NATIONAL ENERGY TECHNOLOGY LABORATORY

Life Cycle Analysis: Ethanol from Biomass

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LIFE CYCLE ANALYSIS: ETHANOL FROM BIOMASS

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ACRONYMS AND ABBREVIATIONS

°C	Degree Celsius
°F	Degree Fahrenheit
AEO	Annual Energy Outlook
ANL	Argonne National Laboratory
ASTM	American Society for Testing and Material Standards
BTL	Biomass To Liquids
Btu	British Thermal Unit
CAP	Criteria Air Pollutant
CARB	California Air Resource Board
$CaCO_3$	Limestone
CBTL	Coal and Biomass to Liquids
CCF	Capital Charge Factor
CCS	Carbon Capture and Sequestration
C/D	Commissioning/Decommissioning
CH_4	Methane
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO_2e	Carbon Dioxide Equivalent
CTL	Coal to Liquid
DBD	Design Basis Document
DDG	Dried Distillers Grain
DDGS	Dried Distillers Grains with Solubles
DG	Distillers Grains
DOE	Department of Energy
DRIA	Draft Regulatory Impact Analysis
E10	10 Percent Ethanol/90 Percent Gasoline
E85	85 Percent Ethanol/15 Percent Gasoline
EIA	Energy Information Administration
EPA	Environmental Protection Agency
EROI	Energy Return on Investment
F-T	Fischer-Tropsch
FBC	Fluidized Bed Combustion
GHG	Greenhouse Gases
GREET	Greenhouse Gases, Regulated Emissions, & Energy use in Transportation Model
GWP	Global Warming Potential
H_2	Hydrogen

H_2S	Hydrogen Sulfide
HCI	Hydrochloric Acid
HF	Hydrogen Fluoride
Hg	Mercury
HHV	Higher Heating Value
hrs	Hours
IISI	International Iron and Steel Institute
I-6	Illinois No. 6
IKP	University of Stuttgart
IPCC	Intergovernmental Panel on Climate Change
ISO	International Organization of Standardization
kg	Kilogram
km	Kilometer
kW	Kilowatt
kWh	Kilowatt-Hour
lb	Pound
LC	Life Cycle
LCA	Life Cycle Analysis
LCC	Life Cycle Cost
LCI	Life Cycle Inventory
LCIA	Life Cycle Impact Assessment
LHV	Lower Heating Value
MACRS	Modified Accelerated Cost Recovery System
MBPD	Thousand Barrels Per Day
MGY	Million Gallons per Year
MJ	Megajoule
MOVES	EPA's Motor Vehicle Emissions Simulator Model
MROW	Midwest Reliability Organization West
MSW	Municipal Solid Waste
MW	Megawatt
MWe	Megawatts (electric)
N_2O	Nitrous Oxide
NETL	National Energy Technology Laboratory
NGL	Natural Gas Liquids
NH_3	Ammonia
NO_X	Oxides of Nitrogen
NPV	Net Present Value
NREL	National Renewable Energy Laboratory

O&M	Operations and Maintenance
O_3	Ozone
ORNL	Oak Ridge National Laboratory
Pb	Lead
PM	Particulate Matter
PM_{10}	Particulate Matter (diameter 10 micrometer)
$PM_{2.5}$	Particulate Matter (diameter 2.5 micrometer)
ppm	Parts per Million
ppmv	Parts per Million Volume
psia	Pounds per Square Inch Absolute
PV	Present Value
R&D	Research and Development
RDS	Research and Development Solutions
RFS2	EPA's Renewable Fuel Standards (revision 2)
RSP	Required Selling Price
SO_2	Sulfur Dioxide
SOC	Soil Organic Carbon
SOM	Soil Organic Matter
SO_X	Sulfur Oxides
SSCF	Simultaneous Saccharification with Co-Fermentation
TS&M	Transportation, Storage, and Monitoring
U.S.D.A.	US Department of Agriculture
UWW	Urban Wood Waste
VOC	Volatile Organic Chemical
WDG	Wet Distillers Grain

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EXECUTIVE SUMMARY

This report includes the results from two models: an environmental life cycle assessment (LCA), or cradle-to-grave inventory of emissions such as greenhouse gases and criteria air pollutants; and a life cycle cost (LCC) analysis, which is a discounted cash flow model which assumes a 30-year study period and tracks key capital and operations and maintenance (O&M) costs from acquisition of raw materials to the delivery of fuel to the consumer. The analysis provides a full life cycle comparison of three tiers of ethanol production technology (dry grind, biochemical conversion, and thermochemical conversion), three types of biomass feedstocks (corn grain, corn stover and switchgrass), and two fuel-blending compositions (E10 and E85) for a total of 18 distinct pathways[1].

Environmental LCA Results

The net global warming potential (in carbon dioxide equivalents, or CO_2e) for the E10 and E85 pathways are shown in **Figure ES-1** and **Figure ES-2**, respectively. The greenhouse gas (GHG) emissions include CO_2, methane, and nitrous oxide from fossil-fuel sources, biogenic carbon dioxide (CO_2) that is absorbed during biomass growth and released during the production and combustion of ethanol, and the GHG reductions due to the displacement of electricity. The net global warming potential of the ethanol pathways range from 0.021 kg CO_2e /MJ to 0.096 kg CO_2e /MJ, compared to 0.092 kg CO_2e /MJ for conventional gasoline. The uptake of CO_2 during biomass growth and reduction of CO_2 emissions due to the displacement of electricity (which occurs for the biochemical scenarios) are accounted for in the net CO_2e emissions.

Adding carbon capture and sequestration (CCS) to a dry grind facility does not significantly reduce CO_2e emissions as the majority of the emissions come from vehicle emissions, not from the conversion facility.

All E10 pathways fall within a CO_2e emission range of 0.090 kg/MJ and 0.096 kg/MJ. The range of CO_2e emissions for the E10 pathways coincides with the total life cycle emissions of conventional gasoline (0.092 kg CO_2e /MJ) as stated in NETL's baseline LCA of petroleum products (NETL, 2008). The composition of E10 is 90 percent gasoline (by volume), which explains why the CO_2e emissions of the E10 pathways are comparable to the gasoline CO_2e emissions from NETL's petroleum baseline. (The dashed, vertical line in **Figure ES-1** shows the CO_2e emissions from conventional gasoline.)

For the E85 cases, there is a far greater range of CO_2e results. All of the E85 cases show an improvement over conventional gasoline, with the biochemical conversion using corn stover as feedstock with the lowest overall CO_2e emissions. The biochemical ethanol plant studied in this analysis does not purchase fossil fuel-intensive energy (such as electricity or natural gas) (Aden *et al.,* 2002). Instead, the plant utilizes the unconverted portion of the biomass to produce heat and power for the process. The yield of ethanol from the biochemical technology could be

[1] E10 is a 10/90 volumetric split between ethanol and gasoline. The annual average composition of E85 is a 74/26 volumetric split between ethanol and gasoline in this analysis, which is a blending ratio that accounts for the higher share of gasoline used for cold-weather blends of E85 (EIA, 2009, p. 113).

increased if other energy sources are purchased and a biomass was converted to ethanol; however, adequate data are not available in the source documentation (Aden *et al.*, 2002) to perform this optimization. The trade-offs between different fuel sources used by the biochemical ethanol plant is beyond the scope of this analysis.

