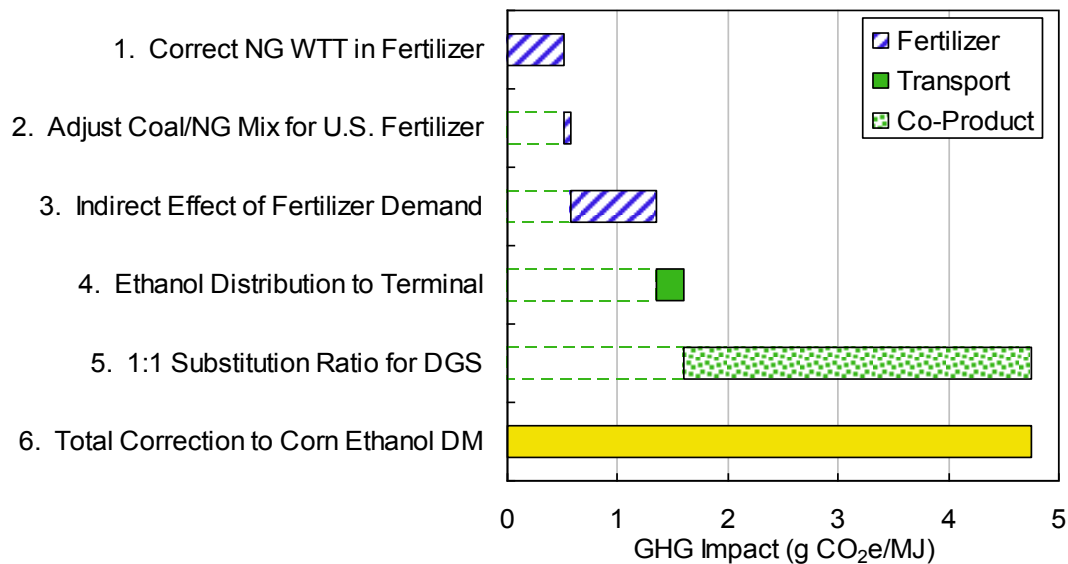
Figure 2.6. Incremental revisions to corn ethanol fuel cycle greenhouse gas emissions

1. Correct the GREET ammonia emission calculations to include the upstream emissions associated with producing the NG used (0.51 g CO_2e/MJ increase)
2. Adjust the feedstock mix for dry urea fertilizer used in the U.S. to 6.7% coal/93.3% NG from the default 100% NG (0.07 g CO_2e/MJ increase)

3. Estimate the indirect effect of fertilizer demand by considering that new N fertilizer production capacity is coal based. Estimate indirect fertilizer value as the difference between 80% coal/20% NG and 6.7% coal/93.3% NG (0.77 g CO_2e/MJ increase)
4. Include additional 30 miles of ethanol transport from bulk terminal to petroleum blending facility that is omitted in GREET (0.24 g CO_2e/MJ increase)
5. Adjust the distillers grain and solubles (DGS) displacement factors to 1 lb feed corn/lb DGS and zero for DGS displacing soybean meal and N in urea (3.16 g CO_2e/MJ increase)
6. The net impact of all these revisions increase the U.S. dry mill corn ethanol WTT by 4.8 g CO_2e/MJ

The net impact of correcting the ammonia error (Case 1) and applying the correct coal-weighted urea mix (Case 2) is a 0.6 g CO_2e/MJ GHG emissions increase, a modest but important revision because many biofuel pathways rely on fertilizer inputs. The conservative preliminary estimate for the indirect fertilizer increment (Case 3) is 0.8 g CO_2e/MJ. The additional corn ethanol distribution distance (Case 4) has a small impact on WTT emissions (0.2 g CO_2e/MJ). However, applying the California LCFS DGS co-product inputs (Case 5) significantly increases (3.2 g CO_2e/MJ) corn ethanol WTT emissions. The DGS credit is larger in the default GREET methodology than in the California LCFS methodology due to different co-product displacement factors. GREET assumes that DGS displaces corn on a one-to-one mass basis, in addition to displacing soy bean meal and nitrogen in urea, whereas the ARB LCFS method assumes only one-to-one feed corn displacement on a mass basis.

Brazilian Sugarcane Ethanol

Sensitivity calculations were performed for the Brazilian sugar cane ethanol pathway in GREET for three of the revisions discussed above and a Caribbean dehydration scenario. The emission changes shown below in Figure 2.7 are relative to the default GREET WTT sugar cane ethanol result (26.6 g CO_2e/MJ). Although Brazilian fertilizer data are difficult to locate, the nitrogen fertilizer mix is assumed to be 100% NG (the GREET default), due to the availability of cheap South American NG sources in Argentina, Chile, Peru, etc. Therefore, an emission increment for coal-weighted ammonia production was not calculated for fertilizer used in Brazil. Scenario 4 in the figure shows the net impact of using heavy fuel oil to dehydrate Brazilian ethanol to anhydrous ethanol in the Caribbean rather than using bagasse-based heat in Brazil (Macedo and Seabra 2008). Caribbean dehydration plants process more than one third (37%) of the Brazilian ethanol production to anhydrous ethanol. Ethanol dehydrated in the Caribbean becomes classified as a Caribbean fuel, thereby avoiding the U.S. tariff applied to Brazilian ethanol. The full emission increment for ethanol dehydrated with residual oil in the Caribbean compared to ethanol dehydrated with bagasse in Brazil is 2.3 g CO_2e/MJ. Incremental case descriptions and results are listed below. A summary of the six cases shown in the figure is as follows:

1. Correct the GREET ammonia emission calculations to include the upstream emissions associated with producing the NG used (0.15 g CO_2e/MJ increase)
2. Estimate the indirect effect of fertilizer demand by considering that new international N fertilizer production capacity is coal-based. Estimate indirect fertilizer value as the difference between 80% coal/20% NG and 100% NG-derived ammonia (1.02 g CO_2e/MJ increase)

3. Include additional 30 miles of ethanol transport from bulk terminal to petroleum blending facility that is omitted in GREET (0.24 g CO_2e/MJ increase)

4. Include the emissions for dehydration of 37% of Brazilian ethanol in the Caribbean using residual oil (1,900 Btu/gal) (0.86 g CO_2e/MJ increase)

5. The net impact of all these revisions change Brazilian sugarcane ethanol WTT by 2.3 g CO_2e/MJ
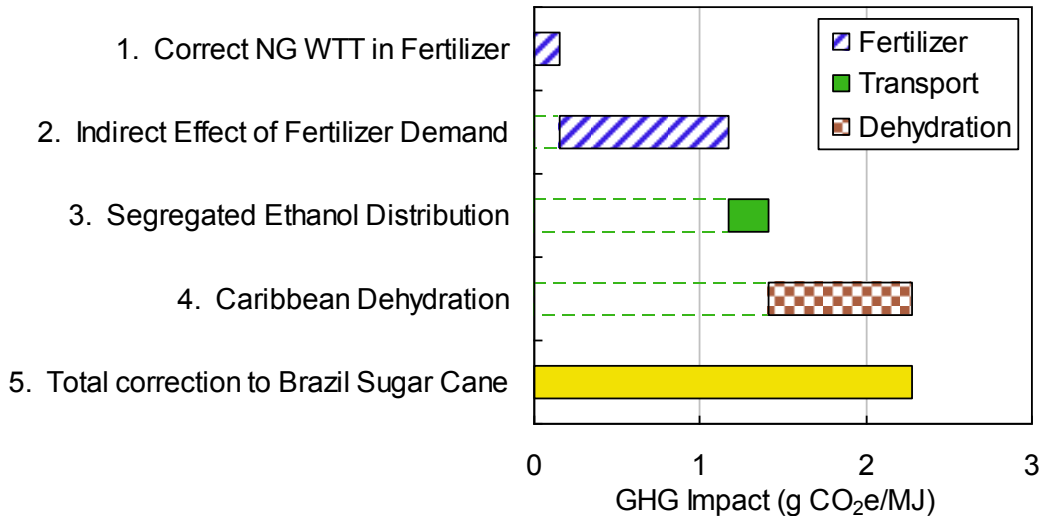
Figure 2.7. Incremental revisions to sugar cane ethanol fuel cycle greenhouse gas emissions

The net impact for the ammonia correction and coal-weighted urea inputs is a 0.3 g CO_2e/MJ increase, and the estimate for indirect effects of urea demand is a 0.9 g CO_2e/MJ increase. As described above for corn ethanol, the indirect emission estimate reflects the difference between the current NG predominant urea and future coal-predominant urea capacity (note that this is an indirect demand effect, not to be confused with an indirect land use change effect). In addition, as Figure 2.7 shows, ethanol dehydrated with residual oil results in significantly higher greenhouse gas emissions than ethanol dehydrated with bagasse (0.9 g CO_2e/MJ increase). The net impact of the life cycle revisions considered here are 2.3 g CO_2e/MJ.

There are two main differences between the corn and sugar cane ethanol pathways with respect to incorporating the above the fertilizer revisions into GREET:

- Sugar cane cultivation requires significantly less (93% less) nitrogen than corn farming, but a much higher percentage (85%) of nitrogen fertilizer used to grow sugar cane is urea compared to that for corn (21.1%).
- Sugar cane ethanol production does not produce animal feed in GREET or in most traditional life cycle analyses while corn ethanol produces DGS. Further:
  - The DGS credit is dependent on the corn production life cycle GHG emission result. This yields an unexpected and unjustifiable well-to-tank emission result for corn

ethanol: increasing the carbon intensity of corn production increases the pathway DGS credit.

- Sugar cane ethanol production co-produces vinasse syrup (black strap molasses). This is not typically included as a co-product in GREET or other LCAs, but it is used as animal feed with caloric and nutritional value.

The second difference highlights the fundamental problem with any life cycle analysis of biofuels that uses the pathway production result to calculate the co-product credit. This circuitous approach creates unjustifiable co-product credits for fuel pathways with inefficient, high-carbon intensity feedstock production.

2.6.1.4 Issues and Recommendations

In summary, several issues related to fertilizer use in two biofuel pathways were identified. These are summarized in Table 2.16 along with recommendations.

2.6.2 N$_2$O GREET Inputs

Net available nitrogen from the agricultural field system (including fertilizer input-N and crop residue-N) plus leaching N provide the basis for calculating N$_2$O release. The N$_2$O emission formula used in GREET implicitly assumes that the N$_2$O conversion rate is relatively constant among different nitrogen sources (e.g. fertilizer, soil material, etc); research is underway to assess whether this is a good assumption.

The corn biomass N-content in GREET (142 g/bu) comes from corn stover left on the field. We estimate a corn stover N-content of 108 g/bu based on the average Department of Energy (DOE) Energy Efficiency and Renewable Energy (EERE) statistics (USDOE 2007). The 201 g/bu biomass N content for soybean cultivation presumably represents fixed N and soybean residue-N left in the crop system after harvest (there is no documentation of this value or any of the biomass N-content values). The corn is assumed to be cultivated in rotation after soybeans, so that some of the residual soybean nitrogen will nourish the corn and reduce fertilizer needs. Further work needs to be done assessing the magnitude and variability of these impacts.

The input and output N in GREET is approximately balanced, despite the different sources used for the N-content of product removed. GREET doesn't account for all N sources, such as atmospheric N deposition. Additionally, nitrogen content in crops is highly dependent on the quantity, type and timing of the fertilizer-N applied (Mehdi, et al. 1999; Johnson, et al. 2007). Wood and grass are assigned a biomass N-content of zero because the wood residue left behind stores most of the N.

Table 2.16. Life Cycle Analysis Fertilizer Use Issues and Recommendations

Issues	Recommendations

• The GREET model fertilizer representation is too simplistic and inflexible to model U.S. average biofuel emissions
  - GREET only models natural gas-based feedstocks and products
• GREET cannot be used to determine emission sensitivities to different fertilizer scenarios
	• Review fertilizer and pesticide production and trade data and compile production rates (ton/yr) and fuel shares (% fuel) for domestic and imported feedstocks and products
	• Determine the domestic and international production share and feedstock/fuel shares for products consumed in the U.S. (U.S. average)
	• Evaluate the impact of the U.S. average fertilizer mix on biofuel pathways
	• The GREET fertilizer calculations should be expanded to:
	  - Include coal and residual oil inputs
	• Model ammonia production as a finished and intermediate product separately

• The GREET model contains an error that omits natural gas upstream emissions for feedstock natural gas used in ammonia production	• The GREET model ammonia emission formulas should be corrected to include upstream emissions for natural gas used as both a fuel and a feedstock
• The proportion of synthetic fertilizers produced from coal is rising, indicating an indirect emission associated with demand for nitrogen fertilizers	• Assessment of the indirect economic impact on greenhouse emissions should be estimated by a global economic model (such as GTAP or FAPRI
• Animal feed co-product credits circularly based on feedstock production results - Method does not represent reality • - Yields unjustifiably high credits for inefficient feedstock production	• Co-product credits should be based on life cycle inventory (LCI) data independent of the specific analysis • LCI data should represent the displaced product as closely as possible taking into account the effect of glutting markets
• Co-product credits have a significant impact on fuel cycle emissions and are highly sensitive to: - Emissions to produce displaced product • - Co-product displacement method used	• Sensitivity analysis of co-product allocation methods and resulting credits should be conducted to determine the inherent strengths and weaknesses of each.

2.6.3 N$_2$O Calculations

Calculations of soil N$_2$O emissions are based on nitrogen fertilizer inputs and biomass residue-N on a gram/bushel basis for corn and soy and gram/ton basis for wood and herbaceous biomass. The converted nitrogen is represented as N$_2$O based on the mass fraction of N$_2$O and N$_2$ in the molecule (44/28). Table 2.17 below shows the overall nitrogen balance for agricultural systems.

The table shows the fertilizer input, above and below ground biomass residue left in the soil, the N in the removed product (for comparison, not modeled in GREET) and the net available N. GREET assumes 1.3% (including 0.2% from leaching) of the available N is converted to N_2O.

Table 2.17. N_2O Emissions from Agricultural Operations (GREET 1.8c.0, year 2010)

	Corn	Soy	Wood	Grass
N_2O **Sources**	(g/bu)		(g/ton)	
Fixed N nutrient input (g/bu corn, soy) (g/ton wood, grass)	420	61.2	709	10,635
N content of above and below ground biomass[1] (g/bu corn, soy) (g/ton wood, grass)	142 (108)	201	0.0	0.0
N content of product removed[2] (g/bu corn, soy) (g/ton wood, grass)	314	742	2,177	4,627
Net available N	562	262	709	10,635
N Percent Conversion to N_2O	1.3%	1.3%	1.3%	1.3%
N_2O formed/N_2O-N (44 g/28 g)	1.57	1.57	1.57	1.57
Fixed N converted (g/bu corn, soy) (g/ton wood, grass)	7.44	3.47	9.39	140
N_2O Emissions (g/bu corn, soy) (g/ton wood, grass)	11.69	5.45	14.76	221

[1]GREET 1.8c.0 adds the N content for biomass residue to fertilizer input to yield net field available N. The corn N-content from U.S. DOE-EERE database is shown in parenthesis (USDOE 2007).

[2]The N-content of the product removed is shown for comparison(not used in GREET); The U.S. DOE-EERE N-content values for corn, wood and switch grass is presented in this row along with the soybean N-content from Sinclair et al. (Sinclair, et al. 2003; USDOE 2007).

Theoretically, the best approach to estimating N_2O emissions is as a percent conversion of input N alone (assuming that the rate of conversion of fertilizer N is similar to that of crop residue-N). Crop N is mostly removed from the system during harvest, and additional fertilizer applied to replace the N taken up by the crop during the previous fertilizer application will be reflected in the average fertilizer application rate. The percent conversion then reflects conversion of chemically unbound fertilizer, crop residue N, and leached nitrate-N. The GREET documentation (Wang 1999) states that N_2O emissions are indeed modeled as a percent conversion of just the fertilizer-N input (excluding crop N) plus leaching-N, but the model formulas actually include both fertilizer and biomass residue-N sources.

Although GREET documentation claims the N-conversion factor includes N_2O from leached N, the 1.3% conversion factor is appropriate for only field emissions; this factor is even on the low end of field conversion factors reviewed by Wang (0-3.2%) (Wang, 1999). GREET does not incorporate the potential N_2O resulting from legume nitrogen fixation. Soil N_2O emissions

resulting from soy cultivation are estimated to be relatively small in GREET because very little nitrogen fertilizer is needed. However, there is significant uncertainty in the magnitude of fixed nitrogen that leaks out of legume nodules into the soil system (Lindemann and Glover 2003; Rochette, et al. 2004; Lupwayi and Kennedy 2007). Many research groups are currently investigating this impact in different regions and under a range of environmental conditions. Table 2.18 below shows the N_2O emissions associated with farming and transportation for corn, soy, wood, and herbaceous biomass in year 2010 in GREET 1.8c.0. The values reflect the life cycle results for each category rather than direct combustion emissions. Soil emissions dominate these N_2O emissions, meaning that small changes in the percentage N conversion to N_2O have a large impact on the overall corn ethanol life cycle emissions.

Table 2.18. N_2O Emissions (grams/bushel Corn) from Corn Farming and Transportation Used in GREET 1.8c.0, Year 2010, Reflecting the Life Cycle Emission Intensities of Energy and Chemical Inputs.

	Corn	Soy	Wood	Grass
N_2O Sources	(g/bu)		(g/ton)	
Corn Farming	0.026	0.038	0.341	0.326
Nitrogen	0.685	0.100	1.156	17.35
P_2O_5	0.003	0.003	186	0.003
K_2O	0.002	0.003	0.003	0.002
$CaCO_3$	0.010	0	0	0
Herbicide	0.002	0.010	0.006	0.007
Insecticide	0	0	0.001	0
Transportation	0.012	0.013	0.360	0.226
N_2O Soil Emissions	11.69	5.45	14.76	221.4
Total (g N_2O/bu corn, soy, dry-ton wood, grass)	12.43	5.62	16.63	239.3
Total (g CO_2e/bu corn, soy, dry-ton wood, grass)	3,705	1,675	4.956	71,323
Total (g CO_2e/lb)	66.2	27.9	2.5	37.7

The overall N_2O emissions for the corn phase excluding co-product credits is 66.2 g CO_2e/lb corn and 62.2 g/lb of this is soil emissions arising from the 1.3% conversion factor. The soybean soil N_2O emissions may be too small, omitting legume-N contributed to the soil. GREET estimates of N_2O emissions from soybean production are less than half of those for corn production. On a mass basis, corn production has the highest N_2O emissions in GREET, nearly three times higher than for soybeans. However, the impact of intercropping soybeans and corn on soil N_2O emissions needs to be studied, including the allocation of these emissions between corn and soybeans. Switch grass cultivation has significant soil N_2O emissions in GREET due to the high N-fertilizer input.

2.6.4 Other N_2O Studies

Many studies, including those referenced above and others by the IFA/FAO, have estimated N_2O conversion rates at the field level for all of the different conditions listed above (IFA-FAO 2001). The U.S. as a whole has a conversion rate of approximately 2.5%, but the percentage of fixed N converted can vary dramatically by field, crop, fertilizer, etc., ranging from 0 to 12+% (IFA-FAO 2001). Further research is needed to develop region or field specific factors to properly estimate agricultural N_2O emissions. If the life cycle boundary is drawn only around the farm, the lifecycle N_2O calculation omit emissions from agricultural leaching and drainage and therefore be too low.

The Lifecycle Emissions Model (LEM, Delucchi, 2006) treats nitrogen deposition and leaching for individual ecosystem types and estimates the associated N_2O emission rates for each ecosystem. The data in the LEM shows the uptake of N, transport of N between ecosystems, and conversion to N_2O varies by an order of magnitude depending on whether the ecosystem is N-limited. LEM results show higher N_2O emissions related to crop cultivation than GREET estimates.

Table 2.19 shows LEM results for N_2O emissions for crop cultivation. This table is based on Table 1 from Delucchi's 2006 paper on biofuel lifecycle analysis, but it is based on the GWP factors in the latest IPCC assessment rather than carbon dioxide equivalency factors (CEF) developed by Delucchi for comparison[6]. Unlike the GREET model, LEM explicitly accounts for soil N_2O emissions due to biologically fixed-N and emissions unrelated to applied fertilizer (the third and fifth rows of values in the table). The relative magnitude of the soybean biological-N (45.1 g/bu) demonstrates the importance of this effect. Emissions unrelated to input fertilizer are low but still significant.

Table 2.19. N_2O Emissions (grams/bushel corn and soy, grams/ton grass and wood) Calculated by LEM (Delucchi 2006)

N_2O Sources	Corn	Soy	Wood	Grass
	(g/bu)		(g/ton)	
N_2O related to synthetic fertilizer N input	17.0	1.3	36.7	189.3
N_2O related to input animal manure N	0.5	0	0	0
N_2O related to input of biologically fixed N	0	45.1	0	0
N_2O related to crop residue N	5.0	17.7	4.8	22.6
N_2O from Cultivation, independent of N input	0.2	0.8	6.8	7.3
Total (N_2O g/bu corn, soy, dry-ton wood, grass)	22.7	64.9	48.3	219.2
Total (CO_2e g/bu corn, soy, dry-ton wood, grass)	6,780	19,340	14,400	65,320
Total (e CO_2e/lb)	121.q	322.3	7.2	32.7

---

[6] GWP for N_2O is 298 and CEF for N_2O is 251.

Table 2.19 omits four minor emission categories representing incremental effects and credits to facilitate comparison with GREET numbers. As the table shows, LEM estimates much larger crop cultivation N_2O emissions than GREET does, resulting in much larger net lifecycle emissions for all feedstocks. The LEM results also place the feedstocks in a different order of emission intensities. Unlike GREET, LEM estimates soybean emissions to be higher than corn emissions on a g/bu basis and grass emissions to be greater than wood emissions on a g/ton basis. These differences are due mostly to assumed differences in input fertilizer-N and crop residue-N.

2.6.5 Uncertainty in N_2O Emissions Estimates

Large uncertainty exists with regard to modeling the actual N conversion rate on a regional basis or for specific fields, due to the complex impact of the factors mentioned above on N conversion, the diffuse nature of farm N_2O emissions, emissions, and the strong impact N_2O emissions have on fuel cycle emissions. The main method for determining confidence intervals for life cycle results is to study the propagation of uncertainty over the parameters of interest.

Payraudeau, et al. applied the Monte Carlo numeric method to estimate the propagation of uncertainty in N loss for farming systems (Payraudeau, et al. 2007). This method assigns probability density functions (PDFs) to each parameter and a large number of parameter values are chosen randomly, according to their PDFs. Finally, the PDF of the results is determined based on the generated parameters and results. The IPCC guide for good practice and the management of uncertainty recommends use of normal or log-normal distributions, or triangular for use with a maximum or minimum value (IPCC 2001). Payraudeau et al. note the mean parameter values they chose are not final but illustrative and appropriate parameter values must be chosen for the analytical scale of interest (field, farm clusters, regional, state, country).

Further research is needed to understand the distribution of nitrogen conversion rates across different regions. Establishing and expanding a database of field and climate/soil characteristics, along with N input and conversion rates, can facilitate this effort. The data can be used to develop parameterized, multivariate regression models to estimate N-conversion rates as a function of relevant environmental factors. As discussed above, many researchers have already studied the impact of environmental and farm management factors in certain settings or conditions and published parameterized models that could be incorporated into the database. The results of this effort would provide statistical values (mean, variance, etc.) and ranges for use in a propagation of error analysis.

2.6.6 Conclusions and Recommendations

Many factors affect soil nitrous oxide emissions from agriculture, including fertilizer application rates, crop type, tillage practices, soil characteristics (pH, organic C content, texture) and climate type. However, fertilizer application is the main cause of nitrous oxide emissions. The default GREET input for soil fixed N (from applied fertilizer) conversion to N_2O is 1.3% based on the 2006 IPCC methodology for synthetic fertilizer (IPCC 2006). This includes contributions from both direct emissions (conversion of fixed nitrogen in the soil) and downstream emissions (resulting when the N in the system is volatilized or leached away in run-off). However, because EPA relies on FASOM and FAPRI to assess agricultural impacts, EPA should examine the life

cycle GHG emissions associated with fertilizer production and determine if the issues in GREET are also present in the FASOM and FAPRI analysis. The uncertainty over biological sources of N such as manure fertilizer should also be addressed.

EPA's treatment of N_2O emissions appears to be consistent with IPCC requirements; however it is difficult to verify. For example, international N_2O emissions are based on nitrogen application rates but it is difficult to verify the level of nitrogen application for each crop type. Because N_2O emissions are one of the largest GHG emission sources from biofuels production, the uncertainty in these emissions needs to be examined more carefully.