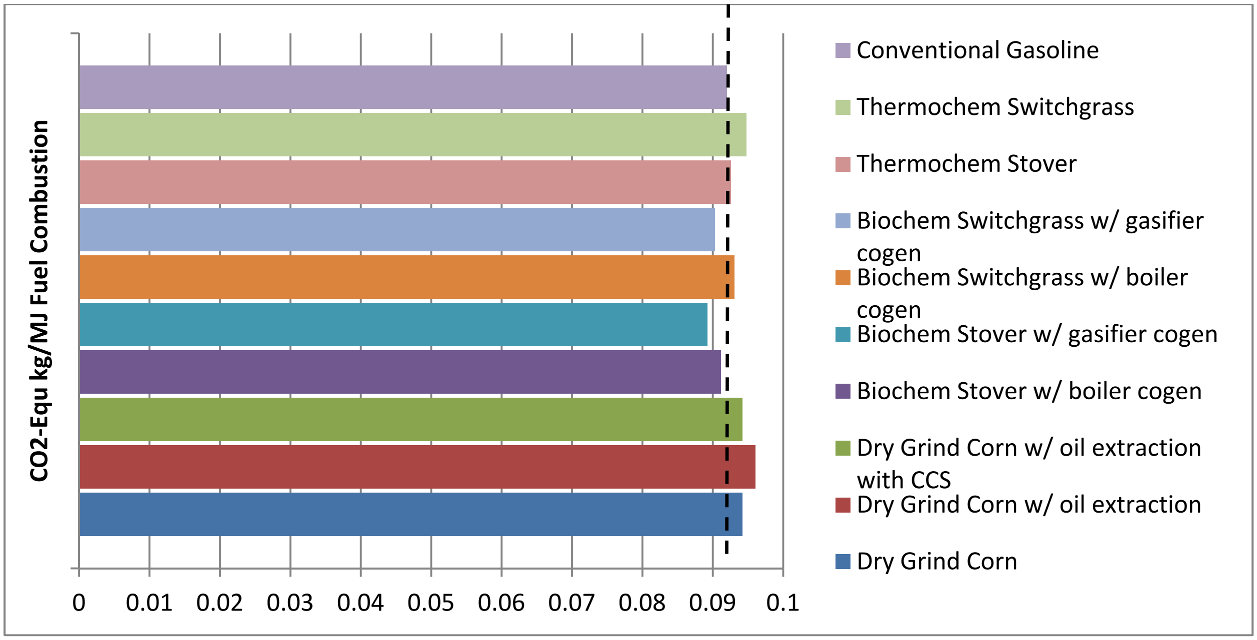

Figure ES-1: Net Carbon Dioxide Equivalents for E10 Pathways

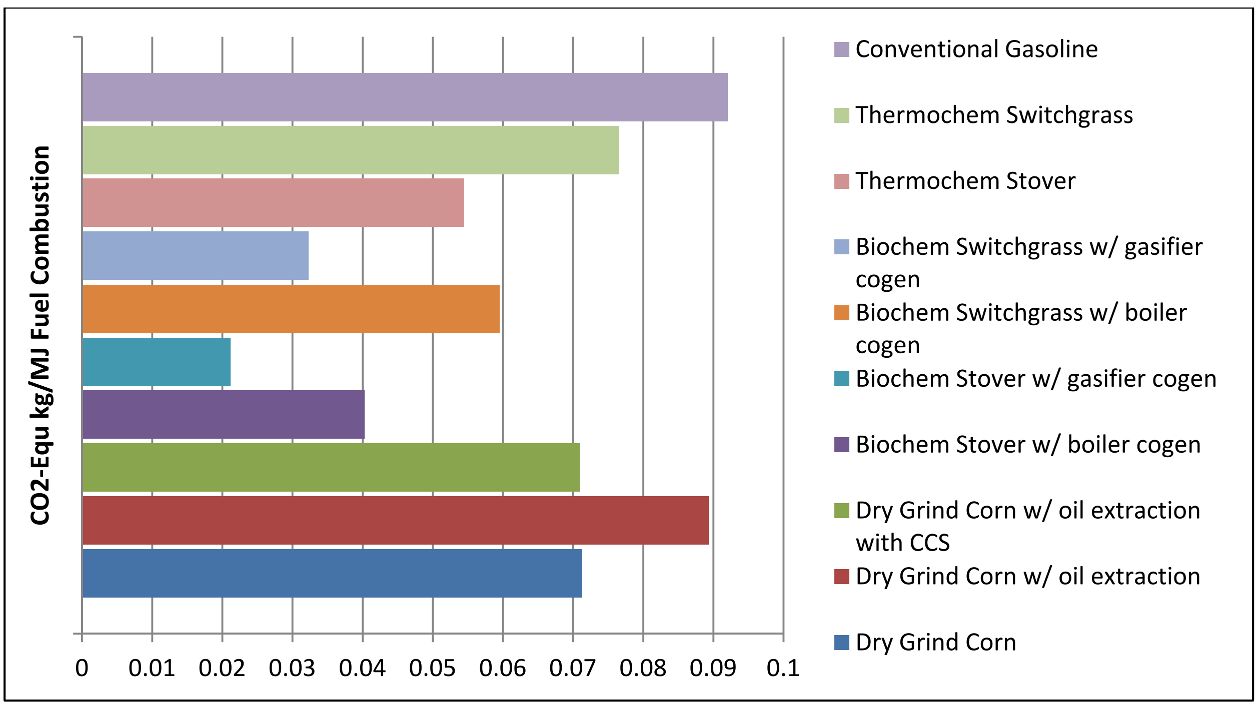

Figure ES-2: Net Carbon Dioxide Equivalents for E85 Pathways

Life Cycle Cost Results

The LCC calculates the required selling price (RSP), which is the minimum price at which ethanol must be sold in order to account for O&M, capital costs, and other costs related to the construction and operation of the fuel cycle. In this analysis, RSP is normalized to the heating value of gasoline, which enables the comparison of E10 and E85 on an equivalent energy basis, and provides a fairer comparison between ethanol blends and conventional gasoline. A gallon of gasoline has 1.03 times more energy than a gallon of E10 and 1.35 times more energy than a gallon of E85. The RSPs of E10 and E85 are multiplied by these factors in order to normalize them to the same energy basis of conventional gasoline. The RSP results for the E10 and E85 pathways of this analysis are shown in **Figure ES-3** and **Figure ES-4**, respectively.

The conventional ethanol dry grind process and the biochemical conversion of lignocellulosic biomass have the lowest RSPs, ranging from $3.00 to $3.50. The thermochemical pathway that uses corn stover for E85 production has the highest RSP of this analysis ($5.73 per gasoline gallon equivalent).

The results of the LCC analysis indicate that the bulk storage for E10 dominates the life cycle costs. *This does not mean that all of the gasoline costs occur at the bulk loading facility.* The cost model does not have the same level of detail for raw material extraction and raw material transport as the environmental model. The cost model tracks the *price* of gasoline entering the bulk loading facility; this price is by the bulk loading facility. All of the costs that are inherent in the price of delivered gasoline occur during the extraction, refining, and transport of gasoline; in this analysis, these costs are assigned to the bulk loading facility.

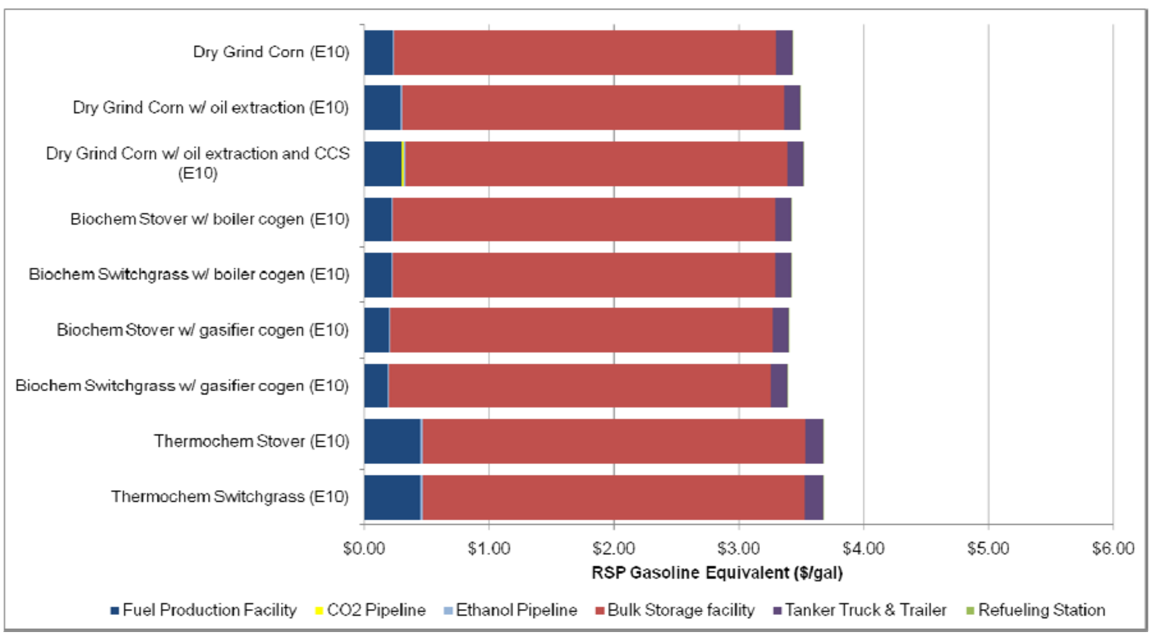

Figure ES-3: LCC Results by Life Cycle Stage for E10 Pathways

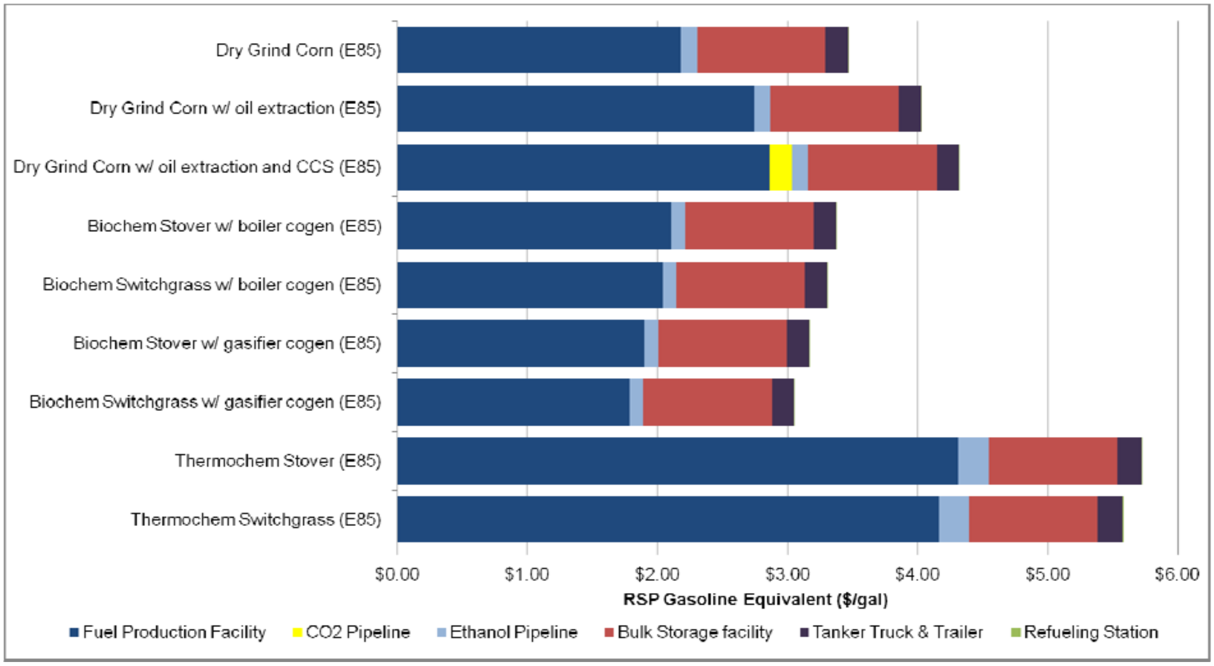

Figure ES-4: LCC Results by Life Cycle Stage for E85 Pathways

Key Conclusions

The technologies and metrics investigated provide a significant basis for comparing and contrasting different pathways for the production and use of E10 and E85. **Table ES-1** and **Table ES-2** depict the key results of this analysis.

Table ES-1: Results of Primary Study Metrics for E10

Conversion Technology	Feed-stock	CCS	RSP ($/gal gasoline equivalent)	NOx (kg/MJ)	VOC (kg/MJ)	PM10 (kg/MJ)	Water Withdrawal (kg/MJ)	Resource Energy (MJ/MJ)
Dry Grind	Corn	X	$3.43	2.48E-04	3.28E-04	8.28E-05	8.26	6.30E-02
Dry Grind w/ oil extraction	Corn	X	$3.49	2.47E-04	1.88E-03	8.31E-05	8.25	6.71E-02
Dry Grind w/ oil extraction and CCS	Corn	90%	$3.52	2.46E-04	3.41E-04	8.28E-05	8.25	6.71E-02
Biochem w/ boiler cogen	Corn Stover	X	$3.42	2.44E-04	2.01E-03	8.42E-05	4.43	1.32E-01
Biochem w/ boiler cogen	Switch-grass	X	$3.42	2.43E-04	8.13E-05	8.19E-05	17.42	1.54E-01
Biochem w/ gasifier cogen	Corn Stover	X	$3.40	2.42E-04	1.98E-03	7.99E-05	4.44	1.32E-01
Biochem w/ gasifier cogen	Switch-grass	X	$3.39	2.41E-04	5.17E-04	7.76E-05	17.43	1.54E-01
Thermochemical Gasification	Corn Stover	X	$3.68	2.39E-04	3.78E-03	7.99E-05	5.04	1.31E-01
Thermochemical Gasification	Switch-grass	X	$3.68	2.38E-04	1.66E-04	7.75E-05	17.73	1.36E-01

Table ES-2: Results of Primary Study Metrics for E85

Conversion Technology	Feed-stock	CCS	RSP ($/gal gasoline equivalent)	NOx (kg/MJ)	VOC (kg/MJ)	PM10 (kg/MJ)	Water Withdrawal (kg/MJ)	Resource Energy (MJ/MJ)
Dry Grind	Corn	X	$3.46	2.09E-04	2.52E-04	1.45E-04	61.53	6.32E-01
Dry Grind w/ oil extraction	Corn	X	$4.03	2.00E-04	5.17E-04	1.48E-04	61.41	6.72E-01
Dry Grind w/ oil extraction and CCS	Corn	90%	$4.32	1.93E-04	3.78E-03	1.45E-04	61.42	6.72E-01
Biochem w/ boiler cogen	Corn Stover	X	$3.37	1.77E-04	1.65E-04	1.59E-04	32.85	1.32E+00
Biochem w/ boiler cogen	Switch-grass	X	$3.30	1.63E-04	2.51E-04	1.36E-04	130.30	1.54E+00
Biochem w/ gasifier cogen	Corn Stover	X	$3.16	1.51E-04	5.16E-04	1.16E-04	32.93	1.32E+00
Biochem w/ gasifier cogen	Switch-grass	X	$3.05	1.44E-04	3.76E-03	9.33E-05	130.36	1.54E+00
Thermochemical Gasification	Corn Stover	X	$5.73	1.17E-04	1.66E-04	1.16E-04	36.56	1.32E+00
Thermochemical Gasification	Switch-grass	X	$5.58	1.16E-04	2.52E-04	9.18E-05	132.54	1.37E+00

The tables show that NO_x, VOCs and PM_{10} emissions from the E10 and E85 life cycles are not significant sources. Those and other findings are highlighted below:

- The majority of the NO_x emissions occur in the final life cycle stage – the combustion of fuel in a passenger vehicle.
- VOCs are significantly higher for the pathways that use corn stover due to the methanol emissions associated with the production of potassium fertilizer that is used to replenish nutrients after corn stover is removed from the field.
- Particulate matter (specifically, PM_{10}) is 58 percent higher for the E85 pathways than for E10 pathways due to the combustion of diesel by farm equipment during biomass production.
- Water withdrawal for the E85 cases is much greater than for the E10 cases. This is because the majority of the water consumption for the ethanol life cycle comes in the first stage - biomass production.
- The E85 pathways consume more *total* energy than do the E10 pathways[2]. However, E85 uses less *fossil* energy than E10.

Comparison to Other Studies

The GHG and energy results described in this report fit within the ranges of results from similar studies conducted by other LCA practitioners (Patzek, 2004; Wang, 2001; EPA, 2009; Kammen *et al.,* 2008). The ranges in life cycle greenhouse gas emissions among various LCAs are illustrated in **Figure ES-5** below[3]. The red bar in **Figure ES-5** shows the GHG results of this analysis. To allow comparability with other studies, the results shown in **Figure ES-5** are on the basis of pure ethanol and should not be compared directly with the E10 and E85 results of this analysis.