The overall assessment of nitrogen application rates, contribution of biogenic nitrogen (from manure and soybeans), trends in yield per acre, and nitrogen application per unit of feedstock need to be understood and reported on a more consistent basis. It is very difficult to verify how these factors are treated and the consistency among projections between the FASOM and FAPRI calculations needs to be addressed. This is discussed in the following section.

2.7   Analysis of EPA's RFS2 DRIA

2.7.1 General Comments

As discussed in the DRIA, EPA proposes to establish the revised RFS (RFS2) and to make the necessary program modifications as set forth in EISA. Several of these modifications are significantly notable. Among these is the thorough accounting of alternative fuels, including the future of second and third generation fuel technologies and developers, approaches to modeling, and inclusion of sensitivity analyses on several key topics, such as the controversial tools available for land use change (LUC) assessment.

EPA and its contractors have undertaken a very thorough analysis of the life cycle GHG emissions associated with biofuels and comparable petroleum fuels. The analysis strives to include both direct emissions and indirect land use emissions as directed by the EISA legislation.

FASOM and FAPRI are the most detailed tools available for the assessment of LUC, though they were not originally developed to quantify LUC impacts. FASOM was used to examine the U.S. agricultural GHG inventory for many years and provides considerable detail in all aspects of the agricultural and forestry sector. However, the model is not publically available, hasn't seen much validation in terms of quantifying LUC impacts associated with expanding biofuels production, and does not cover the international impacts of biofuels. Still, EPA's approach of linking FASOM and FAPRI together is understandable because of the high level of detail provided by the models and the modest level of validation the models have received.

EPA is also examining GTAP, which would provide an alternative modeling platform with global scope and a publically available model. GTAP is a global database of production and consumption information used to model bilateral international trade for entire economies. There are hundreds of GTAP models based on the database used to address different policy questions, and the GTAP database has thousands of users, assuring that the data are peer reviewed. GTAP

can produce useful results, but the quality of the results depends entirely on the model parameters used considering that the model has a large number of parameters to modify. The model is not ready-to-use out of the box and new commodity sectors must be developed for many analyses. GTAP crudely represents all oil seed crops in the same oil seed category. For example, conducting analyses on specific oil seeds, such as Malaysian palm oil, requires the user to develop a new commodity category and define all the relevant parameters.

In some cases, EPA's choice of model inputs as well as scenario parameters determines the outcome of the analysis in a significant way. These choices include the following:

- Assumption that no till farming with related soil carbon benefits is tied to stover collection for ethanol
- Assumption that low enteric methane emissions in Brazil will persist with cattle intensification
- Assumption that soil carbon storage from switch grass will persist as agricultural practices rotate
- Assumption that 2022 corn ethanol infrastructure will achieve theoretically possible performance
- Scenario based on built out 2022 infrastructure rather than existing infrastructure
- System boundary assumption based on credit for export electric power for U.S. and other biofuels facilities
- Scenario based on a 100 year time horizon
- Arbitrary discount rates for 100 year time horizon

These assumptions bias the analysis towards lower biofuel GHG emissions, when either a broader range of scenarios or more realistic scenarios would be appropriate. Again, we believe that EPA is attempting to complete the most detailed analysis with the tools available. However, in these instances, the choice of parameters strays from a balanced perspective. The following subsections provide a more detailed assessment of key factors that affect the GHG analysis. Appendix A discusses many of the life cycle analysis models EPA used in their analyses.

2.7.2 Projections and Assumptions for Fuel Scenarios

A number of assumptions concerning biofuels technology and farming practices determine the outcome of the GHG analysis. EPA focuses on the comparison of technologies in 2022 as these reflect the full implementation of the rule. However, this presentation masks the performance of near-term technologies. It also may miss the competing impacts of international biofuels use. Some of the key issues are identified in Table 2.20.

2.7.2.1 Feedstock and Resource Mix in Year 2022

EPA considered a mix of plant types and configurations projected to be in operation and producing renewable fuels in 2022. The analysis of fuel use in 2022 implies a mix of agricultural yields, plant efficiencies, and demands for crops. The main differences between this overall

impacts analysis and the analysis conducted to develop the threshold values for the individual fuels is that the total production change in renewable fuels were analyzed in one scenario as opposed to looking at individual fuel impacts calculated per unit of fuel produced. When analyzing the impact of the total 36 billion gallons of renewable fuel needed, EPA also considered the agricultural sector interactions necessary to produce the full complement of feedstock.

Table 2.20. Key Issues in the EPA Analysis of International Biofuels Use

Parameter	EPA Approach	Comment
2005 to 2022 implementation	Calculate GHG emissions for evolving mix through 2022	EPA estimates the full implementation of the rule. High volume near term effects are comingled with speculative long term benefits.
Calculation of 2022 scenario	Present increments in 2022 (e.g. 12.4 to 15 billion gal of corn ethanol)	Highlights GHG impacts of the best technology with the highest projected yields. Direct GHG and indirect LUC impacts are higher for near term technologies.
Analysis of U.S. scenario in 2022	Examines impact of 36 billion gal of biofuels in U.S.	Analysis does not consider additional biofuels use and mandates in other countries.
Enteric methane	Assumes existing IPCC factors for enteric methane (DRIA Table 2.6-19, pg 346)	EPA assumes international methane emissions from enteric fermentation will persist. However, agricultural intensification in developing countries will result in practices that resemble those used in industrial countries.
Projection of yields and fertilizer use	FASOM projections for crop yields. EPA to examine nitrogen requirements as yields improve (DRIA p 646)	The requirements for more nitrogen with yield improvement should be carefully examined as nitrogen impacts on direct energy requirements and N_2O emissions are important GHG contributors.
Co-product electricity credit	Unclear treatment of self generated power	Electricity credits associated with cellulosic ethanol and sugar cane will likely be sold or used to meet renewable power requirements, CDM projects, or other GHG initiatives. Including the credit in the GHG emissions or allocating biorefinery emissions to power would result in double counting.

EPA points out the difficulty in simply adding up the individual lifecycle results determined and then multiplying by their respective volumes to assess the overall rule impacts. EPA notes ―analyses are separate in that the overall rule impacts capture interactions between the different fuels but cannot be broken out into per fuels impacts, while the threshold values represent impacts of specific fuels but do not account for all the interactions" (EPA, 2009, p. 428).

One challenging aggregation question is how to treat the new and existing corn ethanol capacity. Existing corn ethanol is ―grandfathered" within the rule. EPA's analysis effectively represents the growth in corn ethanol capacity from 9.85 to 15 billion gallons per year as a mix of projected future technologies with new corn capacity as shown in Table 2.21. However, because existing capacity may be upgraded to lower GHG options absent the RFS, and new capacity may be built with conventional technology, EPA should examine both the existing inventory of corn ethanol capacity rather than just the presumed increment associated with the rule. While the existing plants are not required by the rule, their continued operation is supported by the rule. Furthermore, their energy consumption, co-products, and corn consumption affects the indirect energy impacts of the corn ethanol plants and other biofuel facilities affected by the rule. EPA should examine changes in each biofuel category due to new capacity (additions) and conversions/upgrades to other biofuel production capacity (subtractions). The biofuel category projections can then be aggregated and analyzed.

Table 2.21. EPA's Projected U.S. Biofuel Production Capacities (EPA 2009)

Category	Feedstock	Production Capacity, billion gal/yr	
		2009	2022
Cellulosic ethanol	Herbaceous biomass	0	16
Biomass based diesel	FAME biodiesel	0.5	0.81
	Non co-processed renewable diesel	0	0.19
Other advanced biofuel	Co-processed renewable diesel	0	0.19
	Imported ethanol	0.5	3.14
Non-advanced biofuel	Corn ethanol	9.85	15
	Total	10.85	35.33

The EPA analysis also fails to address how a global growth in biofuels use would affect the overall analysis. The EU is implementing mandates for biofuel use and other regions may follow suit. The DRIA does not take into account the limited land available globally and how additional demands on biofuels may amplify LUC impacts.

2.7.2.2 Technology Improvement over Time

It seems more appropriate to develop regulations based on actual practices, with provisions to update as those practices change. EPA does note, however: ―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." (EPA 2009, p. 296). It is unclear whether the predictions are conservative or likely, and how the scenarios were quantified. Technological change could occur more or less rapidly. How this will affect the fuel LCA is not known at this time. The DRIA identifies many technologies that could occur. Advances in the corn ethanol industry, including: cold starch fermentation, dry fractionation, corn oil extraction, membrane replacement, and combined heat and power would all improve energy consumption or yield.

Projecting technological changes, yields, and policies thirteen years into the future increases uncertainty, and because efficiencies and yields are projected to be higher, this approach could understate near-term emissions. Current GHG emissions ratings should be based on best projections over time and ratings should be updated to keep pace with technological advances. Unfortunately tracking renewable fuel production technologies over time complicates the time frame dependent analysis. Nonetheless, EPA could show the impact over, perhaps, five year time steps and shown in intervals as 5 year reports. This is the premise in the FAPRI analysis. The report could provide the g/MJ rating for each tranche of fuel produced. Otherwise, fuel volumes and projections in year 2022 could diminish (or draw upon?) the ratings for early years.

The performance of all parameters is generally projected to improve over time. An example, corn farming energy, is shown in Figure 2.8 (from GREET). The energy used for farming the corn in 2005 (14,000 Btu/bu) represents the equivalent of about 7 g/MJ of GHG emissions. Projections for future improvements would result in the equivalent of about a 2 g/MJ reduction in GHG emissions by 2020. Similarly, process heat requirements, corn yield, and other parameters are also projected to improve. EPA could identify the g/MJ intensity and assumptions corresponding to each tranche of fuels that are rated. Note that the FASOM energy inputs calculated from the charts in the DRIA are consistent with the projections in GREET. The basis for these projections should be documented.

2.7.2.3   Cellulosic Technologies

EPA‗s analysis implies a high degree of certainty with regard to cellulosic technologies. The 2022 targets are ambitious but perhaps too high for the current state of these technologies. The DRIA provides a review of important renewable fuel developers and planned projects, and considers the feasibility of feedstock supply. EPA reviewed biomass supply studies conducted by DOE, USDA, and Marie Walsh (formerly of Oak Ridge National Laboratory). These studies estimate the feasible quantities of forestry biomass available in the U.S. at various prices, but neglect the spatial distribution and quality (density) of the biomass resources, and may overestimate the feasible biomass available. EPA examined the feasibility of cellulosic biofuel plant construction by comparing the build rates necessary to meet EISA biofuel volume mandates with recent build rates of starch-based ethanol plants, and concluded the rates are similar. In addition to the feedstock availability and construction feasibility, biomass

competition for other uses, water availability, investment requirements, construction lead times, and capacity, infrastructure logistics, and other factors will pose significant logistical challenges.
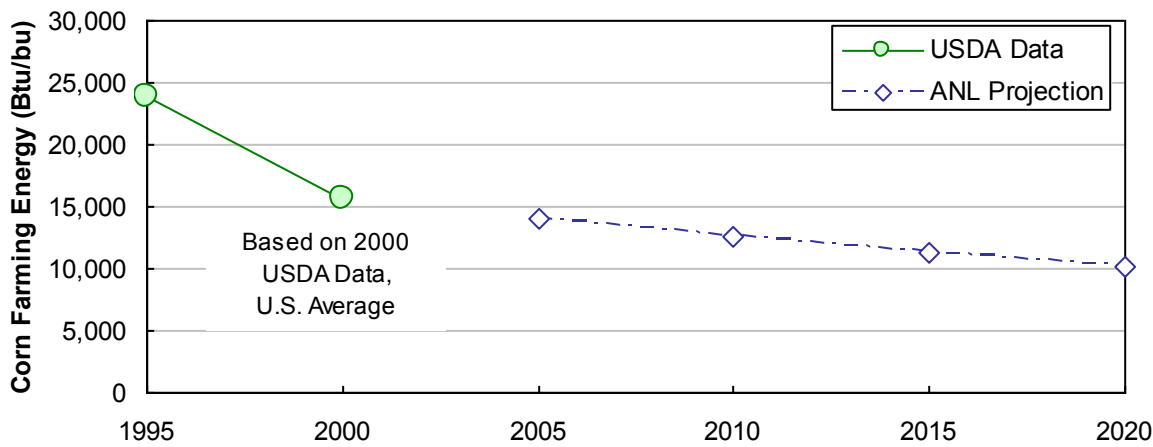
Figure 2.8. Projected U.S. corn farming energy (Source GREET and DRIA[7])

Cellulosic ethanol facilities can operate with a wide range of conditions. The range in feedstocks and chemicals as well as yields and co-products will result in a wide range in GHG emissions from cellulosic ethanol facilities. Some of the various operating conditions include:

- Enzymatic conversion technologies which require an enzyme plant and feedstocks for enzyme production.
- Acid hydrolysis which requires the import of acid, neutralizing agent, and the export of neutralized material.
- Capture of lignin co-product
- Capture of lignin residue or gasification of feedstock for power production

The performance of cellulosic ethanol plants depends on the process configuration, location, and feedstock. Projected ethanol production yields range from 50 to 90 gal/dry ton combined with a range of electric power production from net importers of power to exporting over 3 kWh/gal of ethanol produced. The actual material inputs and yields of these plants need to be taken into account.

The treatment of co-product power is especially challenging. In general, plants with lower feedstock conversion (gal/ton) produce more residue and more export power. The approach for assigning emissions to co-products needs to be carefully considered. Electric power will likely be sold into a market that either requires renewable power or provides an incentive such as clean development mechanism (CDM) funding. In such cases no credit or allocation of emissions

---

[7] Energy inputs for FASOM calculated from DRIA Figures 2.6.-5, -7, and -10 showing 13 gal diesel, and 3.3 gal gasoline, 10.8 kWh electricity per acre and 170 bu/acre.

should be applied to export power. The DRIA assumes that excess electricity generated by biofuel plants will displace the grid mix (U.S. or Brazil average), and credits the co-product power according to the GREET electricity mix. This approach can yield unreasonably large co-product credits when significant excess electricity is produced; 3 kWh/gal electricity yields a 28 g CO_2e/MJ credit when displacing the U.S. grid mix. The EPA is also examining ways of incorporating the electricity off-sets with their secondary energy analysis in the NEMS model.

The DRIA does not consider the best use of biomass for reducing GHG emissions. In almost all cases, the production of electric power from biomass reduces more GHG emissions than the displacement of gasoline as biofuel (Wang, et al. 1999). Thus, the alternative use of biomass as a feedstock for electric power generation should also be considered as an alternative use of the feedstock. The performance of cellulosic technologies also poses some important questions about their LUC impacts discussed in the following Section 2.7.3.

2.7.2.4   Recommendations for Technology Mix

- Analyze fuels in tranches corresponding to realistic projections for production technology including existing ethanol capacity
- Examine scenario where plants are not aggressively retrofitted to better performance
- Develop rankings that allow for adjustments for actual plant performance
- Document aggregate plant performance parameters by year
- Carefully examine approach and policy regarding credit/allocation to renewable power from biomass combustion

2.7.3   Direct and Indirect LUC Impacts

Analyzing the full land use impacts of biofuels production requires an assessment of both direct and indirect land use conversion. Note that all land use conversion is ultimately direct *somewhere*. The distinction is that *direct* land use conversion refers to lands converted for the direct production of biofuels, whereas *indirect* land use conversion refers to lands converted *in response to* expanded biofuels production. For example, an expanding corn ethanol capacity does not simply result in converting and planting additional U.S. crop land; it involves a reduction of acres in soybeans, which are (mostly) replaced elsewhere, in some cases following deforestation. Estimating these market-mediated impacts is typically accomplished using agricultural-economic models.

EPA uses the FASOM and FAPRI agricultural models to estimate the cropland affected by ethanol production. The analysis depends upon the supply and demand for land, crops, and products including animal feed and beef. The net effect depends on key economic inputs that are exogenous to the agricultural models used. EPA's analysis should provide greater transparency to these input assumptions and the sensitivity of model results to these assumptions. Comments on the analysis of LUC are summarized in Table 2.22 below.

Different ecosystem types store different quantities of carbon in the soil and in the above-ground biomass. Conversion of land between ecosystem types results in a new equilibrium carbon

storage level over time, with associated storage or release of carbon. Converting forests to pasture results in the loss of large quantities of above-ground biomass, but little change in soil carbon. Conversion of forest or pasture to cropland releases large quantities of soil carbon if the cropland is tilled, and far less if no-till practices are used (Houghton and Hackler 1999; Murty, et al. 2002). Converting cropland to pasture or forest generally results in increased storage of carbon.

Table 2.22. Comments on the EPA Analysis of Land Use Change

Parameter	EPA Approach	Comment
Evaluate direct and indirect land use conversion	Estimate LUC with FASOM and FAPRI. Assess soil carbon change with DAYCENT and CENTURY.	EPA used some of the best available models to assess the soil carbon emissions associated with land use. Both the models, inputs, and reporting of outputs are very complicated; so the documentation could be more structured. Example: 2022 U.S. corn ethanol targets would convert 747,000 ha of land in Brazil to agriculture (Estimated by FAPRI).
'Best' biofuel	Calculation in FAPRI chooses switch grass ethanol as lowest emitter of GHG emissions.	This "prediction" is based on the input assumptions of very low capital cost, high yield, and low collection cost. In practice costs will be higher.
Reduce N_2O Emissions	Uses IPCC guidelines for N_2O emissions. Assume that corn stover removal will require additional N fertilizer.	The assumption is that removal will require more inputs to make up for lost residue nutrients. 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. These results are dependent on agricultural sector inputs and emission assumptions that are being updated for the final rule (e.g., N_2O emissions).
Corn stover direct LUC	EPA appears to apply a credit for no-till corn farming.	The practice of no-till corn farming is not associated only with stover collection. Furthermore, effect of removing so much stover from the land on soil carbon storage has not been thoroughly examined.
Switch grass direct LUC	Apparently a soil carbon storage credit is applied due to the growth of roots from the switch grass	Will any soil carbon benefit of switch grass have a lasting effect? Once soil carbon is built up, what is to prevent a switch to another crop?

Biogenic GHG fluxes associated with agriculture include the storage of atmospheric carbon in plant biomass due to photosynthesis, the deposition of carbon in the soil due to shedding of roots and incorporation of plant residues, and emissions of methane and N_2O from agricultural practices. The atmospheric uptake of carbon dioxide into plant material is considered a credit against the biogenic carbon in the fuel. However, the biogenic components of feedstock

production and land use are important elements of a biofuel's life cycle impact and these emissions should include changes in soil carbon and above ground flora.

Ecosystems store and release carbon as plants, fungi, and other biota grow and decompose. Carbon emissions associated with the conversion of land to agriculture vary over time and with ecosystem type. The IPCC estimates the levels of carbon storage in the plant material and soil, and these soil carbon factors are used to develop international GHG inventories (IPCC 2003).

These carbon stocks have been converted to land use carbon factors on the country and regional scale for 13 countries by Winrock International (Harris, et al 2008). The extent of recent (2001– 2004) land use change was examined using MODIS satellite imagery with a 1 square kilometer resolution. The previous version of the imagery data was determined to be 75-80% accurate globally and 60-90% accurate for individual land types, and the most recent version is expected to be at least as accurate. The Winrock emission factors are an important improvement on the previous effort to quantify international land use change impacts, which used FAPRI and FASOM to estimate changes in agricultural production combined with emission factors from U.S. models and available literature. However, the Winrock results are subject to numerous sources of error concerning the land-use classification of the image pixels (1 pixel = 1 sq. km) and the low pixel resolution. Pixels can be categorized incorrectly due to land cover types excluded from the categorization scheme, color mixing or other factors. The IPCC carbon factors are reasonable estimates of carbon storage and have been reviewed and validated by numerous sources. In general, the Winrock approach yields reasonable and useful emission factors for homogenous land use types, but the results become less reliable in regions with highly heterogeneous land cover.

2.7.3.1 Direct Land Use from Corn Stover and Switch Grass

EPA's analysis shows a significant reduction in GHG emissions for several biofuels crops, as shown in Table 2.23 below. Most significantly, corn stover and switch grass results in a negative LUC that is associated with the buildup of root material in the soil. The LUC impact of soybean biodiesel is likely more complex and due to more subtle co-product issues and should be explained further.

Table 2.23. Land Use Change GHG Emission Reductions

Crop	Domestic LUC (g CO$_2$/mmBtu)	
	2022 to 2026	**2027 to 2041**
Soybeans (Biodiesel)	-1,045	-348
Sugar Cane (Ethanol)	0	0
Corn (Ethanol)	6,705	6,705
Corn Stover (Ethanol)	-9,129	-9,129
Switch Grass	-7,601	-7,601

The soil carbon storage associated with corn stover is likely due to EPA assuming that no stover collection will cause a change to no till farming practices. The no till practice appears to result in improved soil carbon storage with most measurements conducted to a 30 cm soil depth. While no-till farming may be required for stover collection for ethanol production, there are many other applications of no-till farming. The practice of examining and attributing no-till farming benefits to stover derived ethanol is conceptually flawed.

The impacts of using corn stover and other agricultural residues for fuel production need to be examined by EPA in greater detail. Agricultural residues are traditionally left in fields because they protect the soil from erosion, maintain higher levels of organic carbon in the soil, and aid in water management. Residue removal accelerates soil erosion, especially for row crops like corn. The relationship between the residue coverage and soil erosion is exponential, with erosion accelerating as residue coverage becomes thinner, but the severity varies across regions. Soil organic carbon (SOC) matter is very important for soil health, crop production, and carbon sequestration. EPA needs to determine the quantity of stover in the U.S. that can be sustainably removed without degrading SOC and carbon sequestration. EPA does acknowledge that the collection of stover for ethanol production also requires further examination from a soil health perspective. Several studies discuss the potential impacts of residue removal in greater detail (Cruse and Herndl 2009, Wilheim, et al. 2007). Wilhelm et al. conclude that the quantity of stover required to maintain SOC levels is higher than the quantity required to prevent soil erosion; this means the stover left in the fields to maintain SOC levels is more than adequate to prevent soil erosion. However, the crucial metric (SOC, C sequestration, soil erosion, water levels and quality) that constrains residue collection likely varies across landscapes, indicating that spatially variable land management techniques are needed.

Residue cover affects water consumption and water quality through two main mechanisms. The residue cover aids in water conservation and maintaining water quality by limiting soil evaporation, minimizing erosion, and reducing chemical fertilizer requirements. Nitrogen (N) and phosphorus (P) are the main nutrients that pollute downstream water bodies. N and P levels in downfield water bodies are directly proportionate to fertilizer inputs, so increasing fertilizer use to compensate for residue removal leads to a higher nitrogen concentration of N in runoff. P is only mildly water soluble and is transported downstream by soil erosion. EPA needs to carefully consider the water impact associated with residue removal and expanded agricultural production in general.

The overall life cycle of carbon stored in crop roots remains uncertain. While certain cropping systems may store additional carbon, the same carbon can be released by conversion to a different crop that requires tilling. Therefore it is important to consider GHG analysis time frame and intercropping patterns

2.7.3.2 LUC Recommendations

- Examine corn stover assuming no causality between no till and stover collection
- Examine impacts of crop residue removal on soil organic carbon, soil carbon storage, crop productivity, agricultural water consumption and downstream water quality

- Examine impact of agricultural intensification in developing countries on international methane emissions from on enteric fermentation and identify causes for the impacts
- Assess impacts of crop rotations on soil carbon storage.
  - Would no till and switch grass farming just restore soil carbon and allow for a future soil carbon release when the land is converted?
  - What time frame is most appropriate for assessing soil carbon in intercropping systems?
- Examine nitrogen impacts associated with a shift in soybean rotation from U.S. corn-soybean or corn-corn-soybean to other rotations. A soybean monoculture could result in an increase in fixed nitrogen with impacts on soil carbon and N_2O release.

2.7.3.3   LUC References

Cruse, R. M. and C.G. Herndl, (2009) Balancing Corn Stover Harvest for Biofuels with Soil and Water Conservation, Journal of Soil and Water Conservation, July/August 2009—vol. 64, no. 4.

Guo, L. B. and R. M. Gifford (2002). Soil Carbon Stocks and Land Use Change: a Meta Analysis. Global Change Biology 8(4): 345-360.

Houghton, R. A. and J. L. Hackler (1999). Emissions of Carbon from Forestry and Land-use Change in Tropical Asia. Global Change Biology 5(4): 481-492.

IPCC (2003). Good Practice Guidance for Land Use. Land-Use Change and Forestry. 4-88788-003-0. Hayama, Kanagawa, Japan, Institute for Global Environmental Strategies (IGES).

IPCC, Available at http://www.ipcc-nggip.iges.or.jp/public/gpglulucf/gpglulucf.htm.

Murty, D., M. U. F. Kirschbaum, et al. (2002). Does Conversion of Forest to Agricultural Land Change Soil Carbon and Nitrogen? A Review of the Literature. Global Change Biology 8(2): 105-123.

Searchinger, T., R. Heimlich, et al. (2008). Use of U.S. Croplands for Biofuels Increases Greenhouse Gases Through Emissions from Land Use Change. Science: 1151861.

Wilhelm, W. W., et al. (2007). Corn Stover to Sustain Soil Organic Carbon Further Constrains Biomass Supply, Agron. J. 99:1665–1667

2.7.4   Time Horizon

EPA focuses on two time horizons with discount rate options: 100 year horizon with 2% discount rate and 30 year horizon with 0% discount rate. The choice of time horizon is significant because it dictates which impacts to count and provides an aggregate metric of the impact of biofuels production rather than a year by year impact on the global inventory. The composite value is a simple to digest figure. Amortizing GHG emissions over a time horizon also smoothes out uncertainties associated with the timing of carbon releases.

The treatment of emissions using the net present value of emission flows over 100 years is a poor choice for several reasons. This time horizon is beyond the target dates of the GHG goals. Thus, there is a decreasing probability that the technologies put into place to meet the current GHG reduction target dates will still be in place decades into the future. The more realistic choice would be to count cumulative GHG emissions, perhaps over 30 years, or even 20 years, which can be more accurately accounted for as a _project life'.

Ultimately, the effect of land use conversion will show up in annual emission inventories. The buildup of GHG emissions as land is converted over the next 20 years is not well represented by the amortization of carbon release over a time horizon. EPA should also show an inventory of cumulative GHG emissions associated with land use conversion. Such an analysis would illustrate the carbon debt undertaken by some biofuels options better than the representation of annual emissions. A summary of comments on EPA's treatment of the time horizon is given in Table 2.24.

Table 2.24. Comments on the Time Horizon Used in the EPA Analysis

Parameter	EPA Approach	Comment
Time Horizon 100 or 30 years (with or without discount rate)	Put petroleum and corn ethanol on _equal footing' using NPV values GHG t / $(1 + r)^t$, where t = the year, where year 0 is the first year of analysis r = the discount rate GHGt = the net flow of GHG emissions in year t	EPA examines 0, 2 and 3% discount rates for a 100 year time horizon and selects the mid case to compare with the 30 year time horizon option. The rational for selecting discount rates and a 100 year analysis period is not well supported. In particular, a 100 year analysis period is a poor choice because the technologies used to achieve near-term GHG goals may no longer be in use over the very long time term.

The timing of the impact of land use change and ongoing renewable fuels benefits are discussed but not treated in relative terms. Instead, the RIA considers absolute tons of emissions in total for their overall fuel use scenarios, and not a threshold comparison of renewable fuels to petroleum fuels. Nevertheless, EPA's results can be presented in a similar manner to that used in the individual fuels analysis in that the net benefits over time can be determined for different discount rates and over different time frames.

EPA calculates a '33 year payback' period for the standard corn ethanol production pathway under the 30-yr scenario with 0% discount rate. This scenario will increase emissions by 5% over 30 years (with 0% discount rate). For corn, the payback begins a reduction past 40 years where at 50 years and 0% discount, a 17% reduction in emissions is calculated. EPA concludes that projecting the impact of U.S. policy on international land use is a task with inherent uncertainty, even with available models and the selected time horizon scenarios. The complexities and interactions involved mean that LUC results are inconclusive. Because of this issue, EPA performed five _land use' sensitivity analyses as outlined in the sensitivity analysis section (Section 2.7.7).

What the time horizon really refers to is a ―pay back" period. EPA suggests that biofuel-induced land use change can produce significant near-term increases in GHG emissions; however, over subsequent years, the displacement of petroleum by biofuels that generate lower GHG emissions when combusted can ―pay back" earlier land conversion impacts. Therefore, the time horizon over which emissions are analyzed and the application of a discount rate to value near-term

versus longer-term emissions are critical factors. Several other variations of time period and discount rate are also discussed in the proposed rule but no clear consensus is drawn.

The EPA DRIA provides draft GHG emission reductions that result for two time horizon/discount rate approaches for a sample of fuel pathways evaluated in the proposed rulemaking (EPA 2009, Tables 2.8-1 and 2.8-2, with associated discussion). EPA has not yet chosen a specific approach.

The following are recommendations related to the time horizon issue:

- The analysis should be based on a simple 20 or 30 year time horizon. Longer term time horizons introduce the desire for discounting emissions, which distorts the impact of future emissions
- 100 year time horizons introduce uncertainty and are contrary to the intent of the rule which is to rate fuels according to their GHG benefits.

2.7.5 Agricultural Commodity Price Impacts

The RFS program is likely to spur the increased use of renewable transportation fuels made from agricultural crops (at least initially), and it is expected that most of these crops will be produced in the U.S. EPA estimated the change in the price of various agricultural products as a result of this rulemaking. Table 2.25 provides EPA 2022 estimates for commodity price increases for corn, soybeans, sugarcane, and beef. Based on these figures, EPA estimates that U.S. food costs. would increase by $10 per person per year by 2022 while net U.S. farm income would increase by $7.1 billion dollars (10.6%).

Table 2.25. EPA Estimates for Agricultural Commodity Price Increases

Commodity	Price Change in 2022 Scenario
Corn	$0.15 / bushel
Soybeans	$0.29 / bushel
Sugarcane	$13.34 / ton
Beef	$0.93 / hundred pounds

Further, EPA states these higher commodity prices will then allow U.S. corn exports to fall from 2.7 billion bushels to 2.4 billion bushels (this is a 10% decrease) by 2022, while U.S. exports of soybeans would decrease from 1.03 billion bushels to 943 million bushels (a 9.3% decrease). Price effects are an important driver in EPA's analysis, which predicts that agricultural product prices will rise sufficiently to reduce the demand for cattle with a subsequent reduction in cattle emissions. Similarly, soybean output is predicted to drop, while at the same time Brazilian soybean output continues to grow.

EPA's analysis bundles food price rationing with land use impacts. The food price rationing effect represents a reduction in food consumption due to pressures on agricultural commodities. While the impact of food prices is small per unit of food consumed, the net aggregate impact that is predicted is a reduction in food consumption because of the use of biofuels. This result is inconsistent with the preservation of a consistent system boundary between the base case and the renewable fuel cases. Changing the amount of food available worldwide is a fundamental issue that extends beyond the realm of fuel choices. Therefore, EPA should also perform the analysis assuming a fixed level of food consumption (with resultant higher prices).

The EPA addresses some components of the life cycle of biofuels (commodity prices and acres planted) with an equilibrium analysis while holding other components fixed (fertilizer cost, natural gas cost, etc.). The combination of land impacts in Brazil is also a static assumption. By design, partial equilibrium models such as FAPRI include only a subset of industrial sectors, thus the term ―partial‖ equilibrium. The analysis applies economic effects where possible and convenient but excludes them from other parts of the fuel cycle, which makes the entire analysis appear suspect.

The analysis of indirect land use change requires an evaluation of market-mediated effects relating to land, crops, and foodstuffs. The economic analysis is necessary to address the changes in production, imports, and exports resulting from a ―shock‖ to the economic equilibrium, such as a large expansion in corn ethanol production. Further assumptions are required to determine which land types are displaced due to farming activities. This analysis goes beyond the traditional life cycle modeling of energy inputs.

To facilitate transparency, the effect of food price rationing should be unbundled from the land use impact. EPA could present an assessment of the acres affected and GHG emissions associated with these acres with and without food price effects. Also, if energy price modeling or other economic factors are available for an integrated life cycle analysis, the results can be presented with and without price effects. Lacking such a comparison, the reader has no feel for the relative importance of each effect.

EPA's analysis also does not consider the secondary impact of reduced soybean output on soybean oil production. Palm oil provides a substitute for soybean oil and the prices of palm oil and soybean oil are closely linked. A reduction in soybean oil supply would result in increases in soybean oil prices and increased supply of palm oil.

2.7.5.1 Indirect Effects

EPA used the EPA-NEMS analysis to determine the indirect impacts of increased ethanol production on energy consumption in the residential, commercial and non-refining industrial sectors. EPA calculates indirect impacts for various cases in different years, but the results presented in the DRIA don't include direct impacts so it's impossible to judge what is included (DRIA Table 2.5-2, page 316). The change in energy consumption from the control to the lower ethanol case in the NEMS analysis was mostly due to increased coal use and decreased nuclear. The NEMS analysis and FAPRI need further examination to determine methods and results for indirect impacts. For example, EPA should show the amount of direct inputs for each fuel

similar to the summary of indirect effects. The relationship between indirect effects and direct inputs can then be reviewed.

2.7.5.2   Non-Equilibrium Economics

Equilibrium models predict the ultimate supply and demand in commodity markets resulting from an assumed ―shock" to the presumed pre-existing equilibrium. By focusing on the assumed final equilibrium state, transitory interim changes that occur between the two equilibrium states are ignored. In practice, short term price spikes can be sufficient to cause temporary production changes that might be reversed as markets settle, while the land use conversion and carbon emissions accompanying these production changes are *not* reversed. Recently, soybean prices reached $15/bu[8], while soybean prices ranged from $6/bu to $11/bu for many decades. This effect is due to a change in crop rotations from corn-corn-beans to three rotations of corn, the international soybean oil market (the Chinese had a low rapeseed harvest which led to an increased demand for soybean imports), and other effects. Much higher price excursions are possible with the introduction of biofuels on an unprecedented scale.

Certainly a doubling in soybean price does not reflect the cost of production or the long-term equilibrium price if more land were brought into production globally. However, farmers may act on near term price signals to clear native lands for crops. For example, it could be possible to lock in futures prices for soybeans and clear land in Brazil for soybean production that may be profitable for only a few years at these prices. The land might later be abandoned for pastureland or revert to Savannah.

The environmental risks are abundant. Near term price effects might cause farmers to overshoot the land use conversion predicted for biofuel production. The land use has carbon consequences but also exposes native land to infrastructure that may prevent the reversion back to native forest.

Indirect effects from the RFS2 proposal are also reflected in commodity prices. For example, corn is a major component in animal feed in the U.S., and as corn prices rise in 2022, EPA predicts beef prices to increase $0.93 per hundred pounds (1.4%), relative to the reference case price of $67.72 per hundred pounds. Therefore, increased U.S. corn prices would have a direct impact on the value of U.S. agricultural land. EPA's results show that, as the demand for corn and other farm products increases, the price of U.S. farm land would also increase. This analysis shows that land prices would increase by approximately 21% by 2022, relative to the Reference Case.

2.7.5.3   Price Effect Recommendations

- Perform analysis holding food consumption constant to maintain a consistent system boundary
    - This approach separates the effects of food and biofuel production

---

[8] For example, see http://futures.tradingcharts.com/chart/SB/W

- The difference between cases with and without constant food consumption represents the relative contributions of food versus biofuel production to changes in agricultural commodity prices
- Examine LUC impacts under non-equilibrium conditions (i.e., those associated with short term swings in feedstock prices). Such indirect effects may cause LUC that does not revert in the long run.
- Show direct impacts for NEMS analysis (quads per year of natural gas, coal, diesel fuel, electric power) that are consistent with the indirect effects predicted by NEMS.

2.7.6 Other Indirect Effects

EPA has examined a variety of secondary effects associated with renewable fuels including the impact on domestic livestock and rice methane with international agriculture inputs and emissions, livestock, rice methane, and land use change. LUC impacts include an assessment of the economic indirect impacts of agricultural commodities which are addressed by FASOM and FAPRI. However, a variety of other indirect effects are not examined in the DRIA. First order approximations of some of these effects are straightforward while others require more subtle economic modeling.

The DRIA shows how the system boundaries are applied to agricultural products. The diagram does not reflect that the economic analysis applies only to some aspects of the life cycle – crop and land equilibrium. It does not apply to fossil energy carriers or choice of land type among countries where growth in agriculture is predicted. Table 2.26 summarizes our comments on EPA's approach to addressing other indirect effects associated with renewable fuels use.

EPA's economic analysis is applied to a limited component of life cycle analysis: land use and biofuels co-products. In principle, all of the components of the energy system are affected by the supply and demand of feedstocks. Other economic effects include:

- Ethanol supply on gasoline price and demand (rebound effect to be addressed by EPA with National Energy Modeling System (NEMS) analysis
- Ethanol plant natural gas consumption and natural gas prices
- Natural gas demand and LNG imports
- Agricultural commodities, LNG demand, fuel demand, and bunker fuel prices
- Selection of converted lands by region (in the EPA analysis, this is estimated in proportion to historical trends rather than a supply/demand analysis)
- Permanent construction of forest roads due to agricultural expansion
- Transportation distance and marketing logistics (for example, shipping soybeans from the U.S. to China vs. Brazil to China)
- Transportation mode (rail infrastructure vs. rural roads)
- Transport of agricultural inputs and distribution of agricultural products (the U.S. agriculture system has a very well-developed rail system where Brazilian products are often shipped by truck)
- The end use of agricultural products (soybeans from Brazil to China for example.

Table 2.26. Comments on EPA's Approach to Addressing Renewable Fuels Use

Parameter	EPA Approach	Comment
Rebound effect (Surplus fuel price rationing)	Use NEMS to assess additional driving due to fuel price impacts	An energy sector model would be appropriate for this impact.
Change in fuel and agriculture transport logistics	Not considered	Significant changes in fuel and agricultural commodity transport logistics will occur.
International crop inputs	FAOSTAT land area data (because FAPRI does not do this) and IEA data for international emissions from fertilizer inputs	Confusing as DRIA refers to data from ‗GREET mixed with' FAPRI and FAO coupled and IEA to formulate final calculation; EPA notes ‗further work' needed to calculate fertilizer use change as yields increase
Livestock emissions	FASOM for domestic and FAPRI for international livestock, using 2001 EPA GHG emission inventory report for 1990-2003	Domestic emission decrease is well represented based on decrease in livestock production; international increase is based the calculated livestock production response to price changes in FAPRI. FAPRI does not model GHG emissions, so IPCC emission factors used. IPCC emission factors should be rigorously compared to GHG results generated by FASOM. The effect of pasture and dairy intensification should also be examined.
Rice cultivation methane	FASOM for domestic and FAPRI for international rice methane, using IPCC emission factors	Domestic emission credit balances international rice methane emissions. International impacts are based on modeled changes in domestic exports; international increases in rice methane are reasonable if predicted share of export corn diverted to domestic ethanol is accurate. FASOM and FAPRI predict different export response, indicating the need to align models.
Change in fertilizer feedstock	Not considered	Increased crop production will increase use of coal-based nitrogen fertilizer. The growth in coal-based fertilizer may be an indirect effect that does not apply to U.S. crops.

2.7.6.1 Modeling Infrastructure Changes

EPA doesn't include the energy or emissions associated with producing the infrastructure for biofuels and petroleum production in its LCA, stating that the net effect of including these quantities would be a slight increase in the life cycle emissions for both the ethanol and petroleum fuels, and a negligible effect on the comparison (EPA 2009, p. 300). This justification, however, is a holdover from RFS1, which relied on attributional LCA. In a consequential LCA, what matters is the change in infrastructure between the baseline and the ―with biofuel" cases. Under this framing, the infrastructure for the additional ethanol would count against the ethanol, but there would be a decline in petroleum use, not an expansion. So, to the extent that there is a change in infrastructure, (e.g. marginally slower expansion of petroleum infrastructure in the biofuel case), this would also reduce the overall benefit of the biofuels. In the consequential analysis, these changes accumulate rather than cancel. Surely this effect is still small, but as EPA notes, this could reduce the GHG benefits of corn ethanol in comparison to gasoline by about 1% (p. 300), and the rationale for excluding it is incorrect.

2.7.6.2 Indirect Effect Recommendations

Other real and significant impacts should also be examined. These include:

- Transport logistics for fuels and agricultural commodities
- Fertilizer feedstocks
- Use of natural gas for ethanol plants and oil refining
- Other fuel production inputs

Indirect international impacts need further analysis in the following areas:

- Align FAPRI and FASOM models, including commodity export response to biofuel production
- Compare and assess the FASOM GHG calculation method with the international approach, using FAPRI with EPA data and IPCC emission factors

The NEMS model will likely not capture all of the indirect effects associated with the production of renewable fuels. The first step would be to calculate the direct impacts at the margin. The next would be to calculate coal based fertilizer production using GREET and examine the magnitude of other impacts.

2.7.7 Uncertainty and Sensitivity Analysis

Varying degrees of confidence in the different models EPA used as they focus on key parameters such as ‗land clearing,' their satellite analysis, and their sensitivity analysis, prompted the Agency to narrow the uncertainty of their approach by quantifying the overall ‗concerns' for the final rule. Then more ‗formal' uncertainty analyses will be included in the final rule.

EPA performs six sensitivity analyses associated with land conversion after concluding that LUC is one such issue that is highly debatable:

- **Types of Land Converted to Cropland Sensitivity Analysis** (using MODIS satellite data). Sensitivity analysis was conducted to address uncertainty by varying the types of land cleared for biofuel production. All governments claim land is _idle‘ and _un-used‘ which is far from the truth in the tropics.
- **Forgone Forest Sequestration Sensitivity Analysis.** Using 2006 GL AFOLU data the main EPA assumes 80 years of foregone forest carbon sequestration and the sensitivity analysis examines the results for different timeframes for foregone sequestration
- **Soil Carbon Emissions Sensitivity Analysis.** Based on feedback from stakeholders that soil carbon emissions can occur more rapidly than 20 years, EPA assessed the impact of the timing of soil carbon release on life cycle GHG emissions by calculating results assuming immediate release.
- **Pasture Replacement Sensitivity Analysis.** EPA considered a scenario where all new crop cultivation occurs on idle grassland, rather than converted pastureland. This assumption leads to dramatic reductions in GHG emissions associated with cropland expansion.
- **Year of Analysis Sensitivity Results**. In the analyses for 2012 and 2017 (in addition to EISA 2022), EPA notes that perhaps more land going into production for biofuels would cancel out the _benefit‘ of higher yields for corn, for example. EPA noted the 2012 and 2017 results _had‘ to include 2022 parameters for SOC in FASOM (but the Agency noted for the final rule, FASOM will be updated to allow for 2012 and 2017 estimates).
- **Fuel Volumes Modeled Sensitivity Analysis.** EPA considered sensitivity cases where the incremental impact of each biofuel (biodiesel, corn ethanol, stover ethanol and switch grass ethanol) was considered separately in 2022. GHG emissions were estimated for a marginal increase in fuel production.

As discussed below, the treatment of uncertainty in the RIA fails to meet the agency‘s own internal (draft) guidelines (Pascual, et al. 2003), the recommendations of EPA‘s Science Advisory Board (EPA Science Advisory Board 2006) and those of the National Research Council (NRC 2007).

EPA‘s draft guidance on the use of environmental models indicates:

"This Guidance recommends best practices to help determine when a model, despite its uncertainties, can be appropriately used to inform a decision. Specifically, it recommends that model developers and users: (a) subject their model to credible, objective peer review; (b) assess the quality of the data they use; (c) corroborate their model by evaluating the degree to which it corresponds to the system being modeled; and (d) perform sensitivity and uncertainty analyses. Sensitivity analysis evaluates the effect of changes in input values or assumptions on a model's results. Uncertainty analysis investigates the effects of lack of knowledge and other potential sources of error in the model (e.g., the "uncertainty" associated with model parameter values)

and when conducted in combination with sensitivity analysis allows a model user to be more informed about the confidence that can be placed in model results. A model's quality to support a decision becomes known when information is available to assess these factors." (Pascual, Stiber et al. 2003). NRC notes that besides a Regulatory Impact Analysis (RIA) for rules exceeding $100 million in economic effects, "rules exceeding $1 billion per year in economic effects are subject to a further requirement to include a formal analysis of uncertainty." (NRC 2007, p. 68). Although the guidance documents assume a context in which a decision is based in whole or part on model output, this guidance applies equally well to modeling for the RFS in which a performance measure is estimated by the models.

In the DRIA (p. 304), EPA explains its approach as follows:

"There are several ways of specifically dealing with uncertainty in this analysis. One approach would be to perform statistical analysis, applying distribution curves to each input and running Monte Carlo analysis to determine a range of results. While this may be the most intellectually pleasing approach in theory, there are several significant barriers to this approach. Most significantly, it is difficult to determine scientifically-defensible probability distribution functions for all (or even the most significant) input variables. Applying functions that are not well understood may serve to misstate uncertainty. Furthermore, an analysis that treats all variables independently would not capture the fact that there are links between inputs with potentially conflicting impacts on results (e.g., higher fertilizer use linked to higher crop yields). To do this correctly, we need to determine the covariance matrix of all variables, or risk further obscuring the degree of true uncertainty in the analysis."

While the difficulty in performing uncertainly analysis is well understood, a lack of data to support probability distribution functions does eliminate the possibly of performing a useful analysis. In fact scientists and engineers have been performing uncertainty analyses for centuries before Monte Carlo simulation software or even computers were available. It is (almost always) difficult to produce scientifically credible probability distributions for all significant input variables. Many studies resort to expert elicitation to estimate probability distributions. It is also correct that parameter correlations must be included to correctly characterize uncertainty. However, despite the challenges, EPA could do much more to quantify the uncertainty in its modeling results.

In a study by Resources for the Future—commissioned by EPA—Krupnick, et al. 2006, (p. 7) writes:

"Overall, there is a tendency to avoid formal uncertainty analyses unless the uncertainties can be included comprehensively and quantified precisely. An alternative—arguably, preferred— approach would be to conduct uncertainty analysis as best as possible, even if abilities are limited; almost any uncertainty analysis is better than none at all."

Two key distinct, though related, uncertainty analyses that can be performed:

1. Uncertainty importance analysis (global sensitivity analysis) identifies which parameters are important contributors to the uncertainty in model outputs. This analysis doesn't require precise distributions since the results are essentially qualitative: a list of the key factors and their relative contribution to uncertainty.
2. Uncertainty propagation characterizes the overall uncertainty in model outputs, given the uncertainties in model inputs. An accurate assessment does require accurate input probability distributions and parameter correlations, but these are not required to estimate the order of magnitude of the uncertainty in the result. Moreover, sensitivity analysis can be performed on the key distributions and parameter correlations identified in the uncertainty importance analysis, to bound the range of results for the output probability distributions.

In its Notice of Proposed Rulemaking (NPRM) and DRIA, EPA has failed to address 1 and has largely avoided 2, opting instead for a one-at-a-time sensitivity analysis.

2.7.7.1 Sensitivity Analysis – Local versus Global

EPA's sensitivity analysis examines the effect on model results of perturbations in individual model parameters, e.g. higher and lower yield, year of analysis, assumptions about pasture replacement, years of foregone sequestration, fuel volumes, etc. Since parameters are perturbed one-by-one, this is a ―local‖ analysis, i.e. it doesn't consider the impact of multiple, simultaneous parameter perturbations. One-at-a-time (OAT) analysis fails to account for the many interactions between model parameters in non-linear models such as these. Despite its widespread use, OAT sensitivity analysis has been called ―illicit and unjustified‖ for all but strictly linear models (Saltelli, et al. 2006).

In contrast, uncertainty importance analysis examines the contribution of individual parameters to the overall uncertainty in the model output. A common global sensitivity analysis technique (supported in Crystal Ball® for example) is to run a Monte Carlo analysis, and report the rank correlations between input parameters and output parameters across the full range of input values selected in the simulation.

The most significant challenge in analyzing uncertainty in EPA's modeling system is the impracticality of running a full Monte Carlo analysis across the many models involved. These models are presumably ―soft-linked.‖ This means that running the full suite of models requires human intervention, and the full modeling system probably involves long enough run times to preclude the large number of runs required for a Monte Carlo analysis, even assuming the use of more efficient methods such as Latin Hypercube Sampling (McKay, et al. 1979).

2.7.7.2 Uncertainty Analysis Recommendations

- Where practicable, EPA should perform uncertainty importance analysis on its full model, or on individual sub-models, to identify and quantify as well as possible the key uncertainties.

- EPA should fully document the range of parameter and model uncertainties in each model component. This is especially important where quantitative assessment is deemed too difficult.

2.7.8 Documentation and LCA Procedures

EPA's analysis includes a complex layering of agricultural and life cycle models. A significant amount of additional documentation will be necessary to assure a transparent analysis and to answer key questions such as the following:

- Does the analysis use comparable life cycle impacts for fertilizers and fuels in the U.S. and outside of the U.S.?
- Are likely international crop yields, agricultural inputs, transportation modes and marketing distance taken into account?
- Are price elasticity factors applied consistently within the models?
- What are the likely ranges in estimates based on a sensitivity analysis that reflects the uncertainty in key parameters and inputs?
- Even though the DRIA is over 800 pages long only 300 pages address the LCA issue. EPA could do much more to document the life cycle analysis inputs and intermediate results. For example the life cycle data in FASOM are not compared with GREET data. Such comparisons are straightforward for the model developers, and should be done. FASOM and GREET agricultural chemical and fuel inputs can be compared on g/bu, g/ton, or g/acre basis and give intermediate results in g CO_2e/bu or g CO_2e/ton.