[2] The method of this analysis assigns a heating value to all raw material inputs, including fossil and biomass feedstocks. These heating values account for the energy content of the feedstocks only; they do not account for the energy input related to the formation of fossil resources nor the solar energy absorbed during biomass growth.

[3] Based on the associated documentation (EPA, 2009), it is not clear why EPA's results for cellulosic ethanol have negative GHG results. However, their boundaries consider the import and export of agricultural products, which could explain in part the negative GHG balance.

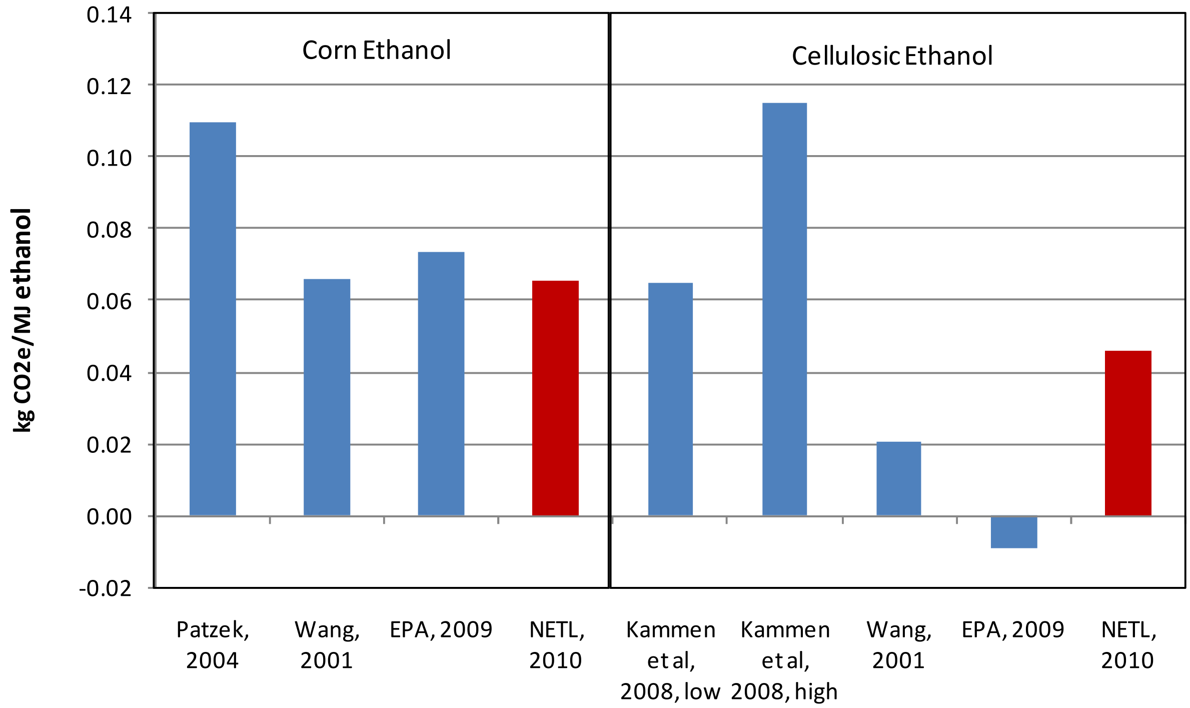

Figure ES-5: Comparison of LC Greenhouse Gas Results for Ethanol

1.0 INTRODUCTION

The United States of America is currently faced with competing strategic objectives related to energy: energy supply security, economic sustainability, and concerns regarding global climate change. The transportation sector is at the crux of this dilemma. High fuel prices directly affect the health of the U.S. economy and economic competitiveness, while roughly two-thirds of U.S. transportation fuels are imported, and fossil-based transportation fuel is responsible for more carbon dioxide (CO_2) emissions than any other sector of the U.S. economy, accounting for 34 percent of total annual CO_2 emissions.

The Department of Energy's (DOE) National Energy Technology Laboratory (NETL) has been evaluating the production of energy in both the renewable and non-renewable sectors for use in energy (heat and power) and liquid transportation fuels. In order to better inform stakeholders of the consequences of energy pathways, NETL is developing a standard method to perform environmental Life Cycle Assessment (LCA) and Life Cycle Cost (LCC) analysis. This report and its supporting documentation are the result of developing a rigorous method for performing LCA and LCC. The analysis of this report focuses on various pathways to ethanol production and the use of ethanol (blended with gasoline) as a transportation fuel.

NETL evaluated published reports on the production of ethanol from a variety of fuel production pathways and performed an independent life cycle assessment (LCA) and life cycle cost (LCC) analysis on a variety of ethanol production and end use pathways. NETL modeled an expanded life cycle (LC) to include not only CO_2 emissions, but also to provide a balanced environmental LC perspective that includes:

- Greenhouse gas (GHG) emissions
- Resource energy consumption
- The release of criteria air pollutants (CAPs) and other air pollutants to the atmosphere
- The release of water pollutants
- The withdrawal and consumption of water from both surface and groundwater supplies
- The type and acreage of the land used
- A parallel LCC analysis

The basis documents used for this study were completed outside of NETL and represent the LC GHG emissions of ethanol pathways and the LCCs of cellulose-to-ethanol pathways. This report details key assumptions related to the environmental and cost modeling of the LCs of ethanol production pathways, and includes a discussion of the LC method employed in the environmental model, the financial parameters and costs of the cost model, the identification of key data sources and limitations, a presentation of the results, and a sensitivity analysis of the results.

For this study, four separate basis documents were used:

- EPA. (2009a). *Draft Regulatory Impact Analysis: Changes to Renewable Fuel Standard Program*. U.S. Environmental Protection Agency, Office of Transportation and Air Quality, Assessment and Standards Division. http://www.epa.gov/otaq/renewablefuels/420d09001.pdf. EPA-420-D-09-001.

- EPA. (2009b). *Federal Register: Regulation of Fuels and Fuel Additives: Changes to Renewable Fuel Standard Program; Proposed Rule.* U.S. Environmental Protection Agency. http://www.epa.gov/otaq/renewablefuels/rfs2_1-5.pdf. 40 CFR Part 80.
- Aden, A., Ruth, M., Ibsen, K., *et al.* (2002). *Lignocellulosic Biomass to Ethanol Process Design and Economic Utilizing Co-Current Dilute Acid Prehydrolysis and Enzymatic Hydrolysis for Corn Stover*. National Renewable Energy Laboratory. NREL/TP-510-32438.
- Phillips, S. D., Aden, A., Jechura, J., *et al.* (2007). *Thermochemical Ethanol via Indirect Gasification and Mixed Alcohol Synthesis of Lignocellulosic Biomass*. National Renewable Energy Laboratory, Golden, CO. NREL/TP-501-41168.

The study has a cradle to grave environmental system boundary as shown in **Figure 1-1**. The economic system boundary, as shown in **Figure 1-2**, is identical to the environmental boundary except no costs are assigned to the ”End Use” of fuel.