An overall comment on EPA's analysis of the RFS is that it perhaps follows more of a regulatory impact analysis, rather than a life cycle assessment. Thus, the analysis in EPA's DRIA should be considered to be an abbreviated LCA conducted mostly outside of the ISO framework. A discussion on how EPA's analysis conforms to the ISO standards for environmental LCAs is given in Appendix B.

The DRIA states that the goal of the lifecycle analysis is to ―…determine the GHG emissions and fossil fuel impact of the increased use of renewable fuels.‖ Rather than comparing two product systems that produce the same functional unit (e.g., combustion of one million Btus of transportation fuel), the EPA analysis compares future scenarios for increased use of renewable fuels with a reference case of renewable fuel use at current levels. The goals statement does not define what these current levels and future scenarios are, however.

The goal description in the DRIA does not state who the intended audience of the lifecycle assessment is or whether the results will be used in comparative assertions that are made public. Presumably, the audience is the general public, as well as policy makers, and comparative assertions are implicit in the goal of the work. These points are important because they lead to the additional requirements for comparative LCAs that are made public.

The DRIA describes the product systems to be studied as conventional and alternative fuels on a well-to-wheels basis from the acquisition of raw materials through the use of the fuels in motor

vehicles. It does not clearly define a functional unit, however, on which to compare the fuels on a common basis. Such a metric might be a given higher heating value (HHV) of fuel combusted, or a given distance traveled in a particular type of vehicle. Instead, the system appears to be the well to tank emissions of GHGs per unit of fuel, with the assumption that the amount of fuel and the non-CO_2 GHG emissions during use are the same for conventional and renewable fuels, and that the same fraction of carbon is oxidized to CO_2 during the use of the fuels.

The DRIA describes the system boundary and notes that emissions associated with international land use changes are not included within the scope of the LCA due to limitations in modeling capabilities. While it notes this as a shortcoming, it does not (and cannot) quantify the effects on the results.

The DRIA does not describe any cut-off criteria for the inclusion of inputs and outputs. As noted in Appendix B, the ISO standard requires that this cutoff be clearly described. When assessing the upstream GHG emissions associated with the production of a fuel, for example, this would mean setting some criterion for inclusion of GHG emissions in the lifecycle accounting and consistently applying this criterion.

Another key omission in the RIA is a discussion of the critical review for the study. Under ISO 14044, a critical review is a requirement for this sort of public analysis of product options, yet it is not discussed in this chapter.

2.7.8.1   Guidance on the Use of Models in Environmental Regulatory Decision-Making

EPA established the Council for Regulatory Environmental Modeling (CREM) in 2000 to improve and support the use of models at the agency. Three guidance documents about the development, evaluation, and application of environmental models stem from work by or commissioned by the CREM (NRC 2007, EPA Science Advisory Board 2006, Pascual, et al. 2003). These documents describe the complexities and importance of testing and documenting models, ensuring transparency, quantifying and reporting uncertainty, and reviewing models specifically in the context for which the Agency is applying them. A summary of EPA and other modeling recommendations and a discussion of how these were applied in developing the NPRM is given in Appendix C. Unfortunately, the NPRM and the DRIA fail to meet many of these recommendations. Several of the models EPA used have little or no documentation (FASOM, FAPRI, GREET, custom ASPEN configurations). As discussed above, very little actual uncertainty analysis has been done due to the difficulties involved and OAT sensitivity analysis has been used to estimate uncertainty instead. Transparency is lacking because EPA has not provided input values or intermediate calculations, and the configured models have not been independently reviewed. Many factors need to be considered, the assumptions of the many models used must be aligned to maintain a consistent modeling framework, and EPA should adhere to the CREM guidelines to ensure the highest quality modeling effort.

2.7.8.2   Documentation Recommendations

EPA has combined a regulatory impact analysis with a partial documentation of life cycle analysis modeling. More could be done to improve the usability of the documentation.

Documentation of the impacts of renewable fuels should follow the framework of the ISO standards for life cycle analysis. Such an effort cannot be accomplished quickly. There are many models, integration, and reporting issues.

EPA should also consider an ongoing effort to document life cycle analysis inputs outside of a regulatory environment.

2.7.9 Approach General Issues

A variety of other comments were identified as part of the review. These are presented here

- System Boundary diagrams are incomplete. They do not reflect the fate of products and co-products for each fuel technology. Fuel is combusted, yielding CO_2 according to the fuel carbon content and CH_4 and N_2O emissions, based on specific vehicle. The important factors of co-product treatment in the system boundary are the product displaced, the co-product, the co-product analysis method (allocation or displacement), the metric used to compare products (i.e., energy content, calories, protein content), and the final fate of the co-product considered (i.e., digestion, landfill, combustion).

- EPA recognizes the need to expand the consequential LCA to other energy sectors (presumably fuel switching for electric power, fertilizers, natural gas resources, competition for biomass feedstock from biomass power). EPA plans to use NEMS to provide this analysis but it is not clear that NEMS is configured for these scenarios or that NEMS would take into account international impacts such as shifts in fertilizer feedstocks. Coal-based fertilizer and chemical production has increased significantly in recent years, with a corresponding increase in life cycle emissions, and is likely to increase in the future. EPA should consider important global shifts in commodity production in the RFS2.

- FASOM/FAPRI systems are based on historical behavior and equilibrium price behavior. The analysis omits the effect of real market prices, which can often be higher than equilibrium predictions. Additionally, FASOM and FAPRI need to be aligned.

- The DRIA claims to use GREET to determine inputs for international agriculture (EPA 2009, p 645). It is unclear if new GREET model inputs will be developed, or whether new GREET analyses will performed to represent the ―international‖ data.

- Soil carbon release data is based on analysis by Winrock International (Harris, et al. 2008). Winrock performed an analysis based on MODIS satellite data to identify the agricultural frontier in each region, and then relied on the IPCC‗s GHG inventory guidelines to estimate emissions from land use changes. However, while Winrock (Harris, et al. 2008) used the IPCC‗s equations and parameters, they ignored an important aspect of the IPCC methodology: the IPCC treats uncertainty as a central element of these analyses, reporting error ranges for all parameters and including in each section of the guidelines a thorough discussion of uncertainty.

2.8   Biofuels References

Aden, A. et al. (2002) Lignocellulosic Biomass to Ethanol Process Design and Economics Utilizing Co-Current Dilute Acid Prehydrolysis and Enzymatic Hydrolysis For Corn Stover. NREL Report No. TP-510-32438, June 2002. http://www.nrel.gov/docs/fy02osti/32438.pdf.

ARB (2008). Staff Report: Proposed Regulation to Implement the Low Carbon Fuel Standard - Initial Statement of Reasons (ISOR). California Air Resources Board.

ARB (2008b). Detailed California-Modified GREET Pathway for Corn Ethanol. Version 2.1. Stationary Source Division. Release Date: February 27, 2009.

Bouwman, A., et al. (2002a). Emissions of N_2O and NO from Fertilized Fields: Summary of Available Measurement Data. Global Biogeochemical Cycles **16**(4): 1058.

Brinkman, N., et al. (2005). Well-to-Wheels Analysis of Advanced Fuel/Vehicle Systems -- A North American Study of Energy Use, Greenhouse Gas Emissions, and Criteria Pollutant Emissions. General Motors and Argonne National Laboratory.

CalEPA (2005). Hydrogen Highway Blueprint Plan. California Environmental Protection Agency.

CONCAWE (2007). Well-to-Wheels Analysis of Future Automotive Fuels and Powertrains in the European Context." EUCAR/JRC/CONCAWE.

Cruse R.M., and C.G. Herndl (2009), Balancing Corn Stover Harvest for Biofuels with Soil and Water Conservation. Journal of Soil and Water Conservation. 64(4):286-291.

Crutzen, P., et al. (2007). "N_2O release from Agro-biofuel Production Negates Global Warming Reduction by Replacing Fossil Fuels. Atmospheric Chemistry and Physics Discussion **7**: 11191-11205.

Delucchi, M. (2006). Lifecycle Analysis of Biofuels, draft report. Institute of Transportation Studies, University of California, Davis.

DOE. (2006). Potential Roles of Ammonia in a Hydrogen Economy. from www.DOE.gov.

DOE (2010). Energy Information Agency, Natural Gas Navigator, March 29, 2010. http://tonto.eia.doe.gov/dnav/ng/ng_pri_sum_dcu_nus_m.htm.

Edwards, R., et al. (2008). Well-to-Wheels Analysis of Future Automotive Fuels and Powertrains in the European Context: Well-to-Tank Report, Version 3. EUCAR, CONCAWE, and JRC/IES.

Edwards, R., et al. (2006). Well-to-wheels Analysis of Future Automotive Fuels and Powertrains in the European Context: Well-to-Tank Report, Version 2b. EUCAR, CONCAWE, and JRC/IES.

Egli, D. (2008). Soybean Yield Trends from 1972 to 2003 in Mid-western USA. Field Crops Research 106: 53-59.

EPA (2009) Draft Regulatory Impact Analysis: Changes to Renewable Fuel Standard Program, EPA-420-D-09-001 May 2009

EPA Science Advisory Board (2006), Review of Agency Draft Guidance on the Development, Evaluation, and Application of Regulatory Environmental Models and Models Knowledge Base.

Garthwaite, J. (2009). Cello Energy Leaves 50M-Gallon Gap in Feds' Ethanol Targets. http://earth2tech.com, Accessed September 2009.

Harris, N., S. Grimland and S. Brown. (2008). GHG Emission Factors for Different Land-use Transitions in Selected Countries/Regions of the World. Report submitted to EPA, October 2008.

Heatherly, L., and Elmore, R. (2004). Managing Inputs for Peak Production Soybeans: Improvement, Production, and Uses. ASA-CSSA-SSAJ**:** 451-536.

Hill, J., et al. (2006). Environmental, Economic, and Energetic Costs and Benefits of Biodiesel and Ethanol Biofuels. Proceedings of the National Academy of Sciences 103(30): 11206-11210.

Houghton, R. A. and J. L. Hackler (1999). Emissions of Carbon from Forestry and Land-use Change in Tropical Asia. Global Change Biology 5(4): 481-492.

IFA-FAO (2001). Global Estimates of Gaseous Emissions of NH_3, NO and N_2O from Agricultural Land. International Fertilizer Industry Association, Food and Agriculture Organization of U.S.

IFA (2009). Fertilizers, Climate Change and Enhancing Agricultural Productivity Sustainably. White Paper, www.fertlizer.org.

IPCC (2001). Good Practice Guidance and Uncertainty Management in National Greenhouse Gas Inventories. The Intergovernmental Panel on Climate Change.

IPCC (2006), 2006 IPCC Guidelines for National Greenhouse Gas Inventories, Volume 4, Agriculture, Forestry and Other Land Use, IGES, Japan. http://www.ipcc-nggip.iges.or.jp/public/2006gl/vol4.html.

IPCC (2007). Fourth Assessment Report: The Physical Science Basis. Available at: http://www.ipcc.ch/.

IPCC (2009). Available at http://www.ipcc-nggip.iges.or.jp/public/gpglulucf/gpglulucf.htm.

Johnson, R., (1987). Management. Soybeans: Improvement, Production, and Uses. J. Wilcox. ASA-CSSA-SSAJ**:** 355-390.

Johnson, W., et al. (2007). Influence of Nitrogen Application Timing on Low Density Giant Ragweed (Ambrosia trifida) Interference with Corn. Weed Technology 21: 763-767.

Krupnick, A., et al. (2006). Not a Sure Thing: Making Regulatory Choices under Uncertainty., Resources for the Future.

Larivé, J-F (2008). Fuels Life Cycle Issues in Generic Studies and within a Regulatory Framework, The European Experience. CONCAWE Presentation at CA Biomass Collaborative.

Leão de Sousa, E. (2009). The Sugar-energy Industry and the Challenges of the Carbon Market. Accessed at http://english.unica.com.br, Accessed September 2009.

Lindemann, W. and Glover, C. (2003). Nitrogen Fixation by Legumes. G. A-129 New Mexico State University.

Lupwayi, N. and Kennedy, A. (2007). Impacts on Selected Biological Soil Processes. Agronomy Journal 99: 1700-1709.

Macedo, I. and J. Seabra (2008). Mitigation of GHG Emissions Using Sugarcane Bioethanol. Sugarcane Ethanol: Contributions to Climate Change and the Environment. P. Zuurbier and J. Vooren.

McKay, M., et al. (1979). A Comparison of Three Methods for Selecting Values of Input Variables in the Analysis of Output from a Computer Code. Technometrics 21(2): 230-245.

Mehdi, B, et al. (1999). Yield and Nitrogen Content of Corn under Different Tillage Practices. Agronomy Journal 91: 631-636.

Murty, D., M. U. F. et al. (2002), Does Conversion of Forest to Agricultural Land Change Soil Carbon and Nitrogen? A Review of the Literature. Global Change Biology 8(2): 105-123.

National Biodiesel Board. (2007, April 26, 2007). Biodiesel Production and Quality. Retrieved November 3, 2007, from http://www.biodiesel.org/pdf_files/fuelfactsheets/prod_quality.pdf.

NRC (2007). Models in Environmental Regulatory Decision Making, Committee on Models in the Regulatory Decision Process of the National Research Council.

O'Conner, D. (2005) Documentation for Natural Resources Canada's GHGenius Model 3.0, prepared for Natural Resources Canada, Ottawa, Ontario by (S&T)[2] Consultants.

Pascual, P., N. Stiber, and E. Sunderland (2003), Draft Guidance on the Development, Evaluation, and Application of Regulatory Environmental Models., U.S. Environmental Protection Agency, Council on Regulatory Environmental Models.

Payraudeau, S., et al. (2007). Analysis of the Uncertainty Associated with the Estimation of Nitrogen Losses from Farming Systems. Agricultural Systems 94(2): 416-430.

Pimentel, D. and Patzek, T. (2005). Ethanol Production Using Corn, Switchgrass, and Wood; Biodiesel Production Using Soybean and Sunflower. Natural Resources Research 14(1): 65-76.

Phillips, S. et al. (2007) Thermochemical Ethanol via Indirect Gasification and Mixed Alcohol Synthesis of Lignocellulosic Biomass. NREL Report No. TP-510-41168, April 2007. http://www.nrel.gov/docs/fy07osti/41168.pdf

Plevin, R. J. (2009) Modeling Corn Ethanol and Climate: A Critical Comparison of the BESS and GREET Models. Journal of Industrial Ecology 13(4).

Pont, J., (2007). "Full Fuel Cycle Assessment, Well to Wheels Energy Inputs, Emissions, and Water Impacts." California Energy Commission.

Prince, A. (2007). Initiating New Projects in Ammonia Sector. from www.fertilizer.org.

Rochette, P., et al. (2008). Nitrous Oxide Emissions Respond Differently to No-Till in a Loam and a Heavy Clay Soil. Soil Sci Soc Am J 72:1363-1369.

Rochette, P., et al. (2004). Emissions of N_2O from Alfalfa and Soybean Crops in Eastern Canada." Soil Sci Soc Am J 68: 493-506.

Saltelli, et al. (2006).

Sheehan, J., et al. (1998). An Overview of Biodiesel and Petroleum Diesel Life Cycles." NREL report, NREL/TP-580-24772.

Sheehan, J., et al. (1998). Life Cycle Inventory of Biodiesel and Petroleum Diesel for use in an Urban Bus. U.S. Department of Agriculture and U.S. Department of Energy.

Sinclair, T., et al. (2003). Modeling Nitrogen Accumulation and Use by Soybean." Field Crops Research 81(2-3): 149-158.

Stehfest, E. and Bouwman, L. (2006). N_2O and NO Emission from Agricultural Fields and Soils under Natural Vegetation: Summarizing Available Measurement Data and Modeling of Global Annual Emissions. Nutrient Cycling in Agroecosystems 74: 207-228.

Tao, L. and A. Aden (2008) Technoeconomic Modeling to Support the EPA Notice of Proposed Rulemaking (NOPR) NREL Memorandum on Process Analysis, November 3, 2008

Unnasch, S. and Pont, J. (2007). Full Fuel Cycle Assessment: Well to Tank Energy Inputs, Emissions and Water Impacts. CEC Report CEC -600-2007-004D, February 2007.

USDA (2007). Agricultural Chemical Usage 2006 Field Crops Summary. February 5, 2008, Retrieved from http://www.nass.usda.gov/QuickStats/index2.jsp.

USDOE (2007). Biomass Feedstock Composition and Property Database. February 5, 2008, Retrieved , from http://www1.eere.energy.gov/biomass/feedstock_databases.html.

Wagner-Riddle, C., et al. (2008) Linking Nitrous Oxide Flux During Spring Thaw to Denitrification in the Soil Profile. Soil Sci Soc Am J 72:908-926.

Wang, M., (1999). GREET 1.5--Transportation Fuel Cycle Model, Volume 2: Appendices of Data and Results.

Wang. M., (2007). GREET Model 1.8a. Retrieved from http://www.transportation.anl.gov/software/GREET/.

Wang, M., et al. (1999). Effects of Fuel Ethanol Use on Fuel-Cycle Energy and Greenhouse Gas Emissions. Center for Transportation Research, Energy Systems Division, Argonne National Laboratory.

Wang, M., (1999). GREET 1.5 — Transportation Fuel-Cycle Model, Volume 1: Methodology, Development, Use, and Results. Center for Transportation Research, Energy Systems Division, Argonne National Laboratory.

Wilhelm, W. W., et al. (2007), Corn Stover to Sustain Soil Organic Carbon Further Constrains Biomass Supply, Agron. J. 99:1665–1667..

Zuurbier P., et al., Ed. (2008). Sugarcane Ethanol: Contributions to Climate Change Mitigation and the Environment. The Netherlands, Wageningen Academic Publishers.

3   Review of Petroleum Fuel Pathways

The assessment of emissions and energy consumption associated with the use of transportation fuels requires that the entire fuel cycle be considered, from the extraction of raw materials to the use of the final product. Fuel cycle analysis is complex. Data for conducting such analyses are often not well established or have a large degree of uncertainty. Nevertheless, the Energy Independence and Security Act (EISA) of 2007 requires that fuel cycle analyses be conducted as part of the development of regulations on the use of renewable transportation fuels. Therefore, both petroleum fuel and non-petroleum pathways need to be examined. In this section, we examine how EPA analyzed petroleum fuels pathways in its Draft Regulatory Impact Analysis (DRIA) for the proposed changes to the renewable fuel standard program, which result from the passage of EISA.

3.1   Petroleum Fuels Life Cycle Modeling

The petroleum fuel cycle includes energy inputs and emissions related to the production of crude oil, transport of crude oil to refineries, refining of the oil, and distribution of the finished products as illustrated in Figure 3.1. The fuel cycle analysis takes into account energy inputs, emissions, and losses associated with each step in the petroleum production process. Losses in the fuel cycle are accounted for by applying a loss factor to the amount of upstream energy used.[9]
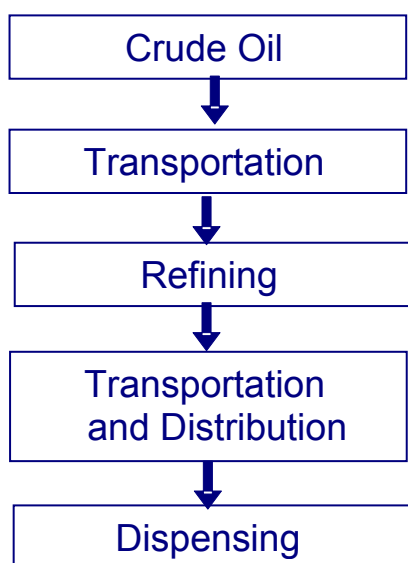

Figure 3.1. Steps in the petroleum fuel cycle

---

[9] Note that the GREET model only applies the loss factors for fuel cycle activities to the transportation, storage, and distribution activities of the well-to-tank portion of the fuel cycle for petroleum fuels. We are also reviewing how the loss factors are applied to other fuels.

In this section, we are primarily concerned with the crude oil recovery and refining steps as they require the greatest amount of energy. The energy required for transportation, distribution, and dispensing is much less. And while hydrocarbon losses during these steps may be of concern when assessing criteria pollutant emissions, they are generally not considered to be significant sources of GHG emissions. This is so because gasoline and diesel fuel contain negligible quantities of methane and other GHGs.

The GREET model used by EPA for the DRIA calculates the emissions associated with each step of the fuel cycle based on the energy efficiency that is input for each step. These efficiency figures are based on the amount of energy required to conduct the step in the process plus the energy in the fuel itself. The model contains default values for the energy efficiencies based on information gathered from other publications. Typically these data come from aggregate data for the industry. While the efficiency figures are inputs that can be changed by the user, in most cases, users rely on the defaults. This is the approach taken by EPA in the development of regulations under EISA.

The use of an efficiency metric for each step in the fuel cycle deserves further explanation as it is key to understanding how GREET calculates fuel cycle GHG emissions. As described in Loreti and Murphy (2005), the overall efficiency for each step of transportation fuel production is defined in the GREET model as:

$$Overall\,Efficiency = \frac{Energy\,Output}{Energy\,Output + Energy\,Input}$$

where:

Overall Efficiency = ratio of energy efficiency of the production process
Energy Output = energy embodied in the output of the process
Energy Input = energy consumed in the production process step

This formulation is used for each step in the production process up to the point of use to account for the life cycle energy consumption for the fuels. The energy consumption values are then distributed among the various fuels that provide the energy to calculate the GHG emissions for each productions step. Where additional GHG emissions occur that are not accounted for in the energy inputs to the process, they are added to the energy-related GHG emission for the production step.

While the GREET approach is conceptually sound, its ability to accurately model the production of U.S. transportation fuels in both the present and the future depends on the accuracy of the assumptions the user selects in running the model, and in the representativeness of the data built into the model. This is true for both for the production of crude oil and the refining of it into gasoline and diesel fuel. In the sections that follow, EPA's approach to using GREET are discussed first, followed by a discussion of how the GREET model calculates emissions from the production and refining of crude oil.

3.2 EPA's Approach to Assessing Fuel Cycle GHG Emissions from Petroleum Fuels under EISA

The approach EPA used to assess life cycle GHG emissions from petroleum fuels under EISA is to some extent defined by the law itself. The law includes such specific requirements as setting the year 2005 as the baseline for petroleum fuels and requiring the analysis of full life cycle emissions, including significant indirect GHG emissions, such as those resulting from land use change. Other aspects of the approach are left up to EPA, however.

As noted in Section 1.2, in February 2008, EPA shared with API an update on how it planned to analyze life cycle GHG emissions under EISA (EPA 2008). As it has done in previous fuel cycle analyses, EPA employed the GREET model developed by Argonne National Laboratory (Wang 2008). For this work the Agency used Version 1.8 of the model[10].

3.2.1 EPA's Approach to Modeling Emissions from Crude Oil Production

The GREET model provides for three types of oil production: crude oil, oil sands recovery using surface mining, and oil sands recovery using in-situ production. In applying the GREET model for the EISA, EPA used U.S. Energy Administration data (EIA, 2007a) on the sources of crude oil refined in the U.S. in 2005. Our review of the crude oil import data for that year is consistent with EPA's data.

EPA places a lot of attention on imports of oil sands (also referred to as tar sands). In 2004, about 80% of total production of heavy oil and bitumen from Alberta was exported to the U.S., chiefly to PADD II, but with significant exports to PADD IV (e.g. two Suncor refineries in the Denver metro area, ACR 2004, Proctor 2005). Given 2005 tar sands production of 991,000 bbl/d (CAPP 2007), this suggests that approximately 793,000 bbl/d of tar sands products were imported into the United States in 2005. This figure is equal to approximately 5.2% of domestic crude oil consumption in 2005 (EIA 2007a). Thus, EPA's assumption that approximately 5% of U.S. crude oil consumption in 2005 was bitumen-based syncrude (primarily from Canada) appears reasonable.

For crude oil other than from oil sands, the GREET model assumes that energy intensity is the same for imported oil as for domestically produced oil. (As discussed below, the rate of flaring is assumed to be double for imported oil.) In applying the GREET model, EPA has adjusted the GHG emissions for the production of heavy oil and Venezuela extra heavy oil by applying scaling factors of 1.07 and 2.40, respectively, to the GREET GHG emissions for the production of conventional crude oil (up the point of transport to the refinery). EPA's basis for making these adjustments is questionable, however, for several reasons.

EPA did not use the emissions value for conventional oil in GREET to derive the scaling factors. Instead, it used an average of other imported oils from a paper by McGann and McGee (McGann and McGee 1999). Moreover, there is no supporting data for any of the emissions intensity

---

[10] At the time the draft regulations were being developed, GREET Version 1.8b, released July 25, 2008 was the most recent version, and thus was used for this analysis.

values in the original paper. The value for Venezuelan extra heavy oil is noted as being for oil that is partially upgraded. This same oil has lower refining emissions than any of the others reported in the paper (since some of the energy and emissions that would otherwise be associated with the refining step have already been accounted for). Thus, the scaling factor will tend to overstate the emissions for petroleum products made with this crude oil.

An additional problem with EPA's use of the scaling factor is that the GREET model already contains a scaling factor to account for additional flaring associated with imported oil. It appears that EPA has applied the scaling factors for heavy oil and extra heavy Venezuelan oil to the total GHG emissions for imported oil (including flaring and venting), and thus would be further increasing those emissions.

3.2.2 EPA's Approach to Modeling Emissions from Oil Refining

EPA considered three types of gasoline used in 2005 to establish the baseline for the draft RIA. The three types are conventional gasoline, reformulated gasoline, and California reformulated gasoline. EPA based the proportion of each type of gasoline on data from the EIA. It did not, however, use the most appropriate data series, and as a result overstates the proportion of gasoline sales that were reformulated gasoline in 2005.

Although EPA does not cite the specific data series in the DRIA, based on the values it modeled, the Agency apparently used EIA data on ―Refiner Sales to End Users‖ to calculate the proportions of each type of gasoline sold. Most refineries do not sell motor fuels directly to end users, however, and therefore the EPA data represent a relatively small fraction of total gasoline sales—59,000 thousand gallons/day as compared to 378,000 thousand gallons/day (EIA, 2006c). In addition, EPA added sales of oxygenated gasoline to those for reformulated gasoline even though EIA explicitly defines oxygenated gasoline as not being reformulated. Therefore it should have added the oxygenated gasoline to the conventional gasoline figure instead of the reformulated gasoline figure.

The more appropriate EIA gasoline sales data for 2005 are ‖Prime Supplier Sales‖ volumes.

Table **3.1** compares those data with the data used by EPA in the draft RIA and the resulting proportions of each type of gasoline produced. Using the correct data, the proportion of conventional gasoline sold in 2005 amounts to 66.1% versus 57.4% used by EPA for the draft RIA. Federal reformulated gasoline is 22.4% versus the EPA calculated value of 28.4%, and the corresponding figures for California reformulated gasoline are 11.5 versus 14.2%.

Because reformulated gasoline takes more energy to produce than conventional gasoline, the energy and emissions calculated by EPA are greater than they would otherwise be if the appropriate mix of gasolines were modeled. The effect, however, is relatively modest. When GREET was re-run with the prime supplier data, total refinery GHG emissions for the gasoline mix was found to increase by 2.0% while total well-to-tank GHG emissions for the same mix increased by 1.3%.

Table 3.1. Comparison of 2005 EIA Gasoline Supplier Sales Data to Refiner Sales Data used by EPA in the Draft RIA

Gasoline Type	Prime Supplier Sales, thousand gallons/day	Percent of Total	Refiner Sales to End Users, thousand gallons/day	Percent of Total
Total	378,473	100	58,977	100
Conventional	237,648	62.8	33,846	57.4
Oxygenated	12,468	3.3	2,245	3.8
Conventional + Oxygenated	250,115	66.1	36,090	61.2
Total Reformulated	128,358	33.9	22,887	38.8
CA Reformulated	43,560	11.5	8,392	14.2
Reformulated w/o CA	84,798	22.4	14,495	28.4*

*Includes the 3.8% oxygenated as in EPA draft EIA.
 Source: EIA (2006c)

EPA‗s assumptions about diesel fuel supplied in the U.S. in 2005 are inconsistent with the EIA data, with much greater effects on estimated GHG emissions than those for gasoline. EPA assumes 100% low sulfur diesel fuel was sold in the U.S. in 2005. The definition of ―low-sulfur‖ in GREET is different from the EIA‗s definition, however, and thus EPA does not use the GREET model properly to model U.S. diesel consumption. The EIA data for 2005 indicate that more than 80% of diesel consumption was ―low-sulfur‖ with the remainder ―high-sulfur;‖ virtually none was ―ultra-low-sulfur.‖ The EIA definition of ―low-sulfur‖ is 15 to 500 ppm sulfur and ―ultra low-sulfur‖ diesel contains less than 15 ppm S (EIA 2006a). In the GREET model, however, ―low-sulfur‖ diesel is represented as having a sulfur content of 11 ppm. Thus ―low sulfur‖ in GREET corresponds to ―ultra low-sulfur‖ EIA data.

Since the EIA data indicates that there was negligible ultra low-sulfur diesel consumption in 2005, and a large fraction of the consumption was diesel with a sulfur content of 15-500 ppm, the EPA RIA should be based on conventional diesel in GREET, which is assumed to have a sulfur content of 200 ppm. EPA‗s selection of low-sulfur diesel as the baseline in GREET results in refinery energy consumption more than 11% greater than for the production of conventional diesel—119,821 vs. 107,420 Btu/Btu of fuel produced (both on an lower heating value basis). This assumption results in refinery GHG emissions that are overstated by approximately 11% and well-to-tank GHG emissions that are overstated by approximately 7%.

3.3   Uncertainties in Modeling Fuel Cycle GHG Emissions with GREET

The previous section described how EPA applied the GREET model in conducting its DRIA. The GREET model itself contains a large amount of data and makes a large number of assumptions related to the estimation of fuel cycle GHG emissions from petroleum fuels. In this section we discuss the uncertainties in emission estimates that result from the GREET model itself.

3.3.1   Conventional Crude Oil Production

In the GREET model, aggregate data are used to derive energy efficiency figures for process stages, which serve as default model inputs. In theory, a bottom up approach could be used to provide a more accurate assessment of the energy consumption and emissions at each process unit. As a practical matter, however, this would require aggregating energy and emissions data across thousands of oil producers, many of whom may not even estimate or measure such energy consumption or emissions. In the absence of detailed process level data that can be aggregated from producer energy and emissions inventories, we are left with the aggregate data to use, even though we recognized the limitations of its accuracy.

3.3.2   Energy Consumption in Conventional Oil Production

Energy inputs to conventional oil production vary with a number of characteristics. Field or reservoir characteristics, such as producing depth and reservoir permeability affect energy inputs. Production location also affects energy inputs in the transportation of the crude oil to refineries.[11] Characteristics of the produced fluids will also greatly affect energy inputs to production: the water cut, crude oil viscosity, concentration of trace contaminants, and hydrogen sulfide content of produced gas. Both field and fluid characteristics determine the production technology used, and therefore the energy inputs to oil production. Even if detailed field and fluid characteristics were available, moving from these data to LCA-based energy demand analysis for oil production would require an extensive inventory of oil production resources. Engineering analyses of energy demand are possible at the project level, but this type of analysis would not scale to the level of fuel cycle models.

Fuel-cycle models suffer from this lack of data on energy use in crude oil production. GREET cites five sources as the basis for its assumption of 98% efficient extraction of petroleum (Wang 1999, Table 4.3). No detail is given for how these sources were used, and these sources are generally difficult to obtain. A study by Delucchi cited by Wang reconstructs energy inputs to crude oil production by using aggregated national-level data from the 1987 Census of Mineral Industries (CMI) data (Delucchi 1991). These CMI data are also used by Cleveland (1991, 1992a, 1992b) in his historical analyses.

In the absence of other industry-wide data, it is useful to compare GREET values to values that can be generated from recent CMI data (see Table 3.2). This comparison shows that GREET estimates closely match the overall energy efficiency of domestic crude oil production calculated with the CMI data. The CMI data suggest that 20.1 kJ of energy are consumed per MJ of crude oil and natural gas produced, compared to about 20.4 kJ/MJ assumed in GREET. In both cases, the electricity energy consumption is expressed simply in terms of kilowatt-hours converted to kilojoules.

There is some disagreement with respect to fuel types consumed in production (Wang 1999, Table 4.4). GREET assumes a lesser share of natural gas (actually field gas plus natural gas)

---

[11] As an example of impact due to location, Alaskan crude will have larger pipeline energy consumption than crude from fields in the Los Angeles basin.

inputs to production (62% vs. 72%) and a greater share of diesel fuel consumed than found in CMI data (15% vs. 5%). Otherwise, the fuel shares match closely. No source is given in the GREET documentation for the fuel type breakdown, and the data may come from the same source.

Table 3.2. Energy Inputs to U.S. Crude Oil Production by Fuel Type, GREET 1.8 Model vs. Census of Mineral Industries National-Level Data

Process input	GREET 1.8		CMI 2002	
	Percent of Energy Input[a]	kJ/MJ of Crude Throughput[a]	Percent of Energy Input[b]	kJ/MJ of Crude Throughput[b]
Crude Oil	1	0.20	0.7	0.1
Residual Oil	1	0.20	-	-
Diesel	15	3.06	5.0	1.0
Gasoline	2	0.41	2.5	0.5
Natural Gas	61.9	12.6	72.4	14.6
Electricity	19	3.87	18.1[c,d]	3.6
Loss/other [e]	0.1	0.03	1.3	0.3
Total	**100**	**20.4**	**100**	**20.1**
Efficiency		**98.0%**		**97.9%**

a – Data from GREET version 1.8 (Wang 2007). Documented in GREET 1.5 documentation, Tables 4.3 and 4.4 (Wang 1999).

b – Data from US Census Bureau, 2002 Census of Mineral Industries (USADC 2004), for the oil and natural gas extraction industry. Data are averages for oil and natural gas production due to data aggregation.

c – Electricity consumption in kWh converted to Btus without considering the efficiency of conversion.

d – Electricity consumption does not include ―quantity of electricity generation less sold.‖ This is assumed to be self-generation of electricity consumed on site (e.g. electricity generation from co-generated steam for thermal-EOR production that is used on site, as described below). This electricity is assumed to be fueled with on-site natural gas or crude oil, which is already included in fuel consumed.

e – In GREET model this row represents fuel losses. In CMI, it represents two categories: ―other fuels‖ and ―undistributed fuels.‖ Other fuels described in CMI data as coke, LPG, wood, etc. These are reported as dollar values, and are converted to energy content assuming price equivalent of 40$/bblOE. Undistributed fuels were not specified. Dollar values converted to energy inputs assuming $/bblOE based on 2002 coal prices and energy densities (EIA 2007a).

The energy intensity of crude oil production in GREET comes from figures for average domestic production, and are the same as those used in GREET Version 1.5 (Wang, 1999). In addition to questions about the uncertainty of these numbers, the larger question of whether figures for domestic production apply to imports must also be considered. According to the EIA (2007a) in 2005, crude oil imports amounted to more than 66% of U.S. refinery inputs of crude oil. The EIA also indicates that more than 6% of finished gasoline and 5% of diesel fuel (up to 500 ppm sulfur) was imported in the same year. Therefore, more than 70% of the crude oil used to make the transportation fuels consumed in the U.S. is produced outside of the U.S. For this reason, energy consumption and emissions from the production of crude oil outside of the U.S. are of

even more importance than the emissions and energy consumption for domestic crude production.

Other life cycle models of emissions from transportation fuels consider the production of crude oil in a more disaggregated fashion than GREET does. Both the GHGenius Model 3.0 of Natural Resources Canada and the Lifecycle Emissions Model (LEM) on which it is based consider several different types of crude oil production (S&T 2005). The LEM model classifies crude oil as conventional onshore, conventional offshore, and heavy. To be consistent with Canadian statistics, GHGenius 3.0 uses five categories: light (or onshore conventional), offshore conventional, heavy, bitumen, and synthetic, in effect adding to LEM two classifications related to each of the two types of production from oil sands.

Because the model calculations in LEM and GHGenius 3.0 are based on more disaggregated inputs of the energy needed for crude production, the user has more options in selecting the regions and type of crude oil that are expected to be produced when assessing future scenarios. Spreadsheets in the GHGenius 3.0 model allow the user to replace defaults with country-specific data. Whether the results produced through this more disaggregated approach are more accurate than the aggregated approach of GREET will depend on the quality of the energy and emissions data available for the different types and location of crude production as compared to GREET's aggregated inputs.

The GREET assumption that combustion-related GHG emissions (other than from flaring) are the same for domestic and imported crudes is questionable. To the extent that a greater fraction of imported crude is produced offshore or through primary production, the associated emissions could be expected to be less than for domestic crudes, which tend to be produced using more energy-intensive secondary or tertiary production methods. Onshore domestic production often involves significant energy inputs for oil pumping and treating, and therefore offshore production can be much less energy intensive. For example, a large U.S. independent oil producer that we have worked with consumes energy equivalent to just 2.3% of its offshore Gulf of Mexico production while its onshore consumption in the western U.S. (Rocky Mountains) amounts to 8.3% of production. The offshore energy intensity is approximately 26% of the onshore intensity, while the offshore GHG emissions are about 22% of the onshore emissions. Additional research is needed on the energy intensity of conventional petroleum production, both domestically and internationally, to refine the GREET assumptions.

3.3.3 Venting and Flaring from Conventional Oil Production

The other major source of GHGs from crude oil production is emissions of methane from the release of associated gas during production, such as through venting, incomplete combustion in flares, and use of gas-driven pneumatic devices. These emission sources have received increasingly more attention as opportunities for GHG emission reductions than have emissions from energy consumption in oil production.

Statistics on venting and flaring often combine the two processes into a single number. For estimating GHG emissions, it is important to know how much is actually vented and how much

is flared because the quantity of methane released will be much greater if venting occurs. With a global warming potential of methane 21 times greater than for carbon dioxide (based on the second assessment report of the IPCC), small differences in the relative quantities vented and flared can lead to large differences in the total emissions expressed on a carbon dioxide equivalent basis.

The GREET model attributes 20.6% of the total gas flared and vented in the U.S. to venting. This proportion is derived by comparing the emissions estimate for venting with the total amount of gas vented and flared. Since the GREET model was developed, the methodology used by EIA to estimate venting emissions from oil systems has changed, and venting of associated gas at oil wells is no longer captured in the estimate. EPA (2009) reports that venting is now believed to account for less than 20% of the gas vented and flared.

3.3.3.1   Venting

GREET estimates for methane emissions from oil production are based on national-level estimates from the 1997 report *Emissions of Greenhouse Gases in the United States, 1996* (EIA 1997a, Wang 1999). These EIA estimates were calculated using activity data (e.g. thousands of producing petroleum wellheads), augmented with detailed EIA data collection (e.g. EIA-collected firm data on amounts of gas flared or vented) (EIA 1997a, Appendix A, especially Table A-5). These EIA estimates are adjusted by Wang to allocate emissions to produced oil and produced gas based on the ratio of oil and gas energy outputs (Wang 1999, p. 39). The total estimated methane emissions were 0.275 M tonnes, which is equivalent to 20.33 g CH_4/million Btu crude. Because this figure includes CH_4 emissions from combustion, combustion CH_4 emissions in GREET are subtracted from it to arrive at the non-combustion CH_4 emissions.

The EIA's estimation of CH_4 emissions from oil and gas production has evolved over time, and currently, emissions from petroleum production are reported separately from those for natural gas production. The CH_4 emissions in GREET can be compared to values from the current EIA emissions inventory (EIA 2008a). Methane emissions in 2005 from petroleum production were 22.25 M tonne CO_2eq., which is equivalent to 0.810 M tonne CH_4. This figure is almost three times the 1996 value of 0.275 M tonnes, which remains the GREET default. Simultaneously, domestic production of all liquids declined from 8.29 Mbbl/d in 1996 to 6.89 Mbbl/d in 2005 (EIA 2007a, Table 5.1). Thus, methane emissions per unit of production in 2005 were 3.5 times the GREET default. These data suggest a revision in methane emissions per bbl of liquids produced is needed in GREET, as total CO_2 equivalent emissions of crude oil from the well to the refinery increases by about 21% when the updated figures for CH_4 venting are used.

It should be noted that figures published by EPA for CH_4 venting from petroleum systems are even greater. EPA estimates that in 2005, 1.31 M tonnes of CH_4 were vented from petroleum field operations, including 0.071 M tonnes from combustion and process upsets (EPA 2009). Combined with the production decline cited above, this figure suggests a CH_4 venting rate more than 5.5 times that used in the GREET simulations.

EPA conducts its inventory of methane venting emissions from petroleum production using a bottom up approach (EPA 2009). Emission factors are applied to numerous industry activities to

calculate the emissions. The resulting uncertainty in this approach is significant, ranging from -28% to +144% for the 2007 inventory (based on a 95% confidence level using a Monte Carlo simulation). The EIA (2008c) does not provide a similar analysis of the uncertainty of its methane emissions, though it is likely that the range of uncertainty is at least as large. Despite the uncertainties in the EPA and EIA figures for methane venting, they are still significantly above the values used in GREET even at the lower end of the uncertainty range calculated by EPA.

Methane emissions from imported crude oil are less certain due to generally poor data collection practices in many producing countries. IPCC methodologies do not provide nation-specific emissions factors at either the Tier 2 or Tier 3 level (IPCC 2006, Vol. 2, p. 4-64), due to uncertainty and rapid changes in the industry. This uncertainty aside, methane emissions from imported crude oil are likely higher due to lack of gas infrastructure and resulting greater levels of venting and flaring. Wang (1999, p 38) states that the rate of methane venting for imported crude oil in GREET is assumed to be twice that for domestically produced oil, and that 60% of the oil consumed after the year 2000 is imported. This adjustment is applied in the GREET model for methane that is vented with associated gas. Other forms of methane venting are assumed to be the same for both domestic and imported crude oil, amounting to 20.33 g CH_4/million Btu minus emissions from combustion. The GREET documentation does not provide a sound basis for its assumptions regarding the relationship between the venting rates for the production of domestic and imported crude oil.

3.3.3.2 Flaring

The GREET default for the volume of gas flared as part of U.S. petroleum production understates the value reported for the year 2005. The default is based on 159 billion cubic feet of gas flaring for petroleum production, an average for the years 1992 through 1996 (Wang 1999). More recent data for the year 2005 puts this figure at 152 billion cubic feet (EPA 2007). During the same period, however, the amount of domestically produced crude oil has decreased from 6.741 to 5.178 million barrels per day according to EIA (EIA 1997b, EIA 2006b). Thus, instead of the gas flaring rate of 225.8 g/mmBtu (10,500 Btu/mmBtu) assumed by GREET and used in the EPA analysis, a flaring rate of 281.1 g/mmBtu (13,070 Btu/mmBtu) is indicated for 2005.

GREET assumes that twice as much gas is flared per Btu of imported crude oil compared to domestic crude oil. The flared gas per unit of crude oil production in the U.S. is multiplied by 1.6, which results from the assumptions that 60% of U.S. crude oil is imported with the rate of flaring doubled for the imported oil. EIA data indicate that in 2005, the proportion of crude oil that was imported is even greater—66% (EIA 2006b). Thus, GREET likely understates the amount of flaring, although as discussed below, it is not clear by how much.

When looking at the ratio of gas flared to oil produced for crude oil imported into the U.S., it is important to consider the relative quantities of the oil imports as well as the flaring ratio. Table 3.3 lists the flaring ratio (quantity of gas flared per unit of crude oil produced) for domestically produced crude oil and crude oil for the 10 largest sources of imported crude oil. Imports are listed in order of decreasing volume for 2005 (according to EIA data), and the ten countries listed represent more than 75% of the oil imported into the U.S. The quantities of gas flared used

in the calculation of the ratios for 2005 come from an analysis prepared for the World Bank's Global Gas Flaring Reduction partnership in 2007, which used satellite data to assess the amount of flaring by country. Where available, corresponding data are listed from a 2002 World Bank study.

Table 3.3. Estimates of the Ratio of Gas Flared to Oil Produced for Various Locations

Country	Calculated for 2005	World Bank 2002
	Ratio of Gas Flared to Oil Produced (m^3 gas/tonnes oil equivalent)	
U.S.	6.4	22
Canada	8.2	ND
Mexico	4.9	33
Saudi Arabia	5.7	ND
Venezuela	13.6	27
Nigeria	169.5	166
Iraq	78.7	ND
Algeria	61.1	ND
Angola	74.5	118
Russia	117.4	ND
United Kingdom/North Sea	5.6	9
Weighted Average Imports	39.5	NA

Sources: Elvidge et al. 2007, and BP 2009 (for calculating 2005 ratios); World Bank 2002

ND = no data, NA = not applicable

There are some discrepancies between the 2005 and earlier data. The calculated value for the U.S. in 2005 is less than one-third of the earlier value. Canada, the largest source of imported oil in 2005, has a somewhat greater flaring ratio than the U.S. Although Canada was not included in the earlier World Bank report, data in the GHGenius model (S&T 2005) indicates that its flaring ratio is less than that of the U.S. The large difference in the U.S. value and the relative difference compared to Canada may be due to inaccuracies in using satellite data to measure combustion from smaller flares.

If the calculated values for 2005 accurately represent the relative amount of flaring for U.S. and imported crude oil production, the ratio of the weighted average flaring rate to the U.S. rate would indicate how much the U.S. rate should be scaled up to account for imports. The data in Table 3.3 indicates that the flaring rate for imported oil is more than six times that of domestic production, rather than double as assumed in the GREET model. Other data indicate the GREET assumption is more reasonable, however.

EPA's estimate of flaring from domestic crude oil production for 2005 (EPA 2007) combined with EIA data on crude oil production translates into a flaring rate of 281 grams of gas flared/mmBtu. This is 2.9 times the U.S. figure shown for 2005 in Table 3.3. Similarly, the older World Bank figure for the U.S. in Table 3.3 is 3.4 times the figure calculated for 2005. If the flaring rate for the U.S. calculated with EPA and EIA data were substituted for the satellite

estimate of flaring in Table 3.3 and then combined with the 2005 figure of 66% of U.S. crude consumption being imported, the domestic flaring rate would be scaled up by 1.77 to account for the greater flaring of imported crude oil, not 1.6 as is done in GREET, a difference of only about 10%.

3.3.4 Emissions from Oil Sands Production

EPA considered imports of oils sands (tar sands) in setting the 2005 petroleum fuels baseline for the DRIA. EPA's focus was on the quantities imported (primarily from Canada) in relation to other crude oil consumption, which the Agency needed in order to run the GREET model. It is important, however, to also review how the GREET model calculates GHG emissions from the production of oil from tar sands.

A number of LCAs of tar sands production have been performed, although none are comprehensive across all production stages (Suncor 2003; Bergerson and Keith 2006).[12] Fuel cycle emission estimates from several studies are compared in Figure 3.2. One study from the Alberta Chamber of Resources (hereafter ACR), called the *Oil Sands Technology Roadmap* (OSTR), should be noted because it is the source for GREET energy inputs to tar sands production (Larson, et al. 2004). Results from the OSTR study are shown in results 10-11 (row in the figure counting from the bottom) and 15-16 in Figure 3.2.

For comparison, fuel cycle emissions from conventional oil from GREET are about 93 g CO_2e/MJ of refined fuel delivered (the average of gasoline and diesel refining and combustion emissions is used). The GREET results for oil sand mining and in-situ production are 12 and 17 g CO_2e/MJ respectively. Comparing results from GREET to the other LCA estimates made for tar sands production (see dotted lines extending across relevant comparison cases), indicates GREET emissions estimates are generally lower than the corresponding estimates for both in-situ and mining production from other studies.

3.3.4.1   Surface Mining

Surface mining of Alberta tar sands involves removal of overburden, mining the tar sand ore, separating the bitumen from the sand particles, and preparing the separated bitumen for upgrading.