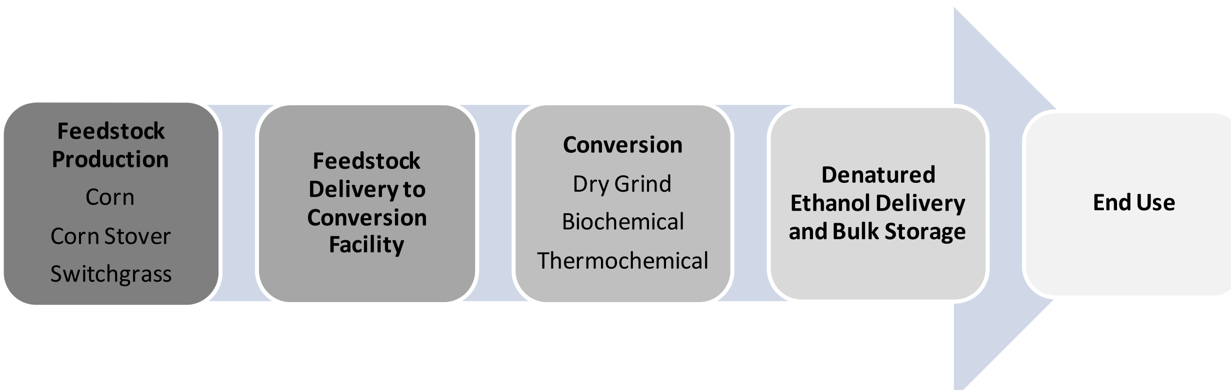

Figure 1-1: Environmental System Boundary

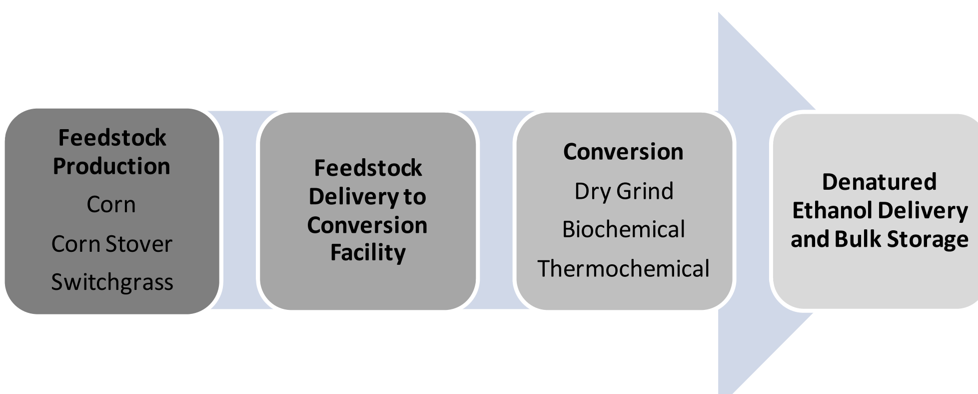

Figure 1-2: Economic System Boundary

The study investigates both current (dry grind) and future (biochemical and thermochemical gasification) conversion scenarios[4].

- The dry grind scenario uses corn kernels as a feedstock. The corn meal is fed to continuous liquefaction and saccharification tanks. Enzymes are added at each step to break the starch molecules into glucose. The glucose is then fermented to ethanol using yeast. From there, the ethanol is separated and purified using distillation and vapor phase molecular sieves respectively. The effluent from the ethanol separation is processed into a high protein animal feed, distiller's Dry Grain with Solubles (DDGS).
- The biochemical conversion process uses either corn stover or switchgrass as a feedstock. The feedstock is mixed with hot water and pretreated with sulfuric acid at high temperature and pressure. The pretreatment step releases the cellulose/hemicellulose/lignin bonds as well as breaks the hemicellulose into monomers, mainly xylose. Following pretreatment, the cellulose is treated with enzymes that break it into glucose monomers. The xylose and glucose (along with minor sugars) are fermented into ethanol. The separation step to purify the ethanol is the same as in the dry grind scenario above. The effluent from the separation is used in a fluidized bed combustion reactor, followed by a turbo-generator to produce the steam and electricity requirements for the process.
- The thermochemical gasification process uses an indirect gasifier to produce a mixture of gases. The mixture is treated with a catalyst to 'clean up' the gas, removing tars and unwanted chemicals to produce a clean syngas (CO and H_2). The syngas is fed over a catalyst to produce ethanol and a mixture of higher alcohols (C_4 and higher). Methanol produced during this process is recycled until it is depleted. The ethanol is separated from the higher alcohols.

[4] Dry grind ethanol plants represent the majority of current U.S. ethanol production. However, the current commercial status of the three ethanol production technologies and how they align with current and future ethanol production in the U.S. are outside the scope of this analysis.

2.0 GOAL AND SCOPE

The analysis presented in this report allows NETL to inform both internal technology managers and the public of potential benefits and drawbacks of ethanol production from corn and lignocellulosic biomass to be used as a transportation fuel. The analysis independently evaluates and compares the environmental and economic LC performance of 18 scenarios, based on three technology pathways, three biomass feedstocks, and two blends of transportation fuel.

The end products of this analysis are E10 and E85, which are two different blending ratios of ethanol and gasoline. E10 is a 10/90 volumetric split between ethanol and gasoline. The annual average composition of E85 is a 74/26 volumetric split between ethanol and gasoline in this analysis, which is a blending ratio that accounts for the higher share of gasoline used for cold-weather blends of E85 (EIA, 2009, p. 113).

In addition to various life cycle paths to ethanol production, this analysis includes a parallel model for the life cycle of gasoline. The gasoline model is based on prior work conducted by NETL (NETL, 2008) which is not reprinted here. To review the details of the gasoline model, please refer to the NETL (2008) document. Details on the gasoline model that are relevant to the present study are provided in the supporting appendix documentation to this report.

This analysis applies uniform scope, boundaries, and modeling methods across a wide array of scenarios. The scope of an LCA includes decisions related to the basis of comparison, system boundaries, and key assumptions. The system boundaries are described in **Section 1.0**. Key assumptions are described in **Section 3.3**. This study examines the GHG, water, CAP, and land issues, as well as a full LCC of the described ethanol production pathways.

3.0 METHODS

The environmental LCA approach uses the International Organization for Standardization (ISO) 14040 “Environmental Management – Life Cycle Assessment – Principles and Framework” (ISO, 2006). This study includes three of the four phases of an LCA as defined by ISO (2006): goal and scope definition, life cycle inventory (LCI), and interpretation (including sensitivity analysis). This study does not include life cycle impact assessment (LCIA).[5]

GaBi 4[6] is a database-driven software tool designed to assist LCA practitioners in documenting, managing, and organizing LCI data. The tool includes a comprehensive impact assessment capability and data interpretation and reporting capabilities. The system works by performing comprehensive balancing (mass and energy) and environmental balancing around an interdependent network of unit processes, a method that is consistent with the ISO standards for LCA (ISO, 2006). GaBi 4 includes a large database of LCI profiles for various energy production methods, material production and assembly, transportation, and other production and construction material that can be used to assist in modeling the LC of each pathway. For example, unit processes contained in the GaBi 4 database are used in this analysis instead of developing original data for processes such as electricity generation, steel production, and aluminum production. Applicable data sets were utilized from the GaBi software for modeling secondary processes. Primary processes, such as ethanol production, were modeled within the GaBi software tool using data available in the basis documents and other sources. Any additional systems modeling conducted outside of these tools are considered a “data source” used to inform the analysis process.

3.1 Metrics

The focus of this assessment is to develop LC profiles on both the environmental and cost levels for a set of biomass to ethanol pathways. The environmental study focuses on the global warming potential and criteria air pollutants from the processes, as well as water use and discharge issues. The boundary of the environmental LC is from cradle to vehicle exhaust.

Emissions of GHGs to the atmosphere are inventoried on both a mass (kg) basis and in terms of the 100-year global warming potential (GWP) of each gas as determined by the 2007 International Panel on Climate Change (IPCC) (IPCC, 2007). **Table 3-1** lists the primary GHGs and their corresponding GWP reported in mass of CO_2 equivalent (CO_2e). Other GHGs, such as chlorofluorocarbons and sulfur hexafluoride, are not included in this analysis because they are negligible in comparison to CO_2, methane, and nitrous oxide.

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5 Impact assessment is the process of understanding and evaluating the magnitude and significance of the potential environmental impacts of a product system (ISO 14040). Technically, calculating the global warming potential (GWP) from GHG contributions uses a widely accepted impact assessment method. However, inclusion of only the GWP calculation as part of this study is considered insufficient by the authors to justify the statement that a comprehensive impact assessment will be conducted.

6 GaBi 4, developed by the University of Stuttgart (IKP) and PE Europe of Germany, was used to conduct the environmental LCI using a process-based approach.

Table 3-1: Primary Greenhouse Gas and Corresponding GWP Included in Study Boundary (IPCC, 2007)

Emissions to Air	GWP (CO_2e)
Carbon Dioxide	1
Methane	25
Nitrous Oxide	298

Table 3-2 lists the six EPA-regulated CAPs, which are inventoried in terms of mass (kg) emitted to the atmosphere. Other air pollutant species of interest include mercury, ammonia (NH_3), hydrogen chloride (HCl), hydrogen fluoride (HF), non-methane volatile organic compounds (VOCs), and other heavy metals determined to be more than 1 percent of unit process emissions on a mass basis).