---

[12] It should be emphasized that values of emissions reported by tar sands producers for their operations are typically not based on complete LCAs, as they do not include embodied energy in equipment, transport of the fuel to refineries, etc.
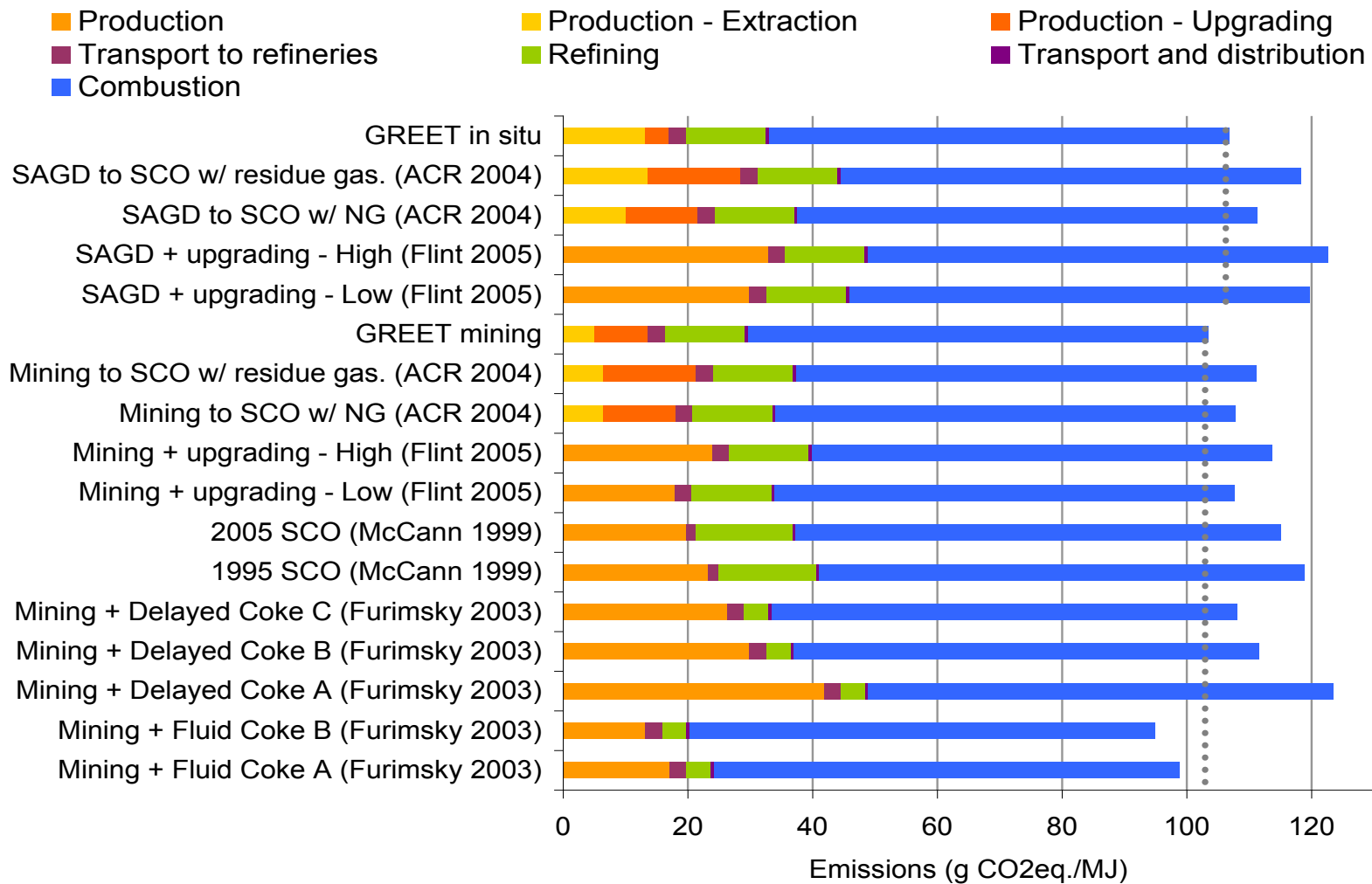
Figure 3.2. Emissions from tar sands production compared to emissions estimated in GREET

Figure 3.2 Detailed Legend:

Results 1-2 are fluid coking of mined bitumen (Furimsky 2003).

Results 3-5 are delayed coking of mined bitumen (Furimsky 2003).

Results 6-7 are 1995 (typical) and 2005 (estimated) emissions from synthetic crude oil (SCO) production (McCann and Magee 1999).

Results 8-9 for bitumen mining plus upgrading to synthetic crude oil (Flint 2005).

Results 10-11 are for mining to premium SCO using natural gas for H_2 source (10) and mining to premium SCO using gasified residues for H_2

Result 12 is GREET estimate for surface mining (Wang 2007).

Results 13-14 for in-situ production source (11) (ACR 2004).using steam assisted gravity drainage (SAGD)+Upgrader (Flint 2005).

Results 15-16 are for SAGD to SCO using natural gas (15), and SAGD to premium SCO using gasified residues (16) (ACR 2004).

Result 17 is GREET estimates for in-situ production (17) (Wang 2007).

Figure 3.2 Construction Notes:

LCA system boundaries and final product mixes differ across these studies, and all attempts were made to make estimates commensurate. For all studies, if a product stage was missing (e.g. transport of crude to refinery was not included), the value from GREET is added. This ensures maximum commensurability between studies, as well as maximum comparability to GREET values. The McCann and Magee analysis (McCann and Magee 1999) is based on undefined "transport fuels" consumed in Central North America. Article text suggests that this is the suite of outputs from refineries, less asphalt, etc., but no firm breakdown is provided. Furimsky (Furimsky 2003) is based on an unspecified final fuel mixture with an assumed specific gravity (sg) of 0.8 and 86 wt% carbon. This is approximately the average sg and carbon weight percent of gasoline and diesel as used in GREET inputs (Wang 1999). Values from ACR are converted from kg CO_2eq./bbl to g CO_2eq./MJ using the heating value of crude oil calculated using the formula from Speight (Speight 2001), assuming sg of SCO output of 0.83 (Furimsky 2003). Values for all GREET parameters, as well as McCann (McCann and Magee 1999) estimates, are calculated assuming average of gasoline and diesel lower heating values (LHV) and GHG emissions.

Overburden removal is typically performed with a truck-and-shovel operation (ACR 2004). Furimsky states that upgrading products, including fuel gas and coke, provide general heat and power for the separation process (Furimsky 2003). On the contrary, GREET appears to assume that natural gas is used in the separation process.[13] In reality, NG would be used only after fuel gas has been used.

Table 3.4 compares GREET fuel shares to an approximate breakdown as calculated from Furimsky (2003) for mining with delayed coking. Note that data are not available from Furimsky for more than an approximate comparison. Furimsky shows significant coke combustion (see ―loss/other‖ row in the table), compared to GREET where coke combustion does not appear to be included (except perhaps implicitly in the electricity category). This missing coke combustion is likely responsible for the discrepancy between GREET emissions estimates and the emissions results from the OSTR. Given that GREET energy inputs are derived from OSTR data, it should be expected that their emissions estimates would be equivalent to OSTR emissions. Figure 3.2 shows that the GREET result for mining-based tar sands emissions, (12, with production and upgrading emissions of 13.6 g CO_2e/MJ) differs significantly from the ACR emissions estimates (10, with production and upgrading emissions of 18.1 g CO_2e/MJ).

This is likely due to the omission of coke combustion in the GREET model, or the assumption of a different primary energy source for tar sands electricity generation than on-site production using coke.[14]

3.3.4.2   In-situ Production

Tar sands can be produced in-situ using three techniques: cold production (only suitable for bitumen above ~12 °API and so not considered further), cyclic steam stimulation (CSS), and steam assisted gravity drainage (SAGD) (ACR 2004). Thermal in-situ production (via CSS or SAGD) is more energy intensive than mining-based production. It also relies more on natural gas inputs than mining operations.

Natural gas consumption for in-situ production is about 1,000 MJ/bbl, while electricity consumption is approximately 30 MJ/bbl (8.25 kWh) (ACR 2004). These values are used by GREET, and no other breakdown of energy inputs to in-situ production was found with which to compare these values. GREET assumes that current in-situ production is not upgraded, although other estimates presented above in Figure 3.2 do assume that it is upgraded.

---

[13] It is unclear from the GREET documentation whether ―natural gas‖ is purchased natural gas or fuel gas produced in coking. Furimsky implies that all central energy inputs except H_2 production for secondary upgrading are from co-produced fuel gas and coke from primary upgrading. See figures and notes in the tables in the paper for additional discussion.

[14] One possible explanation for the discrepancy is that the GREET energy inputs might have been derived from Figure 7.2 in the ACR report, which is titled ―Energy elements in the cost chain.‖ This figure includes natural gas and electricity, which are purchased inputs. Because coke is a byproduct fuel, it does not show up in this cost figure, but would show up in energy balances and carbon emissions.

Table 3.4. Emissions from Surface Mining-based Tar Sands Production

Process Input	GREET 1.8[a]		Furimsky 2003[b]	
	% energy to bitumen extraction	% energy to bitumen upgrading[a]	% energy input to bitumen extraction	% energy input to bitumen upgrading
Crude oil	0	0	0	0
Residual oil	0	0	0	0
Diesel	0.6	0	2.1	0
Gasoline	0	0	0	0
Natural gas	82.3	97.1	42.1[c]	~100
Electric	17.1	2.8	Uncertain[d]	0
Loss/other [d]	0.1	0.1[e]	55.8[f]	0
Total	**100**	**100**	**100**	**100**

a – Data from GREET version 1.8 (Wang 2007). Documented in GREET 1.5 documentation, Tables 4.3 and 4.4 (Wang 1999).

b – Data for Furimsky's delayed coking case A (result 3 from Figure 3.2 above). This case was chosen because its results differ most significally when compared to the GREET estimates. This case is not the most coke-dependent. Furimsky's Case B is, which he also considers the most realistic. Furimsky's results values are converted to heating values using fuel gas and coke heating values (Furimsky 1998; EIA 2007a).

c – This is fuel gas produced during coking and consumed in fueling bitumen extraction (for electricity generation and heat generation). Furimsky does not specify quantities used to generate electricity. (Furimsky states that natural gas is only used in upgrading for H_2 generation, while the rest of the process is fueled by coke and coking fuel gas.)

d – Some portion of ―natural gas‖ and ―other‖ is used to generate electricity.

e –These energy inputs include ―refinery still gas‖ which could be fuel gas produced from coking process.

f – This is coke combusted to provide process heat and electricity in on-site generation facilities (Furimsky 2003).

3.4   Petroleum Refining

The GREET model defines an efficiency metric for petroleum refining to calculate life cycle GHG emissions, as it does for other process steps. As described recently by Wang (2008), the refinery efficiency is defined as:

$$OverallEfficiency = \frac{EnergyOutput}{EnergyInputs}$$

where:

Overall Efficiency = petroleum refinery energy efficiency

Energy Output = energy in all petroleum products of the refinery

Energy Inputs = energy in crude oil input, other feedstock inputs, and process fuels (including purchased electricity and steam)

The refinery efficiency is key parameter in GREET because the efficiency and GHG emissions of all the refinery products depend on it. The efficiency has not, until recently, received much attention as the GREET model has evolved. An efficiency figure of 0.88 had previously been used (Wang 2008) and, aside from adjustments for hydrogen use, was little changed since Version 1.6 of GREET (2001).

The figure of 0.88 for the refinery efficiency came from ANL's analysis of three separate linear programming studies conducted for the California Energy Commission, the Engine Manufacturers Association, and the Alliance of Automotive Manufacturers (Wang 2008). Based on comments from ExxonMobil, Argonne conducted a review of the refinery efficiency used in GREET, resulting in a revised figure for Version 1.8b.

Instead of using the efficiency derived from the linear programming studies, the figure in GREET is now based on EIA data furnished by refineries on their inputs and production. In order to use these data to calculate the refinery efficiency, Argonne had to make two adjustments. The volume or mass units in which the data were reported, had to be converted to energy units, and natural gas consumption used for the production of hydrogen had to be added to the inputs. Each of these adjustments adds some uncertainty to the efficiency figure used in GREET.

Crude oil is by far the largest input to a refinery, and therefore it is important that the units reported to EIA—barrels—be correctly converted to energy units. EIA tracks and annually reports the actual energy content of imported crude oil. Argonne used the weighted average figure (for 2005) in its calculation of crude oil energy inputs. For domestically produced crude oil, however, a default value of 5.8 million Btus per bbl on a higher eating value (HHV) basis has been used to convert from barrels of crude oil into energy units. While the oil industry is required to use this conversion factor, which comes from a 1950s publication, for various kinds of government reporting, it does not necessarily represent the actual energy content of current domestically produced crude oil. There is reason to believe that it underestimates the actual energy content.

Other sources of information suggest that crude oil has an energy content greater than 5.8 million Btus/bbl (all expressed on an HHV basis). Imported crude oil was reported by the EIA to have an energy content of 5.98 million Btu/bbl in 2006, and while it varies somewhat from year to year, has never been less than 5.9 million Btus/bbl during the last 20 years (EIA 2008b). Shires and Loughran (2004) report crude oil heat contents of 5.55 to 6.40 million Btu/bbl, suggesting that 5.8 million Btu/bbl is on the low side. Typically a conversion of 6 million Btu/bbl is used when converting natural gas to barrels of oil equivalent. In the information ExxonMobil provided to Argonne, a figure of 6.025 million Btu/bbl was used.

The effect of changing the heat content of the domestically produced crude oil are significant. Argonne's revised efficiency of 90.1% drops to 89.1% merely by changing the domestic crude oil heat content from 5.8 to 6.0 million Btu/bbl.

The revised GREET refinery efficiency also appears to underestimate the amount of natural gas (and thus energy) required to make the hydrogen consumed at refineries. Because the EIA data does not readily allow hydrogen consumption to be determined, Argonne relied on information from the Chemical Economics Handbook on the quantity of hydrogen consumed by refineries. It then converted this figure into a quantity of natural gas consumed to allow the overall refinery efficiency to be calculated. Using an efficiency of hydrogen production of 71% (based on lower heating values), Argonne reported a refinery consumption to produce the equivalent of 1.693 million MMSCF of hydrogen would require 701 thousand MMSCF of natural gas. The data of Boyce, et al. (2004) suggest a somewhat greater figure. Their report suggests natural gas consumption of between 763 and 818 thousand MMSCF of natural gas, depending on the age of the plants producing the hydrogen.

The effect of greater natural gas consumption for hydrogen production has a less pronounced effect on the efficiency figure than the suggested correction of the crude oil heat content. In the case of 818 thousand MMSCF of natural gas consumed, which would be the worst case scenario if all hydrogen plants were of an older steam methane reformer design, the refinery efficiency drops from 90.1 to 89.8% as compared to the drop from 90.1 to 89.1% when the heat content of domestic crude is set at 6 million Btu/bbl. (The same 0.3% drop occurs—from 89.1 to 88.8%—if the lower quantity of natural gas consumption is assumed at 6 million Btu per bbl for domestic crude oil.)

In addition to the overall refinery efficiency, which indicates the amount of energy needed to produce a slate of products, the amount of energy needed to produce specific motor fuels is needed to assess the fuel cycle energy consumption and emissions of each fuel. GREET 1.8 continues to rely on the same rule of thumb allocation that earlier versions of the model have used: 60% of the crude oil refined is for gasoline production, 25% for diesel production, and the remaining 15% for other petroleum products (Wang 2008). The basis for this allocation is not well justified. This results in a somewhat different distribution of refinery energy among the products—and thus greater emissions allocated to some products, such as diesel fuel—compared to other studies and models by GHGenius, the National Energy Technology Laboratory (NETL), the Alberta Energy Research Institute (AERI), and the Joint Research Centre (JRC) (O'Conner 2005, NETL 2008, Keesom and Unnasch 2009, Rosenfeld et al. 2009, and Edwards et al. 2008). As shown in Table 3.5, while GREET is shows consistently greater energy consumption for each type of motor fuel when compared to the GHGenius model, the difference is most pronounced for Low Sulfur Diesel fuel, and least pronounced for reformulated gasoline.

Table 3.5. Refinery Energy Consumption in GREET1.8 and GHGenius

Refinery Energy (Btu/mmBtu fuel)	Conventional Gasoline	Reformulated Gasoline Feedstock	Low Sulfur Diesel Fuel
GREET 1.8c.0	140,251	146,789	119,821
GHGenius	121,000	142,000	94,000
Difference, %	**15.9**	**3.4**	**27.5**

Source: GREET 1.8c.0, S&T (2005)

Refinery emissions also depend on the distribution of fuels consumed within the refinery to produce the finished product. Table 3.6 compares the distribution of fuels in GREET 1.8c.0 to other studies. In general, the assumptions in GREET are consistent with the other studies, particularly for the largest energy source, refinery still gas. GREET tends to ascribe more of the energy to natural gas and less to coke, but the difference is not expected to significantly affect the refinery GHG emissions per unit of fuel produced.

Table 3.6. Share of Energy Input to Refineries in GREET and Other Studies

Share of Energy Input	GREET 1.8c.0 Default	GHGenius, S&T 2005	Wang 2008	NETL 2008
Residual Oil	3.0	0.5	0.4	0.5
Natural Gas	30.0	23.6	23.2	23.9
Still Gas	50.0	48.9	48.4	48.7
Coal (Coke)	13.0	18.4	17.7	18.4
Electricity	4.0	4.3	4.3	4.3
Purchased Steam	0.0	2.6	4.3	2.6
LPG	0.0	0.6	0.3	0.5
Other	0.0	1.2	1.3	1.2

3.5   Recommendations

3.5.1   Recommendations For Improving EPA's Use of the GREET Model

EPA needs to revisit adjustments for the imports of heavy oil and Venezuela extra heavy crude oil. The single source EPA cites for making this adjustment contains no back-up data to support its emissions values. If such an adjustment is to be made, EPA should provide a rigorous justification for it. EPA also needs to explain how the correction factors it applies to crude oil interact with the correction factors GREET already applies to all types of imported crude oil.

EPA should re-run the GREET model using the correct proportion of gasolines and diesel fuels sold in 2005. Instead of using data on ―Refiner Sales to End Users," for gasoline, it should use ―Prime Supplier Sales" to represent the mix of different types of gasoline sold each year.

EPA should also re-run the GREET model for diesel fuel, selecting ―conventional diesel" in GREET rather than ―low sulfur" diesel fuel. This will correct the mistake EPA made in modeling diesel fuel production in GREET as if it were ultra-low diesel (as defined by the EIA) when in fact virtually no ultra low sulfur diesel fuel was sold in 2005.

3.5.2   Recommendations for Improving the GREET Model Itself

The energy and emissions data for petroleum production in GREET should be improved with updated data for domestic and imported crude oil. Because approximately 70% of gasoline and diesel fuel originates from foreign crude oils, the model should not use domestically produced

crude oil as the basis for its emissions estimates for foreign crude oil through the use of ad-hoc assumptions about the relationship between the two. Instead it should use real data from more up to date studies on the emissions associated with the production of foreign crudes, particularly as emissions associated with flaring and venting.

The estimation of emissions from petroleum refining also need to be improved in GREET with an updated review of the literature including recent reports by the Alberta Energy Research Institute (AERI 2009) and the National Engineering Technology Laboratory (NETL 2008). In particular:

- The overall refinery efficiency should be reexamined using better information on the heat content of domestic crude oil. Actual data on the heat content of domestically produced crude oil should be used instead of a default value.
- Natural gas consumption and emissions associated with the production of hydrogen should also be reexamined as it appears to be underestimated.
- The GREET model should be revised to use a more rigorous approach to allocating refinery energy and emissions among the refined products. Instead of using a ―rule-of-thumb‖, the allocation should be based on the actual energy and emissions associated with the unit operations needed to make the products.

Implementation of these recommendations will improve the accuracy of the 2005 baseline EPA was charged with developing under EISA.

3.6   References

ACR (2004). Oil Sands Technology Roadmap: Unlocking the Potential. Alberta Chamber of Resources**:** 92.

AERI (2009). Life Cycle Assessment Comparison of North American and Imported Crudes. Prepared for the Alberta Energy Research Institute by Jacobs Engineering and Life Cycle Associates, July 2009.

Aycaguer, A. C., M. Lev-On, et al. (2001). Reducing Carbon Dioxide Emissions with Enhanced Oil Recovery Projects: A Life Cycle Assessment Approach." Energy & Fuels 15(2): 303-308.

Bergerson, J. and D. W. Keith (2006). Life Cycle Assessment of Oil Sands Technologies. Alberta Energy Futures Project. Environment and Economy**:** 28.

Boyce, C.A., et al. (2004). "Time for a New Hydrogen Plant?" Hydrocarbon Engineering, February 2004.

BP (2009). BP Statistical Review of World Energy, June 2009.

CAPP (2007). Crude Oil Forecast, Markets and Pipeline Expansions. Canadian Association of Petroleum Producers. June 2007.

Cleveland, C. J. (1991). Physical and Economic-Aspects of Resource Quality - the Cost of Oil-Supply in the Lower 48 United-States, 1936-1988. Resources and Energy 13(2): 163-188.

Cleveland, C. J. (1992a). Energy Quality and Energy Surplus in the Extraction of Fossil Fuels in the U.S." Ecological Economics 1992(6): 139-162.

Cleveland, C. J. (1992b). Yield Per Effort for Additions to Crude-Oil Reserves in the Lower 48 United-States, 1946-1989." AAPG Bulletin, American Association of Petroleum Geologists 76(6): 948-958.

Delucchi, M. A. (1991). Emissions of Greenhouse Gases from the Use of Transportation Fuels and Electricity - Volume 1: Summary. Argonne National Laboratory**:** 153.

Edwards, R., et al. (2008). Well-to-wheels Analysis of Future Automotive Fuels and Powertrains in the European Context: Well-to-Tank Report, Version 3. EUCAR, CONCAWE, and JRC/IES.

EIA (2008a). Emissions of Greenhouse Gases in the United States 2007. Energy Information Administration.

EIA (2008b). Annual Energy Outlook: 2008. Monthly Energy Review, Appendix A. Energy Information Administration, May 2008.

EIA (2007a). Annual Energy Review 2006. Annual Energy Review. Energy Information Administration.

EIA (2007b). Emissions of Greenhouse Gases in the United States 2006. Energy Information Administration.

EIA (2006a). Petroleum Supply Annual 2005, Volume 1. Energy Information Administration, Washington, DC.

EIA (2006b). Annual Energy Review 2005. Energy Information Administration, July, 2006.

EIA (2006c) Petroleum Marketing Annual 2005. Energy Information Administration, August, 2006.

EIA (1997a). Emissions of Greenhouse Gases in the United States 1996. Energy Information Administration.

EIA (1997b). Petroleum Supply Annual 1996. Energy Information Administration.

Elvidge, C.D, et al., (2007). A Twelve Year Record of National and Global Gas Flaring Volumes Estimated Using Satellite Data. Final Report to the World Bank. NOAA National Geophysical Data Center.

EPA (2009). Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2007. U.S. Environmental Protection Agency. April, 2009 (Section 3.6).

EPA (2008). EPA Fuel Life Cycle GHG Estimates Update, Staff Distribution Draft, U.S. Environmental Protection Agency. February 5, 2008.

EPA (2007). Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2005. U.S. Environmental Protection Agency. April, 2007 (Table A-125).

Ethanol Producer Magazine (2009) Ethanol Plant List, www.EthanolProducer.com. Updated October 15, 2009.

Flint, L. (2005). Bitumen Recovery Technology: A Review of Long-term R&D Opportunities, Lenef Consulting Limited: 210.

Furimsky, E. (2003). Emissions of Carbon Dioxide from Tar Sands Plants in Canada. Energy and Fuels 17: 1541-1548.

Furimsky, E. (1998). Gasification of Oil Sand Coke: Review." Fuel Processing Technology 56(3): 263-290.

IPCC (2006). IPCC Guidelines for National Greenhouse Gas Inventories. S. Eggleston, L. Buendia, K. Miwa, T. Ngara, and K. Tanabe, National Greenhouse Gas Inventories Programme, Intergovernmental Panel on Climate Change.

Keesom, W., and S. Unnasch (2009). Life Cycle Assessment Comparison of North American and Imported Crudes. Prepared for the Alberta Energy Research Institute by Jacobs Engineering and Life Cycle Associates July 2009.

Larson, R., et al. (2004). Might Canadian Oil Sands Promote Hydrogen Production Technologies for Transportation. Argonne National Laboratory.

Loreti, C. and M. Murphy (2005). Review of the Well-to-Pump Pathways for Petroleum Fuels and Alternative Fuels in the GREET Model. Report to the American Petroleum Institute, December, 2005.

McCann, T. and P. Magee (1999). Crude Oil Greenhouse Gas Life Cycle Analysis Helps Assign Values for CO_2 Emissions Trading. Oil & Gas Journal 97(8).

NETL (2008). Development of Baseline Data and Analysis of Life Cycle Greenhouse Gas Emissions of Petroleum-Based Fuels. National Energy Technology Laboratory, DOE/NETL-2009/1346, November 26, 2008.

O'Conner, D. (2005). Documentation for Natural Resources Canada's GHGenius Model 3.0, prepared for Natural Resources Canada, by (S&T)[2] Consultants.

Proctor, C. (2005). Suncor Buys Second Denver Refinery. Denver Business Journal. Denver, CO.

Rosenfeld, J., et al. (2009). Comparison of North American and Imported Crude Oil Lifecycle GHG Emissions. Prepared for the Alberta Energy Research Institute by TIAX, LLC.

S&T (2005). Documentation for Natural Resources Canada's GHGenius Model 3.0, prepared for Natural Resources Canada, by (S&T)[2] Consultants, September, 2005.

Shires, T. M. and C. J. Loughran (2004). Compendium of Greenhouse Gas Emissions Methodologies for the Oil and Gas Industry. American Petroleum Institute.