Table 3-2: Criteria Air Pollutants Included in Study Boundary (EPA, 2008)

Emissions to Air	Comment
Carbon Monoxide	--
Nitrogen Dioxide/Nitrogen Oxides	Includes all forms of nitrogen oxides.
Sulfur Oxides	Includes sulfur dioxide (SO_2), and other forms of sulfur oxides. In the results of this analysis, SO_2 accounts for 99 percent of the total SO_x inventory.
Volatile Organic Compounds	VOCs are reported as non-methane VOCs to avoid double counting with reported methane emissions.
Particulate Matter	Includes all forms of particulate matter (PM): PM_{10}, $PM_{2.5}$, & unspecified mean aerodynamic diameter. PM_{10} inventory results include $PM_{2.5}$ results, and thus to avoid double counting these two inventory species are not added.
Lead	--

The focus on the cost analysis is to compare the cost at each stage of the LC using peer reviewed literature and industry data where available. Unlike the environmental LC, the cost boundary is from the field to the pump. In comparing each scenario, a consistent set of economic/financial parameters were used. These parameters are shown in **Table 3-3**.

3.2 Modeling Approach

It is critical to name a functional unit to satisfy ISO 14040 & 14044 criteria for LCA. The functional unit quantifies the service that is delivered by a product or system and provides a basis for comparison between two or more cases of an LCA. In addition to providing a fair basis for comparison, a well-selected functional unit also provides an effective basis for communicating the results of an LCA. The functional unit of this study is the quantity of fuel that is necessary to produce one megajoule (MJ) lower heating value (LHV) of combustion energy to move a 2012 model passenger car with a conventional internal combustion engine (EPA, 2008). All results of this analysis are expressed on this basis.

Table 3-3: Financial Parameters used in LCC

Property	Value	Units
Reference Year Dollars	2008	Year
Assumed Start-Up Year	2012	Year
Real After-Tax Discount Rate	10.0	Percent
After-Tax Nominal Discount Rate	12.1	Percent
Assumed Study Period	30	Years
MACRS Depreciation Schedule Length	Variable	Years
Inflation Rate	1.9	Percent
State Taxes	6.0	Percent
Federal Taxes	34.0	Percent
Total Tax Rate	38.0	Percent

An attributional LCI approach requires the identification of the significant processes in the LC of each pathway, a mass and energy balance around each unit process, and the linkage of all unit processes in each pathway according to the functional unit (the basis of comparison) of the LCA. This analysis provides a life cycle comparison of three tiers of technology, three types of biomass feedstocks, and two fuel-blending compositions, for a total of 18 distinct pathways. **Figure 3-1** summarizes the pathways to E10 and E85 production.

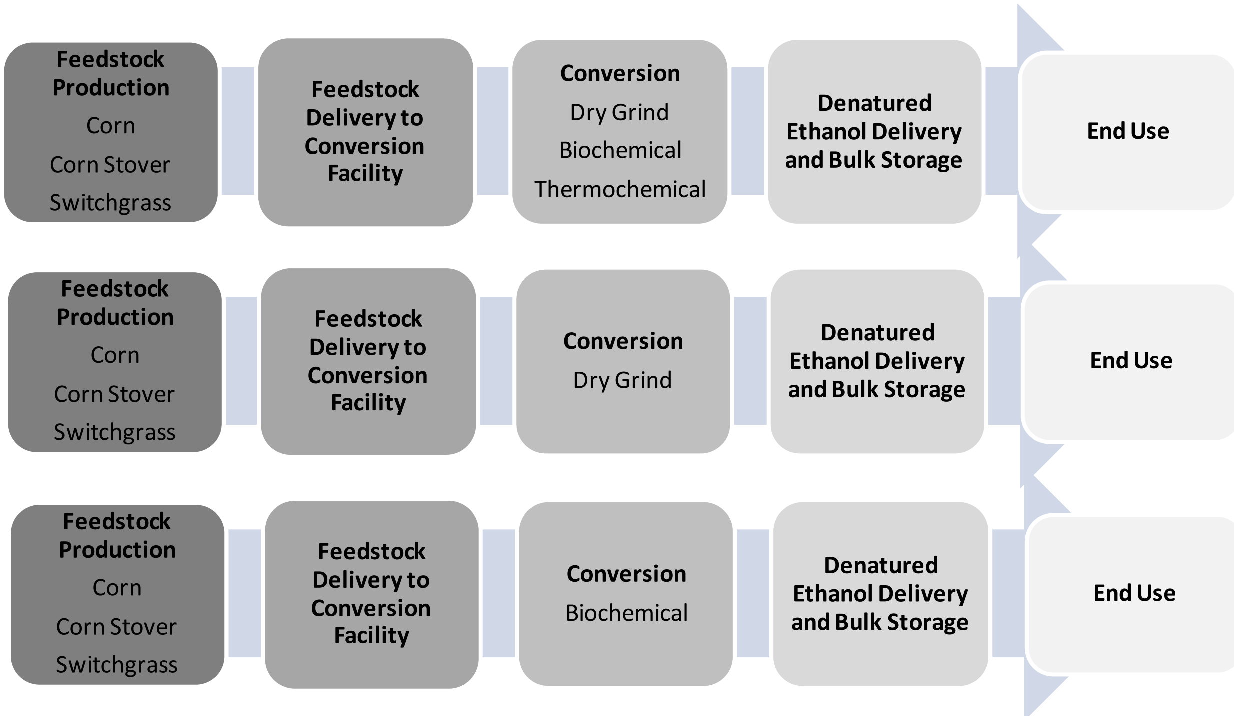

Figure 3-1: Dry Grind, Biochemical, and Thermochemical Pathways to E10 and E85 Production

System expansion has been used to avoid co-product allocation at the ethanol production facility (LC Stage #3). This method expands the system boundary to include the production of co-products by other means, assigning a co-product credit (or offset) for the production of the co-product based on the production of a similar substance. In this analysis, system expansion is used for dried distiller's grain with solubles (DDGS), corn oil, electricity and mixed alcohols.

When modeling system expansion, a profile of the displaced product is necessary. In some cases, and with common goods, these profiles are available in the GaBi model database. However, those profiles are often not transparent and may include or omit key aspects of the system boundary. Therefore, it is often preferred to create an LC profile, using either data from previous LCA studies or other high quality data sources. **Table 3-4** outlines the LC profiles used by this study for modeling the displacement of a co-product.

In general, a consequence of system expansion is that it requires making assumptions about secondary products that are not necessarily related to the functional unit of an LCA. These necessary assumptions introduce uncertainty to the analysis. In the present analysis, one noteworthy consequence of using system expansion to manage co-products is the relationship between displacement and the uptake of biogenic CO_2. System expansion establishes a relationship between the co-products of the dry grind ethanol plant (LC Stage #3) and the amount of CO_2 uptake that is calculated for the growth of corn (LC Stage #1). Specifically, when co-products of the dry grind ethanol plant are assumed to displace biomass materials used for non-ethanol products, they are precluding resource consumption and emissions that would have been generated by the displaced materials, but are also precluding the uptake of biogenic CO_2 that would have been accomplished by the displaced materials. As a result, ethanol dry grind co-products prevent the uptake of CO_2 by other biomass systems, and the net biogenic CO_2 of an advanced ethanol dry grind (which has DDGS and corn oil co-products) is higher than the net biogenic CO_2 of a dry grind (which co-produces only DDGS).

Table 3-4: Data Sources for Ethanol Co-Products

Co-Product	Displacement Life Cycle	Data Source
DDGS	Corn-based animal feed	Present study[7]
Corn Oil	Oil-to-biodiesel (corn oil extracted after fermentation is a suitable replacement for soybean oil feedstock to biodiesel)	Sheehan, 1998
Mixed Alcohol	Current dry grind ethanol (base case)	Present study[8]
Electricity	Electricity generated in the U.S. Midwest	NETL electricity model based on 2005 resource profile in eGRID (EPA, 2007)

In addition to the co-products of the ethanol plant, this study includes co-product streams for corn production. LC Stage #1 includes the co-production of corn grain and corn stover, both of which are biomass feedstocks used by the cases of this study. The management of co-products using system expansion with displacement (described above) is not feasible for assigning environmental burdens between corn grain and corn stover because there is no strong argument that the use of corn stover displaces another cellulosic feedstock. Thus, for the cellulosic pathways (the biochemical and thermochemical technologies), co-product allocation is used to assign burdens between corn grain and corn stover using the relative calorific values of grain and stover as the default basis for co-product allocation (resulting in a 59/41 allocation split between stover and grain). The dry grind pathways, on the other hand, assume that corn stover is not an established feedstock for the production of fuels or other materials, and is not collected from the field after harvesting the corn grain. Thus, for the dry grind pathways, co-product allocation between corn grain and corn stover is not necessary.

3.3 Modeling Assumptions

This study assumes a plant location in the Midwest, U.S. with a temporal boundary that includes a 3 year construction period from 2009 through the end of 2011, and a 30 year operating period, from 2012 to 2042. The environmental boundary is from cradle-to-grave, beginning with raw material acquisition and ending with the combustion of the blended fuel (E10 or E85) in a passenger vehicle. However, it should be noted that while E10 is a 10/90 volumetric split between ethanol and gasoline, E85 is modeled as a 74/26 volumetric split between ethanol and gasoline in this analysis, due to seasonal and other variations in E85 blends (EIA, 2009, p. 113).

[7] DDGS displaces corn used for animal feed; the data for corn production and delivery, as modeled by this analysis, is used to model the displacement caused by DDGS.

[8] Mixed alcohols displace ethanol used as a fuel additive; the data for dry grind ethanol production is used to model the displacement caused by mixed alcohols.

The cost boundary is from cradle-to-tank, beginning with raw material acquisition and ending with delivery of blended fuel (E10 or E85) to a passenger vehicle. Cost results are expressed in terms of the RSP of E10 and E85, normalized to an equivalent energy of gasoline (a gallon of gasoline has 1.03 and 1.35 times more energy than a gallon of E10 and E85, respectively). The following section provides a detailed explanation of assumptions for each stage in the LC for both environmental and cost assessments.

3.3.1 LC Stage #1: Raw Material Acquisition

The boundary of LC Stage #1 begins with land preparation for growth of biomass. The boundary ends with the loading of biomass feedstock onto trucks for delivery to the ethanol production facility. This analysis focuses on three biomass feedstocks: corn grain, corn stover, and switchgrass. A detailed discussion on the data used for modeling these three feedstocks is provided in the supporting appendix documentation. Key assumptions for LC Stage #1 are summarized below.

This analysis investigates only conventional tilling practices, ignoring no-till practices and associated effects. Additionally, this study investigates only corn-corn rotation practices; the data are not representative of corn-soybean rotations. It is understood that alternative tilling and crop rotation practices can have significant effects on the LC Stage #1 use of nitrogen, carbon storage and runoff. Future studies should address tilling and crop rotation issues either as sensitivities or direct comparisons.

The dry grind scenarios assume that corn grain is the only useful product from the corn plant. For these scenarios the corn stover remains on the field and provides nutrient replacement and erosion prevention. Thus, for the dry grind scenarios, all the burdens of land preparation, cultivation, and harvesting are assigned to the corn grain – co-product allocation is not necessary for apportioning the environmental burdens of land preparation, cultivation, and harvesting between corn grain and corn stover.

The biochemical and thermochemical scenarios include the production of ethanol from corn stover. While these scenarios do not use corn grain as a feedstock, they assume that corn grain is a viable feedstock for other products. Thus, the biochemical and thermochemical scenarios require co-product allocation between corn grain and corn stover. The percentage of resources and emissions allocated to each product (corn grain and corn stover) is determined by their relative calorific values (in MJ/kg) factored by their relative yields (in kg/acre). Based on the relative yields and calorific values of corn grain and corn stover, the burdens incurred by corn production are allocated to corn grain and corn stover using a 41/59 split[9].

When corn stover is collected from a corn field, it is necessary to apply fertilizer to the field in order to replace the nutrients that are removed with the corn stover. (This fertilizer replacement is *in addition to* the fertilizer used during the cultivation of the corn plant.) The collection of corn stover and subsequent fertilizer replacement are two activities that occur at the corn field

[9] The yield of corn stover is 1.29 times greater than the yield of corn grain (3,860 kg/acre vs 2,980 kg/acre), and the calorific value of corn stover is 1.10 times greater than corn grain (17.0 MJ/kg vs 15.5 MJ/kg) (Shapouri *et al.*, 2002; Pimentel and Patzek, 2005; Murphy, 2009). Based on these yields and calorific values, corn stover is assigned a higher share of the environmental burdens that occur in LC Stage #1 (Raw Material Acquisition).

that are assigned solely to corn stover production. Thus, co-product allocation is not necessary in apportioning corn stover collection and fertilizer replacement because they are solely attributable to corn stover. **Figure 3-2** shows the individual and shared boundaries.

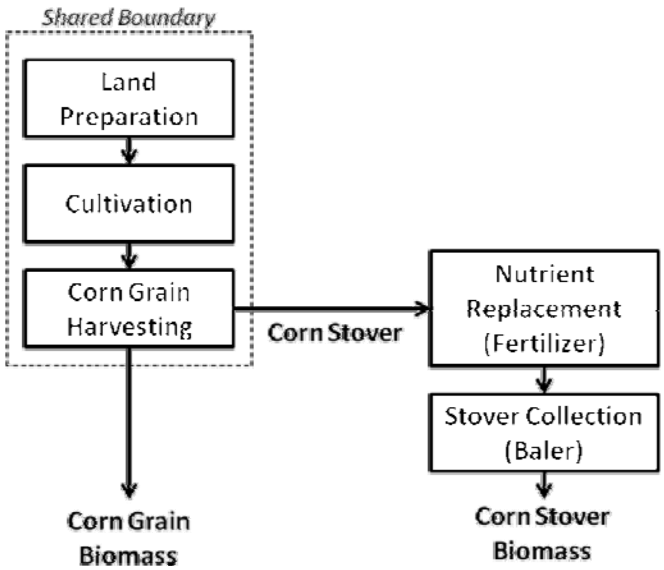

Figure 3-2: Stover and Corn Grain Shared Boundary and Allocation

3.3.2 LC Stage #2: Raw Material Transport

LC Stage #2 includes transport of all raw materials to the fuel production facility (i.e., biomass to ethanol plants and crude oil to petroleum refineries). The boundary ends with unloading of the feedstock material at the energy conversion facility.

Trucks are used to move biomass feedstocks from growing sites to ethanol plants. The transportation distances between growing sites and ethanol plants are 42, 46, and 61 miles, respectively, for corn grain, corn stover, and switchgrass.

The above transportation distances are based on a feedstock collection radius that is a function of the feed rate to each ethanol plant, the biomass yield per acre, and energy crop intensity. The feedstock input to each ethanol plant is defined by the data for each technology (EPA, 2009; Aden *et a.l,* 2002; Phillips *et al.*, 2007). The biomass yield is accounted for in NETL's unit processes for biomass production. The energy crop intensity is based on the assumption that half of the available cropland in Iowa and Nebraska is used for energy crops. The transport path is assumed to occur along hypothetical roadways oriented north to south, and east to west. Therefore, to arrive at a farm located at radius "r" and angle "θ," the truck would travel distance "d" as calculated by **Equation 1**.

(Equation 1)

This analysis assumes that the fuel efficiency of trucks used for biomass transport does not change significantly when making an empty return trip. An empty truck has a higher fuel efficiency than a loaded truck, but no data are available that allow such an adjustment to the fuel efficiency data for on-road transport[10].

The LCC model does not account for any costs in LC Stage #2. All costs related to the transport of biomass are assumed to be accounted for in the delivered cost of biomass at the entry gate of the ethanol plant in LC Stage #3.