Speight, J. G. (2001). Handbook of Petroleum Analysis. New York, Wiley-Interscience.

Suncor (2003). Suncor Energy Inc. 9th Annual Progress Report. Suncor Energy Inc.: 36.

USADC (2004). Economic Census - Crude Petroleum and Natural Gas Extraction: 2002. U.S. Department of Commerce, U.S. Census Bureau.

Wang, M. (2008). Estimation of Energy Efficiencies for U.S. Petroleum Refineries. Center for Transportation Studies, Argonne National Laboratory, March 2008.

Wang, M. Q. (2007). GREET Model 1.8a. Argonne National Laboratory.

Wang, M. Q. (1999). GREET 1.5 - Transportation Fuel-Cycle Model - Volume 1: Methodology, Development, Use, and Results. Argonne National Laboratory.

World Bank (2002). Global Gas Flaring Reduction Initiative; Report on Consultation with Stakeholders. (Report of Oslo, Norway, Conference April 15-16, 2002.). World Bank.

Appendices

A   EPA LCA Modeling Approach

EPA combines a U.S. market analysis in FASOM with an international analysis in FAPRI and combines the results with a process energy analysis from GREET. One advantage of the process analysis approach in GREET is consistency in the life cycle inventory for different energy carriers and input assumptions. Using three different models to assess GHG impacts provides significant opportunities for applying inconsistent modeling assumptions.

EPA has reviewed methodologies for advancement in the analysis of the life cycle GHG emissions from biofuels. Their approach often combines of economic modeling and GHG accounting without distinguishing between direct and/or indirect effects of biofuel development. While this approach clearly represents a methodological advance, it also reveals the challenges of accurately estimating the GHG effects of biofuels. Uncertainty is an unavoidable factor in this type of analysis. Unfortunately, EPA has not adequately characterized the uncertainties in its estimates. However, EPA is not unlike other environmental agencies in other countries where they are faced with the questions raised during the review process. The difficulty is how to distinguish what metrics can be adequately measured, and to what extent; and likewise what aspects of GHG emissions cannot be quantified.

Land Use Change metrics and GHG emissions models under EPA consideration include Domestic and International models and data sources. They include:

- Direct Emission factors – GREET, data in FASOM
- Land carbon data analysis - Winrock, Woods Hole
- Agricultural sector models (FASOM, FAPRI, GTAP)
- Fertilizer N2O modeling (CSU DAYCENT/CENTURY)
- Fuel production process models (USDA & NREL ASPEN models)
- Tailpipe emissions (MOVES)
- Energy sector modeling (NEMS)

The following sections detail the majority of these models and describe how EPA proposes use of each in the next RFS-2.

A.1 Domestic Agricultural Sector Model

The comprehensive agricultural sector model FASOM is used by EPA to determine U.S. domestic sector-wide impacts of increased biofuel production. Attributes of FASOM include:

- Accounts for changes in CO_2, CH_4, and N_2O from agricultural activities.
- Tracks carbon sequestration and carbon losses over time.
- Tracks five forest product categories and over 2,000 production possibilities for field crops, livestock, and biofuels.

This model is currently not publically available and so an informed opinion of this model cannot be provided without further understanding of its application and use.

A.2 International Agricultural Sector Model

Comprehensive models for worldwide agricultural sector include FAPRI for a reference case and policy case to determine changes in U.S. exports due to increased domestic biofuel production and international increased corn production, decreases in other crops, and changes in total crop acres. USDA's Office of Chief Economist, Congress, and the World Bank have utilized the FAPRI modeling structure to examine agricultural impacts from World Trade Organization proposals, changes in the European Union's Common Agricultural Policy, and the impact of biofuel development in the United States. This model is also not publically available.

GHG emissions used FASOM and FAPRI results. Ethanol process emissions were based on process models from USDA. Feedstock and ethanol transportation were based on GREET. This combined approach was applied to various fuels and feedstocks.

A.3 GREET

The GREET model life cycle components include process inputs for feedstock production, transport, ethanol plant operation, fuel delivery and vehicle operation. These steps include the well-to-tank (WTT) and tank-to-wheel (TTW) components that are calculated in the GREET model. The WTT phase includes the upstream or fuel cycle emissions. The TTW phase includes the emissions from the vehicle including fuel carbon converted to CO_2 as well as N_2O and CH_4 emissions generated by the combustion process.

GHG emissions are summed using the same energy accounting system used in the GREET model. The specific energy or material consumption (S) provides the consumption rate for the life cycle inventory. The life cycle emissions (E) for each life cycle inventory component step (i) are based on values from the GREET model. Inputs upstream of the ethanol plant include a loss factor (L). Thus the upstream and vehicle emissions (EU) over the total fuel cycle are represented by:

$$EU = \Sigma \, (S \times E \times L)i$$

With this accounting approach, WTT and TTW emissions are treated comparably and report in g/MJ or g/mi.

A.4 GTAP

The RIA example of GTAP modeling measures grassland and savanna, using the Brazil case. There are no specific results stated. EPA states that they are ─looking further into GTAP' by mentioning GTAP's work in cellulosic ethanol.

Based on modeling interactions of land types as opposed to use of historic trends, GTAP provides: acres by country, different total acreage conversion amounts, and different types of land conversion.

However, GTAP has several issues as follows:

- It is a static model based on a fixed year (such as the 2001 economy) and does not take into account economic and agricultural commodity trends beyond 2022. This is important because the DRIA looks at indirect effects for 30 year and 100 year time horizons.
- GTAP does not currently contain unmanaged land, which is a significant potential source of GHG emissions.
- GTAP does not provide the same level of detail as it does for commodities markets (e.g. does not individually represent palm as a feedstock but rather as an ‗oilseed‘ and really oilseeds could be one of many feedstocks).
- Current uses of GTAP to determine iLUC for biofuels do not provide a clear documentation of the biorefinery performance characteristics including yield, capital cost, power consumption, and co-products used to develop the economic sectors developed in GTAP.

A.5 MODIS and Satellite Software for Land Use measurement of Crop Expansion.

Two tools are used by the MODIS land team to assess data quality; confusion matrixes and aggregations of confidence values. The confusion matrixes describe how well the training sites are classified when they are unknown by the classifier, and so provide information on the accuracy of the classification process as applied to the training site database. The confidence values are generated by the classifier and indicate how well the pattern of spectral and temporal variation in annual observations of each pixel fits the examples of training data provided to the classifier. They may be treated as probabilities of correct classification, given the input training data.

Comparison of MODIS 17 classification system of land types to the FRA 2005 (FAO) dataset. reveals several differences that were noted by EPA.

Classification of MODIS data by Winrock classifies grassland and savannah as pastureland. If this conversion is calculated then land use change goes up significantly when IGPG data is used, so they added ‗pasture replacement‘ to land use change overall calculation.

A.6 Model Treatment of System Boundary Life Cycle Inputs Parameters

The life cycle system boundary for a fuel production is the first critical choice for an LCA analysis. This boundary should be as tightly drawn as possible to detail the production process-from the well-to-wheel (WTW). For a biofuel such as corn ethanol, for example, this includes farming operations such as feedstock planting, harvesting, transportation fuel processing,

delivery, and vehicle end use. The inputs to the process vary according to the production technology, of course, but this can and should be adequately assessed within the LCA.

The Life Cycle Boundary under the DRIA was determined based on internationally accepted life cycle assessment standards and developed by the International Organization for Standardization (ISO), using environmental significance as the cut-off criteria. The boundary excluded the following components:

- Infrastructure-related activities (e.g., emissions associated with the production of tractors or farm equipment)Construction-related emissions (e.g., steel or concrete needed to construct a refinery)
- The RIA issues with the system boundary are also discussed in Section 2.25 with a focus on the tightening of the system boundary and how this may have been approached differently by EPA.

Life Cycle Analysis results can vary widely depending on the assumptions made for the analysis. The system boundary is critical to determining fuel production processes and the resulting production of by-products, which can then be sold on the open market. For example, gypsum is a by-product of waste-to-ethanol production and thus has economic value and is suitable for receiving a by-product credit. Life Cycle analyses either calculate these by-products as co-products by using the substitution, distribution or allocation method. The GREET model for allocation is based on the substitution method with the life cycle inventory of gypsum based on the energy inputs and emissions for surface mining minerals. The credit is a relatively small fraction of the life cycle analysis and is included for completeness.

Another example is that of corn. GREET employs the substitution/displacement method for corn ethanol. Dry Distillers Grains and Solubles (DDGS) is a co-product of dry mill ethanol production. DDGS can be used as cattle feed-DDGS is substituted for corn and soybean meal. Dry Mill Corn Ethanol is given energy and emission credits equal to the energy and emissions associated with corn and soybean meal production and transportation. EPA adopted this methodology in its Renewable Fuel Standard modeling, but adjusted the values somewhat. GREET employs an allocation methodology based on energy intensity for soybean based biodiesel production.

Co-Product Credits include production of alternative fuels yields by counting useful co-products. Since it is not appropriate to assign all of the production energy and emissions to the fuel, a methodology is needed to fairly split the energy and emissions between the product fuel and the co-products. As discussed, the substitution or displacement method substitutes co-products for other substances. A credit is determined based on the energy/emissions associated with the other substances. Other methods include the displacement method.

B   Conformance with International Standards for Life Cycle Assessment

The International Standards Organization (ISO) has published two standards related to Life Cycle Assessment (LCA). These are ISO 14040: Environmental Management—Life Cycle Assessment—Principles and Framework [A], and ISO 14044: Environmental Management—Life Cycle Assessment—Requirements and Guidelines[B]. As the titles suggest, ISO 14040 covers more general aspects of environmental LCAs and ISO 14044 more specific requirements and guidelines for conducting them.

EPA's RIA for the RFS program does not claim to be an LCA as defined by the ISO standards. Nevertheless, it does contain a chapter called ―Lifecycle Impacts on Fossil Energy and Greenhouse Gases." This discussion briefly describes the ISO LCA standards and considers how the analysis in that chapter conforms to those standards.

B.1 The ISO 14040 and 14044 Standards

The ISO standards identify four phases of an LCA study:

- •   Goal and scope definition,
- •   Inventory analysis,
- •   Impact assessment, and
- •   Interpretation.

ISO 14044 requires that the goal of the study state the intended application and reasons for carrying out the study, as well as the intended audience and whether the results will be used in comparative assertions intended to be disclosed to the public.

The scope of the study, according to ISO, shall describe the product systems to be studied, and the functions of the systems. The functional unit (the quantified performance of a system used as the basis of comparison), boundaries of the system, allocation procedures, impact assessment methodology and types of impacts, data requirements, assumptions, value choices, limitations, data quality requirements, type of critical review, and type and format of the report are also to be described in the scope of the LCA.

Life Cycle Inventory (LCI) Analysis, the second step in an ISO LCA, entails the collection of quantitative and qualitative data for each unit process within the system boundary. These data may include energy, raw material, and ancillary inputs, products, co-products and waste, releases to air, water, and soil, and other environmental aspects. In this step, the validity of the data is checked, the data are related to the functional unit, the system boundary is refined as necessary, and the allocation of inputs and outputs to different products is made and documented.

Lifecycle Impact Assessment (LCIA) characterizes the environmental impacts of the data compiled in the LCI. It is a relative approach to characterizing environmental performance as it

is based on the functional unit for the system. The LCIA consists of several mandatory elements: selection of impact categories, category indicators, and characterization models, assignment of the LCI results to the selected impact categories, and calculation of category indicator results.

The final step in an ISO LCA is Life Cycle Interpretation. This step consists of three elements: the identification of the significant issues based on the results of the LCI and LCIA; an evaluation that considers completeness, sensitivity, and consistency; and the presentation of conclusions, limitations, and recommendations.

The LCA report itself will be written in the format defined in the scope phase of the study. The ISO 14044 lays out in detail the specifics that are to be included in the report, as well as the additional requirement for reports that contain comparative assertions about product systems and are disclosed to the public. One of these additional requirements is a description of the critical review process, which is required in such cases, the results of the review, and responses to the recommendations.

B.2 EPA's Renewable Fuel Standard and ISO LCA Standards

B.2.1. Goal and Scope Definition in the RIA

As noted above, EPA's analysis of the RFS is a regulatory impact analysis, rather than a Life Cycle Assessment. Although Chapter 6 of the RIA is entitled ―Lifecycle Impacts on Fossil Energy and Greenhouse Gases," the discussion in this chapter does not consider the full suite of environmental impacts typically considered in an LCA, such as releases to water and soil or releases to air, other than of greenhouse gases. For this reason, as well as those described below, the analysis in EPA's RIA should be considered to be an abbreviated LCA conducted mostly outside of the ISO framework.

The RIA states that the goal of the lifecycle analysis is to ―….determine the GHG emissions and fossil fuel impact of the increased use of renewable fuels." Rather than comparing two product systems that produce the same functional unit (e.g., combustion of one million Btus of transportation fuel), the EPA analysis compares future scenarios for increased use of renewable fuels with a reference case of renewable fuel use at current levels. The goals statement does not define what these current levels and future scenarios are, however.

The goal description in the RIA does not state who the intended audience of the lifecycle assessment is or whether the results will be used in comparative assertions that are made public. Presumably, the audience is the general public, as well as policy makers, and comparative assertions are implicit in the goal of the work. These two pieces of information are important because they lead to the additional requirements for comparative LCAs that are made public.

The RIA describes the product systems to be studied as conventional and alternative fuels from well to wheels—that is from the acquisition of raw materials through the use of the fuels in motor vehicles. It does not clearly define a functional unit, however, on which to compare the

fuels on a common basis. Such a metric might be a given high heating value of fuel combusted, or a given distance traveled in a particular type of vehicle. Instead, the system appears to be the well to pump emissions of GHGs per unit of fuel, with the assumption that the amount of fuel and the non-CO2 GHG emissions during use are the same for conventional and renewable fuels, and that the same fraction of carbon is oxidized to CO2 during the use of the fuels.

The RIA describes the system boundary and notes that emissions associated with international land use changes are not included within the scope of the LCA due to limitations in modeling capabilities. While it notes this as a shortcoming, it does not (and cannot) quantify the effects on the results.

The RIA does not describe any cut-off criteria for the inclusion of inputs and outputs. The ISO standard requires that this cutoff be clearly described. When assessing the upstream GHG emissions associated with the production of a fuel, for example, this would mean setting some criterion for inclusion of GHG emissions in the lifecycle accounting and consistently applying this criterion.

Another key omission in the RIA is a discussion of the critical review for the study. Under ISO 14044, a critical review is a requirement for this sort of public analysis of product options, yet it is not discussed in this chapter.

B.2.2. Life Cycle Inventory in the RIA

The LCI in the RIA is conducted through the use of the GREET model to assess fuel cycle GHG emissions and energy consumption, and land use models to assess changes in GHG emissions from changes in domestic land use. A description of data quality requirements, including sources of data, is another requirement of ISO 14044. While the RIA provides this kind of information in the context of using the GREET model to conduct its analysis, it does not discuss the much larger set of data embodied in GREET itself, and a complete, and up-to-date description for the current version of the GREET model and associated data references does not exist. Thus validation of the modeling data is extremely difficult.

Allocation procedures do not appear to be handled consistently in the RIA. The procedures are described in the RIA as they relate to dried distillers grains with solubles, which are co-produced with ethanol, as required by ISO 14044. For, soybean meal, a coproduct, of biodiesel production, however, no such discussion is presented, and it is unclear how, or if any allocation is performed.

B.2.3. Life Cycle Impact Assessment in the RIA

The RIA does not include a Life Cycle Impact Assessment as described in the ISO 14044 standard. The only impacts that are considered are for energy use and GHG emissions, and for these it does describe how the impacts are characterized. For example, the 100-year global warming potentials published by the Intergovernmental Panel on Climate Change serve as the characterization model for the carbon dioxide, methane, and nitrous oxide emissions.

The ISO 14044 standard takes a much broader view of environmental impacts than the RIA does, looking beyond energy and GHG emissions. Land use is mentioned specifically as one type of result (other than mass and energy flows) that may be part of an LCI and therefore would have to be identified and considered as part of the impact assessment. The RIA does this only in the context of CO_2 emissions from domestic land use changes. It does not address other environmental impacts associated with domestic land use changes or any impacts associated with international land use changes.

B.2.4. LCA Interpretation in the RIA

The RIA does not contain a section that specifically addresses Life Cycle Interpretation, which is one of the required elements under ISO 14044. Some of the elements required by the ISO standard are included in the broader discussion of the RIA's Lifecycle Impacts chapter, but others are not. In particular, there is relatively little discussion of the completeness, sensitivity, and consistency checks of the analysis.

The ISO standard requires that conclusions be drawn from the study. Conclusions are presented in the RIA on changes in energy use and GHG emissions. They are not, however, presented in the context of the checks listed above and the requirements of the goal and scope of the study. The ISO standard also requires that information on the critical review be included in the LCA report. Since such a review was not conducted for the RIA, none was included in the report.

B.3 ISO References

ISO 14040: Environmental Management—Life Cycle Assessment—Principles and Framework. International Standards Organization, Geneva, 2006.
ISO 14044: Environmental Management—Life Cycle Assessment—Requirements and Guidelines. International Standards Organization, Geneva 2006.

C Review of NAS Study, EPA Modeling Guidance, and Regulatory Impact Assessment

EPA has relied on a set of software models for its analysis of the greenhouse gas (GHG) impacts of fuel production and use in its analysis for the RFS. These include Argonne National Labs' GREET model for fuel cycle analysis, as well as two partial equilibrium models (FAPRI and FASOM-GHG) for the estimation land use conversions induced by the expansion of biofuels production.

C.1 Objectives

This section examines EPA's draft RIA in the context of guidelines it has established for modeling in support of environmental policy. We reviewed EPA and other modeling recommendations and examined how these were applied in analyses performed in support of the RFS2 rulemaking proposal

C.1.1. EPA Environmental Analysis Guidelines

The following documents were evaluated as part of this assessment:

- EPA, (2009),Draft Regulatory Impact Analysis: Renewable Fuel Standard Program. May 2009, Assessment and Standards Division, Office of Transportation and Air Quality, U.S. Environmental Protection Agency: Washington, DC. (Referred to hereafter as ―RIA".)

- EPA Science Advisory Board, (2006), Review of Agency Draft Guidance on the Development, Evaluation, and Application of Regulatory Environmental Models and Models Knowledge Base, US Environmental Protection Agency. (Referred to hereafter as ―SAB".)

- NRC, (2007), Models in Environmental Regulatory Decision Making, Committee on Models in the Regulatory Decision Process of the National Research Council. (Referred to hereafter as ―NRC".)

- Pascual, P., N. Stiber, and E. Sunderland, (2003) Draft Guidance on the Development, Evaluation, and Application of Regulatory Environmental Models, US Environmental Protection Agency, Council on Regulatory Environmental Models: Washington, DC. (Referred to hereafter as ―DG".)

EPA established the Council for Regulatory Environmental Modeling (CREM) in 2000 to improve and support the use of models at the agency. The three guidance documents (NRC, SAB, and DG) reviewed herein stem from work by or commissioned by the CREM. The background for each study is discussed below.

C.1.2. Review Scope

After a brief introduction to the documents reviewed, we discuss the main themes presented in the three modeling guidelines, namely:

- Model selection

- Model application: extrapolation, limitations, assumptions

- Model ―life-cycle plan‖ rather than static test-it-once-use-it-forever approach.

- Transparency and accountability

- Peer review, model evaluation

- Analysis and presentation of uncertainty

Finally, we review the modeling done in the draft RIA in view of these guidelines.

C.2 Draft Guidance on Regulatory Environmental Models

EPA issued this draft guidance in 2003 in response to a request by EPA administrator Christine Whitman to the CREM. The recommendations presented are drawn from EPA‗s own white papers, EPA‗s Science Advisory Board reports, and peer-reviewed literature. The draft organizes its recommendations around three themes:

- Model development: identifying the issues the model will address, developing the conceptual and mathematical models, and parameterizing the model;

- Model evaluation: determining whether a model and its outputs are of sufficient quality to support decision-making; and

- Model application: achieving ―transparency‖ by documenting model parameters and behavior, and effectively communicating uncertainty.

The forward to the draft notes that its recommendations are not legally binding, and may not apply all situations. Rather, EPA may diverge from these recommendations as required in specific cases.

Note: it does not appear that EPA ever issued a final version of this report.

C.3 Review by Science Advisory Board of EPA Draft Guidance

The EPA Regulatory Environmental Modeling (REM) Guidance Review Panel of the Science Advisory Board completed a review of the Draft Guidance in 2006.[15]

Although API requested that Life Cycle Associates examine this document, the SAB review is of only minor importance: what matters more is the draft itself. The draft identifies the features and analyses that the modeling underlying EPA rulemaking should seek to attain. The SAB review is merely that—a review of this work, and it is generally favorable.

---

[15] The SAB also reviewed the *Models Knowledge Base*, however we restrict our analysis here to the review of the Draft Guidance.

The few places where the SAB review makes concrete recommendations generally pertain to the handling of uncertainty. These are discussed in Section C.3.

C.4 National Research Council Study on Modeling in the Regulatory Process

At the request of the CREM, the National Research Council (NRC) convened the Committee on Models in the Regulatory Decision Process to independently assess scientific and technical issues related to the use of computational and statistical models at EPA, resulting in this report, published in 2007 [1]. This 267-page report is far more comprehensive than either the 60-page Draft Guidance, or the 76-page review of that draft. It follows a similar structure to the Draft Guidance, however, with the main substantive sections focused on model development, model evaluation, and model selection and use.

C.5 Review of Recommendations

C.5.1. Model Selection

Model selection involves the decision about which model is most appropriate to use in any given situation. The NRC notes that models generally do well only what they were designed to do, and when operated within design constraints. Therefore it is essential to evaluate any model, its assumptions, and its data in the specific context in which it will be used, and to understand the range of conditions to which the model can reasonably be applied.

These concerns are relevant to the use of GREET by EPA. For the purposes of the RIA, the use of GREET is reasonably appropriate, since the model is designed to assess ―average‖ fuels. However, for the RIA, EPA attempts to use GREET to perform a marginal analysis focused on new biofuels production facilities. The structure of GREET doesn't allow this type of analysis to be conducted accurately, due to circular computations which cause the marginal biofuels modeled to used pervasively in the model. For example, all gasoline that is blended with ethanol and used for transportation of goods anywhere in the model uses the same marginal ethanol being modeled. To accurately model specific fuel pathways (marginal or otherwise) in GREET would require modifications to the model structure.

The NRC also notes that determining the appropriateness of a model to any situation requires adequate documentation for both potential users and those reviewing the model selection decision. Neither GREET nor do the economic models being contemplated for the EPA rulemaking have documentation that meets these standards.

C.5.2. Transparency and Accountability

Model transparency enables the user and reader of the analysis to understand the inputs and fundamental workings of the model. Transparency is typically accomplished through documentation, clear description of inputs, definition of calculation routines, and other means of thoroughly describing the model.

The NRC recommends maintaining a record of important events in the history of a model, such as major assumptions, decisions and changes across software version releases, and prior expert reviews of the model or model components. This type of documentation contributes to the transparency of the model and allows reviewers to better understand the appropriateness of the model to the task at hand.

GREET does not include documentation of the changes from version to version. The most recent complete documentation dates back to version 1.5 in 1999. There has not been comprehensive documentation of the changes leading to the current version, 1.8, although new pathways have generally been documented in peer-reviewed papers as they've been implemented.

The NRC says ―In the regulatory environment, EPA has the responsibility to ensure that a model's development and use is transparent. Because modeling is often a very technical exercise, EPA faces a challenge in making all of the underlying decisions intertwined within a model intellectually accessible to a nontechnical audience." Similarly, the Draft Guidance says ―[m]odel transparency is achieved when modeling processes are documented with clarity and completeness at an appropriate level of detail. When models are transparent they can be used effectively in a regulatory decision-making process."

Making a highly technical model accessible to nontechnical audiences sets a very high bar. It is likely that few sophisticated models meet this criterion. However, clear and complete documentation is obviously essential to understand a model and its limitations. Unfortunately, neither GREET nor the FAPRI model achieve this standard.

The NRC also recommends that EPA ensure that stakeholders have access to models it uses. This is probably not going to happen with the FAPRI model, which will likely play an important role in EPA's estimation of LUC for biofuels. (The GTAP model does meet this requirement, suggesting that it might have been a better choice for regulatory modeling.)

C.5.3. Model Life Cycle Plan"

The model life cycle includes the planning, design, development, use, and ongoing maintenance of model. The NRC suggests that EPA develop a life-cycle model evaluation plant for all models it uses in regulatory processes. These plans should, at a minimum:

- ―Describe the model and its intended uses.
- Describe the relationship of the model to data, including the data for both inputs and corroboration.
- Describe how such data and other sources of information will be used to assess the ability of the model to meet its intended task.
- Describe all the elements of the evaluation plan by using an outline or diagram showing how the elements relate to the model's life cycle.

- Describe the factors or events that might trigger the need for major model revisions or the circumstances that might prompt users to seek an alternative model. These could be fairly broad and qualitative.
- Identify responsibilities, accountabilities, and resources needed to ensure implementation of the evaluation plan. ―

C.5.4. Model Complexity

Model complexity tends to grow over time as modelers add features and details to a model. Increasing complexity, however, generally reduced transparency. The DG recommends that models be no more complex than necessary to meet regulatory goals. The DG also notes that although parsimony is a desirable modeling trait, ―care should be taken not to eliminate important parameters from process-based models simply because data are unavailable or difficult to obtain." [2] This argues for the inclusion of indirect land use change in the life cycle assessment of biofuels.

C.5.5. Model Application: Extrapolation, Limitations, Assumptions

Model application involves the use of a model in a specific context. A model application concern noted by the NRC is *extrapolation*, or applying a model beyond the range appropriate to the data or assumptions underlying the model.

"Extrapolating far beyond the available data for the model draws particular attention in the evaluation process to the theoretical basis of the model, the processes represented in the model, and the parameter values. When critical model parameters are estimated largely on the basis of matching model output to historical data, care must be taken to provide uncertainty estimates for the extrapolations, especially for models with many uncertain parameters." [1]

It is also unclear how well the economic models used for estimate land use changes handle large excursions from equilibrium; these changes may well be outside the range supported by the underlying econometric data or estimates of elasticities upon which this class of models depends.

C.5.6. Ensemble Modeling

In some cases, the SAB review suggests ensemble modeling, i.e. running the same scenarios through a functionally equivalent set of models, creating a composite of the results. This may be a good approach for LUC modeling since there are a range of models using different techniques and assumptions that attempt to estimate this effect. It is unclear which, if any of these, has the best approach, or whether the models are in reasonable agreement.

However, this approach is not really possible for the fuel cycle modeling, given the small number of models available (e.g. GREET, LEM, GHGenius.) In this case, the models are much simpler, and the basic approaches taken are fairly similar. While the LEM is not available to the public and has not undergone *any* peer review, GHGenius, which is based on a 1999 version of the LEM, *is* publicly available, and would provide a suitable comparison to GREET. The methods therein are similar to those used in GREET, so synchronizing the data assumptions

should result in similar results. It would be useful to compare data to ensure that GREET is as up-to-date as GHGenius (which, in general, appears to be better documented.)

C.6 Peer Review and Model Evaluation

Both the NRC and EPA's own guidelines recommend external peer review of models used in rulemaking with significant economic effects. An important point is that reviewing the model generically is insufficient: the model must be reviewed in the context in which it is to be applied, as a model may be called on to do more than it was designed to do, or more than the data supports. This latter issue is relevant to the GREET model, which is designed to compute the energy use and emissions for a variety of *average* fuels. The model is not designed to model *specific* fuel pathways without structural modification.

The NRC writes: ―A peer review is so basic to model quality and its acceptance that it must be excellent in substance, as well as appearance. Therefore, careful attention must be given to the three foundations of selecting peer reviewers: scientific qualifications, conflicts of interest, and balance of bias."

The NRC also writes that ―[e]valuation of regulatory models also must address a more complex set of trade-offs than evaluation of research models for the same class of models. Regulatory model evaluation must consider how accurately a particular model application represents the system of interest while being reproducible, transparent, and useful for the regulatory decision at hand. Meeting these needs may require different forms of peer review, uncertainty analysis, and extrapolation methods."

The Draft Guidance defines model evaluation as ―the process used to generate information to determine whether a model and its analytical results are of a quality sufficient to serve as the basis for a decision." [2] (They contrast this with model *validation*, which is essentially impossible given the approximation of reality inherent in modeling: no model can be valid, i.e. precise and accurate, for all applications.) The guidance also states that ―model quality is an attribute that is meaningful only within the context of a specific model application." [2]

The Draft Guidance also recommends that a model undergo thorough peer review (at least) in its first regulatory application, but thereafter, only the novel aspects of its application need to be reviewed. The DG states,

"Aspects of a model that should be reviewed in this process to establish scientific credibility are: (a) appropriateness of input data, (b) appropriateness of boundary condition specification, (c) documentation of inputs and assumptions, (d) the applicability and appropriateness of using default values, (e) documentation and justification for adjusting model inputs to improve model performance (calibration), and (f) model application with respect to the range of its validity, (g) supporting empirical data that strengthen or contradict the "conclusions" that are based on model results."

It is not clear whether the GREET, FASOM-GHG, or FAPRI models have ever undergone the type of peer review envisioned here. In the case of GREET, EPA's own review of the model constitutes a form of peer review, but an independent review would be preferred. The FASOM-GHG and FAPRI models may not be available for peer review; these models are run by their developers and scant documentation is available. (In contrast, the GTAP computable general equilibrium model, in use in other parts of EPA, is widely disseminated and well-documented.)

In applying economic equilibrium models to fuel and GHG regulation, EPA is utilizing a new set of models to evaluate a novel concept, using untested methodologies. A transparent and unimpeachable peer review of these models and methodologies will be required to achieve the buy-in described above by stakeholders and the courts.

C.6.1. Model Evaluation

Model evaluation involves reviewing a model to determine how well it is performing in the context in which it is being applied. The NRC recommends against using the term —validation" since complex models can never match reality and therefore can't be validated, only —invalidated." They suggest, therefore, that the preferred term of art is model —evaluation".

Although —validation" is impossible, the Draft Guidance notes that model code can and should be —verified" to perform according to its design specifications. Code verification is quite tedious in large spreadsheet models such as GREET due to the obfuscating nature of cell references, the large number of redundant calculations, and the very large potential for undiscovered errors. This, in fact, is a reason to prefer models written in higher-level languages to spreadsheet models. Despite years of use of GREET by many users, Life Cycle Associates recently discovered several mathematical errors in the model. It is not possible to verify the code in the FAPRI model since it is not publicly available.

Evaluation is difficult for both GREET and the various LUC models, for different reasons. The components of the LUC models are more easily tested in isolation, e.g. the economic portion, the allocation of changes to specific ecosystem types, and the carbon loss functions. These can be compared against historical or survey data to (at least) validate the range of uncertainty.

A fundamental problem with both GREET and LUC modeling is that neither type of model can be effectively corroborated. GREET deals in an abstraction, i.e. the life cycle energy use and emissions from the production and use of some fuel and/or vehicle. This is not an inherently measurable quantity, but one that must be modeled. LUC estimates based on economic equilibrium modeling are not abstract, but they are unverifiable: the assumptions that underlie the model theory are known to be false; equilibrium never obtains in reality; and the real world violates the *ceteris paribus* assumptions surrounding the dynamics appearing in the model.

With GREET, evaluation can consist of verifying that the chosen methodology has been applied consistently as stated and that fuel pathway analyses are commensurate in terms of system boundaries, time horizons, geographical boundaries, and data resolution.

While recognizing that there is no established set of model acceptability criteria, the NRC suggests that the following factors should be addressed in the model evaluation process:

- **Scientific pedigree**: origin and quality of concepts and theories behind the model and its constituent parts

- **Model structure and components**: a diagram and brief description of the major components of the model

- **Model capabilities and limitations**: should include inputs required to run the model, outputs provided by the model, space and time scales to which the model applies, substances that the model addresses, and key sensitivities and uncertainties.

- **Model performance evaluation**: when appropriate (and possible) models should be shown to match field observations; model comparisons may be sufficient in the absence of such data.

- **Parsimony**: how the developers arrived at the level of detail represented in the model, and how this relates to the ―optimal precision‖ required by the regulations at hand.

- **Peer review**: especially useful for determining model applicability.

How these factors are addressed will vary by model type and policy context.

C.6.2. Model Review

The NRC recommends that the public and stakeholders have greater opportunity to review and suggest improvements to models than is available in the usual 60-day review period:

―It is important that EPA institute best practice standards for the evaluation of regulatory models. Best evaluation practices may be much easier for EPA to implement if its resulting rigorous life-cycle evaluation process is perceived as satisfying regulatory requirements, such as those of the Information Quality Act. However, for an evaluation process to meet the spirit and intent of the Information Quality Act, EPA‘s evaluation process must include a mechanism for any person to submit information or corrections to a model. Rather than requiring a response within 60 days, as the Information Quality Act does, the evaluation process would involve consideration of that information and response at the appropriate time in the model evaluation process.‖

C.7 Uncertainty

C.7.1. Model Uncertainty

The NRC writes that ―[m]odel uncertainty relates to whether the structure of the model fundamentally represents the system or decision of interest.‖ [1] In economic models of land use, there are fundamental questions about whether equilibrium modeling is representative of the real world, given that (a) competitive market assumptions underlying the economic theory itself are widely violated in the real world, (b) multiple equilibria may exist (i.e. there is not a unique solution), and in any case, (c) equilibrium doesn‘t really obtain in the real world [3]. Economic equilibrium models are, however, still the best tools currently available for estimating market-

based effects such as induced land use change. The large uncertainties in any result, however, must be addressed.

In the case of fuel cycle models, there is model uncertainty inherent in the choice of which emissions and biogeochemical affects to consider part of the life cycle GWI of a fuel. Most models look at CO_2, CH_4, and N_2O, and several also consider the global warming potentials of CO and VOCs (e.g. in GREET, these are each assumed to be converted to CO_2 at a certain rate.)

Another more fundamental question is how to treat carbon equivalence. The IPCC recommendation for national inventories is to use 100-year global warming potential (GWP) values. However, if one believes that a tipping point may be reached in the next 1-2 decades, the shorter time horizons may be more informative and appropriate.

C.7.2. Corroboration, Sensitivity Analysis, and Uncertainty Analysis

Sensitivity analysis examines the sensitivity of model results to small perturbations in individual model parameters. Since parameters are perturbed one-by-one, this is a ―local‖ analysis, i.e. it doesn't consider the impact of multiple, simultaneous parameter perturbations. In contrast, uncertainty analysis examines the contribution of individual parameters to the uncertainty in the model output.

The LUC (economic) models involve an unquantifiable level of model uncertainty. GREET involves less model uncertainty, given the simpler nature of the life cycle methodology. Both types of models involve abundant data uncertainty as well, i.e. that caused by ―measurement errors, analytical imprecision and limited sample sizes during the collection and treatment of data.‖ In addition, variability affects both types of models, e.g. in N_2O emissions and economic parameters such as exchange rates and elasticities. Variability ―results from the inherent randomness of certain parameters that is attributable to the heterogeneity and diversity in environmental processes‖, and is affected by the degree of aggregation in the model. Data uncertainty is ―reducible‖ uncertainty, while variability is irreducible.

Application niche uncertainty affects both types of models, but the economic models in particular, as the size of demand shocks that drive the analyses may be well outside the range of econometric data (in the case of FAPRI) or measured elasticities (in the case of FASOMGHG.) The DG states:

―*A model's application niche is the set of conditions under which the use of a model is scientifically defensible. Application niche uncertainty is therefore a function of the appropriateness of a model for use under a specific set of conditions. Application niche uncertainty is particularly important when choosing among existing models for an application outside of the system for which it was originally developed and/or developing a larger model from several existing models with different spatial or temporal scales.*‖ [2]

The NRC writes that modelers ―should take care to estimate, quantify, and communicate uncertainties accurately to users and regulators. Any limitations in temporal or spatial scales

should be stated clearly. The quality of the input data and the resulting limitations on the range of use for the model should be explained in terms of the intended use of the model. Sensitivity to alternative inputs or assumptions should be documented."

The NRC also notes that besides a Regulatory Impact Analysis (RIA) for rules exceeding $100 million in economic effects, ―rules exceeding $1 billion per year in economic effects are subject to a further requirement to include a formal analysis of uncertainty." [p. 68] An 36 billion gallon RFS clearly exceeds this monetary impact threshold, thereby triggering the formal uncertainty analysis, presumably for all the models involved.

C.7.3. Quantifying Uncertainty

According to the NRC, where the model approach is uncontroversial (e.g. the process portion of most fuel pathways) a probabilistic treatment of key parameters is possible and helpful. For the LUC analysis, however, the methodologies themselves are not obvious. The best approach in this case is a hybrid combining scenario analysis (for different model forms) with probabilistic analysis.

GREET's Monte Carlo analysis (at least as described in Brinkman [5]) doesn't begin with the recommended sensitivity analysis. Instead, GREET has some 700 parameters for which probability distributions have been defined, though the criteria for making a parameter stochastic is not stated. In addition, there isn't any discussion of correlated uncertainties in the Brinkman (2005) analysis. A Monte Carlo analysis that fails to consider correlations between parameters will tend to over-estimate the uncertainty of the result due to choosing incompatibly broad pairs of parameters that actually vary together.

C.7.4. Communicating Uncertainties

The NRC says:

"Policy makers need to be informed explicitly of the impacts of changing assumptions about highly uncertain parameters in a technical analysis; these impacts should not be buried in the analysis."

The SAB report recommends that ―…the Draft Guidance should stress the importance of communicating model sensitivity and uncertainty both in the context of model evaluation and when interpreting and applying model outcomes in the context of decision-making."

"It is useful to qualitatively or quantitatively specify the acceptable range of uncertainty during the problem identification stage. Uncertainty is the term used in this guidance to describe lack of knowledge about models, parameters, constants, data, and beliefs. Defining the ranges of acceptable uncertainty helps project planners generate "specifications" for quality assurance planning and partially determines the appropriate boundary conditions and complexity for the model being developed." [2]

Uncertainty is not quantified in the RIA. Nor is any acceptable level of uncertainty identified.

The NRC writes:

"Effective decision making will require providing policy makers with more than a single probability distribution for a model result (and certainly more than just a single number, such as the expected net benefit, with no indication of uncertainty). Such summaries obscure the sensitivities of the outcome to individual sources of uncertainty, thus undermining the ability of policy makers to make informed decisions and constraining the efforts of stakeholders to understand the basis for the decisions."

The report is written as if the model produces a result a decision-maker reviews, rather than a result that is used to decide mechanistically whether a fuel production pathway meets a regulatory requirement such as a quantified reduction in life cycle GHG emissions compared to gasoline. The importance of explicitly examining uncertainty is undiminished in the latter case, however, the manner in which to best incorporate uncertainty into the regulation is not obvious.

At the least, EPA should provide an estimate of the uncertainty in its estimation of the life cycle GHG impacts (including LUC) for each fuel pathway modeled, and it should discuss the key parameters for each pathway that drive the magnitude and uncertainty of each result. In addition, EPA should indicate how it intends to incorporate uncertainty into the performance requirements for different biofuels under the updated RFS.

C.8 Regulatory Impact Assessment for RFS2 under EPACT 2008

The Renewable Fuel Standard, for which the DRIA was performed, examines the net change in GHG emissions that can be expected due to the RFS. It examines renewable fuels only as well as petroleum pathways in GREET with modification.

We reviewed the DRIA [4] with two goals: (1) to see how the use of modeling in the RIA compares to the guidelines discussed above, and (2) to anticipate some of the issues that may present in the modeling for the new rulemaking.

Overall, EPA has given reasoned consideration to the important issues in fuel life cycle analysis, and made defensible decisions appropriate to the task. One significant exception—land use change—is discussed at length, and this gap is attributed to a lack of appropriate analytic tools. EPA notes in several places its intention to continue its research in these areas for future analyses. EPA has clearly attempted to close this gap in its 2009 DRIA.

EPA notes that, unlike many fuel cycle studies, their ethanol analysis is prospective, not retrospective, and therefore focuses on marginal production from new, efficient dry-mills, and anticipates increases in corn yield.

EPA moves into a consequential LCA with the 2009 DRIA. This analysis moves away from the mostly average inputs (with some marginal estimates) to an economically driven assessment. While this method may not exactly represent the reductions associated with the implementation of 36 Bgal of renewable fuel, it is reasonable for the purpose of this analysis which is to determine the impact of the total increased volume of renewable fuels used.

For this purpose, the GREET model is appropriate, as it is designed to model the average fuel from each pathway. For example, the ―average‖ ethanol appears as an oxygenate in the typical gasoline blends that are used for transportation whenever gasoline is assumed.

The analysis computes the GHG savings from biofuels and then applies this to the GHG inventory for the transportation sector. However, this inappropriately mixes life cycle analysis with sectoral analysis. The problem is that life cycle analyses—by definition and intention—are cross-sectoral. The study treats the savings due to biofuels as attributable to the transportation sector, yet much of the increased activity is in the agricultural sector under a sectoral perspective. For petroleum fuels this doesn‘t much matter since most of the climate impact of these fuels is due to the carbon in the fuel itself. However, for biofuels, 100% of the GHGs are emitted in upstream processes, which overlap with (in the case of corn ethanol plants) or are entirely within (in the case of crop production) within the agricultural sector.

The document describes the corn ethanol analysis in great detail, but fails to provide a similar level of detail on the cellulosic ethanol and biodiesel analyses. In particular, there is no discussion of the assumptions underlying projections of conversion processes for cellulosic ethanol, energy use in cellulosic feedstock production, or co-product allocation in the case of soybean biodiesel.

C.9 Conclusions

The use of GREET meets many of the recommended guidelines, but as of this writing, two major gaps remain: documentation is scarce, and EPA has not performed any uncertainty analysis. In addition, some critical exogenous parameters, e.g. corn farming energy, do not meet the transparency requirement, and cannot be duplicated.

The use of economic models to estimate the LUC effect fails to meet many of the guidelines, due to lack of transparency and lack of uncertainty analysis. The GTAP model might be a better choice for both of these reasons.

The modeling of indirect LUC is particularly troublesome. We know this effect occurs, and that the impacts on climate are quite possibly much larger than the benefits of substituting certain biofuels for their fossil counterparts. Yet the results are highly contingent on assumptions that have multiple plausible values (e.g., the period over which to amortize the initial carbon loss.) Therefore, there is no single, deterministic answer to this question, and any attempt to quantify the LUC effect in regulation is bound to be highly controversial. The NRC notes that ―EPA has had several environmental regulations overturned because, in the opinion of the courts, the model was considered to be so inaccurate that the regulation was deemed ―arbitrary and

capricious." To know which biofuels are beneficial or detrimental to the climate requires that we get the LUC question right, however, it may be difficult to do so in a manner that is not arbitrary.

C.10   Model Evaluation References

1. NRC, Models in Environmental Regulatory Decision Making. 2007, Committee on Models in the Regulatory Decision Process of the National Research Council.
2. Pascual, P., N. Stiber, and E. Sunderland, Draft Guidance on the Development, Evaluation, and Application of Regulatory Environmental Models. 2003, US Environmental Protection Agency, Council on Regulatory Environmental Models: Washington, DC.
3. DeCanio, S.J., Economic Models of Climate Change: A Critique. 2003, New York: Palgrave McMillan. 203.
4. US EPA, Regulatory Impact Analysis: Renewable Fuel Standard Program. 2007, Assessment and Standards Division, Office of Transportation and Air Quality, U.S. Environmental Protection Agency: Washington, DC.
5. Brinkman, N., et al. (2005). Well-to-Wheels Analysis of Advanced Fuel/Vehicle Systems -- A North American Study of Energy Use, Greenhouse Gas Emissions, and Criteria Pollutant Emissions. General Motors and Argonne National Laboratory.

D   Issues with Using GREET to Perform Life Cycle Analyses

There are a number of issues surrounding the use of GREET in performing transportation fuel life cycle analyses. These are listed in the following.

General

1. Examine all fuel properties. Inspect fuel carbon intensity (g C or CO_2/MJ)
2. System boundary diagrams should be drawn for every fuel pathway to reflect inputs and fate of co-products (Edwards, Wang biodiesel report)

Petroleum and Fossil Fuels

1. A 750 mi hydrogen pipeline is used for petroleum and biofuels inputs
2. GREET includes energy required to make natural gas in WTT calculation for hydrogen. Currently GREET only includes the energy for the natural gas fuel cycle, not the natural gas itself.
3. Emission factors for hydrogen reformer combustion are based on natural gas combustion. Hydrogen reformers burn spent synthesis gas with lower CH_4 emissions (Pont).
4. Hydrogen production efficiency is too high but hydrogen production with steam export to refinery is not considered, probably offsetting the effect. Hydrogen production efficiency also affects renewable diesel pathways.
5. GREET calculations for refinery emissions from oil sands production depend on GHG intensity of crude oil production. This calculation is illogical since synthetic crude oil requires less energy to refine than conventional crude oils.
6. Refinery emissions are averaged with refinery emissions from oil sands pathway. However, GREET already bases refinery energy inputs and emission calculation on aggregate data from EIA. Thus, combined refinery calculation for oil sands pathway should be eliminated.
7. Refinery allocation method needs a sounder basis. Review Jacobs, JRC, TIAX/MathPro, Teherani.
8. Crude resources and related transport distance and modes should be recalculated based on EIA data. Not all crude oil tankers have a 1,000,000 DWT capacity as inputted to GREET. The crude oil location, pipeline distance, route, and vessel capacity could be calculated (this is only a 1 g CO2e/MJ effect).

Ethanol and Agricultural Inputs

1. GREET does not include the additional transport energy for ethanol delivery required by today's and future segregated infrastructure. An additional 50 miles of truck transport should be added. This mileage is counted in the LCFS.
2. No sugar cane pathway for dehydration with fuel oil in the Caribbean is evaluated

3. No cellulosic ethanol pathway for systems with high material inputs like nitric acid are evaluated

4. Treatment of direct land use emissions in FASOM is unsatisfactory given the enormous change in carbon involved. GREET defaults do not address the carbon flux of biofuels any better.

5. Life cycle for limestone is the same as that for K_2O in GREET. Limestone is strip mined in Florida while Potash is shaft mined in Saskatchewan. (Grabowski)

6. Life cycle for ammonia and urea are not well documented. Pathway for both nitrogen fertilizers are based on natural gas. Coal fertilizer is not included. However, a consequential LCA should take coal fertilizer into account.

7. Co-product power from biofuels may be sold to meet renewable obligations so no credit should be given in a consequential LCA

8. Co-product power associated with biomass residue for should not be attributed to ethanol to avoid gearing (Lafevre). The gearing issue is not addressed. GREET has a co-product power credit for
    a. Sugar cane ethanol
    b. Herbaceous biomass to ethanol and FTD
    c. Farmed trees to ethanol and FTD

9. GREET provides a credit for DGS based on corn and soybean meal. While not used in EPA's DRIA, the empirical credit from FASOM should be derived and compared. ARB's LCFS provides a credit of 1:1 of corn to DGS for a number of reasons

10. FASOM should recognize scenarios when DGS is burned for fuel, which is a GREET pathway.

11. While not used in the DRIA, Ag inputs for GREET are based on 2000 USDA data. The farming energy, fertilizer use, and other factors are extrapolated downward based on unsubstantiated ANL projections.

12. USDA has stopped collecting farm energy input data which is critical for assessing the life cycle inputs for biofuels.

13. Energy inputs for collection of forest residue appear high and do not match process calculations from forestry studies (Riffel)

14. GREET calculates a soil carbon credit for some biofuels pathways (farmed trees, herbaceous biomass) but shows no credit for forest residue, which is treated as perfectly carbon neutral. This issue is not addressed in the DRIA at all since FASOM does no address forestry nor does it address removal of bark beetle damaged forest. While not used in the DRIA, the implied precision in GREET is suspect.

Biodiesel

1. Glycerin production from biodiesel is 0.1 kg/kg not 0.21

2. System wide ANL allocation method for biodiesel in GREET assigns soybean meal benefit to glycerin production. This method is not appropriate based on our survey of stakeholders and experts. The allocation should be applied separately for each process.

3. GREET does not include fossil fuel carbon from methanol in soy biodiesel. Ignoring the fossil fuel carbon combines a substitution credit with an allocation approach, thus double crediting. The fossil carbon in biodiesel is 3.7 g CO_2/MJ.
4. Co-product credit for substitution method in GREET assumes that soybean meal has 1.2x value of soybeans. While not used in EPA's DRIA, it should be recognized that this factor is not substantiated and will vary with production volume.
5. Use of tallow as biodiesel feed eliminates it as a source of boiler fuel or animal feed

Biomass to FT fuels

1. Thermochemical based conversion plants will likely be at a larger scale than fermentation based technologies because of the requirements of economy of scale. The impact may result in larger transport distances. However, such plants may be co-fed with coal or waste material. GREET calculates a mix of coal and biomass. However, it is not clear how such a mix would be treated under EISA. Would the coal portion of the feedstock be treated separately?
2. GREET assigns a natural gas combustion emission factor to synthesis gas combustion. This is not a good choice because synthesis gas contains very little CH_4.