3.3.3 LC Stage #3: Fuel Production Facility

The boundary of LC Stage #3 begins at the entrance of the fuel production facility and ends with denatured ethanol (a mixture of 95% ethanol and 5% gasoline, known as E95) ready for transport to a bulk loading terminal[11]. For pathways with carbon capture and sequestration (CCS), this LC stage includes all CCS equipment and operations, beginning with capture of CO_2 at the energy conversion facility and ending with sequestration in an underground geologic structure. The capacity factor for all conversion facilities of this analysis is 96%.

3.3.3.1 LC Stage #3 Environmental Assumptions

The dry grind technology for the conversion of corn to ethanol is based on a model of a 40 million gallons per year (MGY) facility that is representative of current commercial ethanol plants (USDA, 2008). However, to establish consistent production rates among all ethanol plants of this analysis, the operational flows were scaled to represent a 60 MGY facility. This adaptation does not account for any efficiencies of scale for the operations of the ethanol plant, but does affect the required collection radius of corn feedstock.

This analysis includes a scenario in which the dry grind process is augmented with a post-fermentation corn oil extraction unit. The energy requirements and material flow rates of the corn oil extraction unit are modeled based on vendor specifications (Greenshift, 2010). The resulting corn oil is not suitable as a feedstock for food production, but is an adequate feedstock for biodiesel production.

This analysis includes a scenario in which the dry grind process with corn oil extraction is further augmented by a CO_2 recovery system that sends CO_2 to an underground sequestration site. CO_2 exits the ethanol plant as a relatively pure stream and does not require a separation process; specifically, it is assumed that a water knockout step is not necessary. The operational flows of the CO_2 recovery system are based on the energy required to compress CO_2 from atmospheric pressure to a required pipeline pressure of 2,220 pounds per square inch (psi).

The CO_2 pipeline modeled in this analysis runs a distance of 100 miles from the ethanol plant to a sequestration site, does not require further compression after leaving the ethanol plant, and has a loss rate of 0.0165% of total CO_2 transported (Kinder Morgan, 2009). One percent of the CO_2 that is injected at the sequestration site is assumed to be unintentionally vented over a period of

[10] While this data limitation results in a possible overstatement of truck energy consumption, the results of this analysis are not sensitive to changes in raw material transportation distances.

[11] Pure ethanol must be mixed with an additive such as gasoline to make it unfit for human consumption. The reference documents used by this analysis (Aden *et al.*, 2002; EPA, 2009) assume that ethanol is denatured with gasoline up to 5 percent by volume.

100 years. Other activities related to the CO_2 sequestration site (such as operating energy or water that is forced out of saline aquifers) are not included in this analysis.

The biochemical conversion of cellulose to ethanol is based on a 69.3 MGY ethanol facility, operating 350 days per year, and that is representative of market competitive technology at the time of this writing, but has not been commercialized (Aden *et al.*, 2002). The data for the biochemical conversion of cellulose to ethanol is representative of a technology that uses fluidized bed combustion (FBC) to recover energy from fermentation byproducts (Aden *et al.*, 2002).

A separate analysis in which FBC is replaced by gasification was performed. No data are available for the operation of a gasifier at a biochemical ethanol plant, and thus surrogate data (Phillips *et al.,* 2007) was used. The surrogate data is representative of a gasifier with a higher throughput than necessary for energy recovery from the waste of a biochemical ethanol plant. Additionally, the surrogate data are representative of a feedstock (wood chips) that has a lower moisture content than the waste biomass of a biochemical ethanol plant. The use of surrogate data for the gasification of waste biomass from a biochemical ethanol plant is a data limitation of this analysis.

The thermochemical conversion of cellulose to ethanol is based on a 62 MGY ethanol facility that is representative of market competitive technology, but has not been commercialized (Phillips *et al.*, 2007).

The data available for cellulosic ethanol production technologies (Aden *et al.*, 2002; Phillips *et al.*, 2008) are representative of material balances of ethanol produced from corn stover. Adequate data are not available for the production of ethanol from switchgrass. The data for the conversion of corn stover to ethanol were adapted to represent ethanol produced from switchgrass by scaling it by the relative sugars composition of corn stover and switchgrass.

System expansion is used to manage the co-products of ethanol plants. DDGS (dried distillers grain with solubles) is a co-product of all dry grind ethanol plants, corn oil is a co-product of dry-grind ethanol plants that have corn oil extraction units, electricity is a co-product of biochemical ethanol plants, and mixed alcohols are co-products of thermochemical ethanol plants. DDGS is assumed to displace conventional nutritional sources for animal feed; soy and corn grains are conventional nutritional sources for animal feed, but this analysis assumes that animal feed is comprised entirely of corn grain. Corn oil is assumed to displace soybean feedstock to biodiesel. Electricity is assumed to displace electricity on the Midwest Reliability Organization West (MROW) grid. Finally, mixed alcohols are assumed to displace gasoline additives.

The "current" dry grind ethanol plant is assumed to be an existing facility and thus this analysis does not model construction. However, the dry grind ethanol plants that employ corn oil extraction and/or CO_2 recovery are assumed to be new construction. The material requirements for a "typical" dry grind ethanol plant are available in the literature (Hill *et al.*, 2006). This analysis assumes that the construction requirements of a dry grind with corn oil extraction are 5 percent higher than a typical dry grind facility[12]. Construction requirements of a dry grind with

[12] No data are available for the construction requirements of a dry grind ethanol plant with corn oil extraction. This analysis assumes that a corn oil extraction system adds five percent to the total construction requirements of the

corn oil extraction and CO_2 recovery are a function of the cost per mile of pipeline and the CO_2 distance traveled.

The construction requirements for cellulosic ethanol plants were estimated from the capital costs of the plants as provided in the documentation on cellulosic technologies (Aden *et al.*, 2002; Phillips *et al.*, 2008). The weights of carbon steel and stainless steel were estimated using cost factors for the design of high-pressure vessels. The concrete requirements were estimated from the total area required for the process equipment and an assumed concrete thickness and density.

3.3.3.2 LC Stage #3 Cost Assumptions

The LCC model accounts for the capital and operating costs of ethanol plants in LC Stage #3. The following activities are included in LC Stage #3 of the LCC model.

Data on the operating costs of dry grind ethanol plants are provided by USDA's dry grind model (USDA, 2008) and operating costs for cellulosic technologies are provided by studies conducted by NREL (Aden *et al.*, 2002; Phillips *et al.*, 2007).

Data on the capital costs of ethanol plants are available in the same literature used for operating costs (USDA, 2008; Aden *et al.*, 2002; Phillips *et al.*, 2007). Capital costs are not modeled for conventional dry grind (which have no corn oil extraction processes or CO_2 recovery) because they are assumed to be existing plants that do not require new capital investment. According to the basis documents for this analysis, the cost of the gasifier in the gasification system is $12-million lower than the FBC.

The feedstock cost for corn is assumed to be constant at a price of $3.50/bushel ($125/ton). Estimations for the cost of corn stover to the entrance of the pretreatment reactor have been rigorously developed by Idaho National Laboratory (INL, 2009). The INL study does not include a grower payment to their calculated feedstock cost. INL reports a feedstock cost close to $72/ton in 2011, with technological advances bringing the cost down to $30/ton by 2017. In assuming a grower payment, it is important to realize that the first plants will be getting the lowest cost feedstocks with minimal grower payments, and as the industry matures and demand increases, the quality of biomass, and more importantly, land, will rise as will the premium payment to the grower. Combining the two for a delivered feedstock cost, this analysis assumes that the benefits with process improvements are offset by the increase in grower payment as the industry matures. Therefore, the first payment to the growers is $15/ton, bringing the total feedstock cost for stover to $87/ton. The cost of switchgrass is based on the NETL Coal-Biomass to Liquids Baseline Study (NETL, 2009d) at $76.70/ton.

Key operating costs and their data sources are summarized in **Table 3-5**. The unit costs are reported as shown in the data source, and thus the dollar year is shown with each cost. The LCC model adjusts these costs according to the study period.

facility. This approximation is based on professional judgment. The final results of this analysis are not sensitive to changes in plant construction requirements.

Table 3-5: Key Operating Costs

Utilities	Unit Cost	Data Source
Natural gas	$7.71/MMBtu (2007 dollars)	EIA, 2009
Electricity	$0.065/kWh (2007 dollars)	EIA, 2009
Coproducts	**Unit Cost**	**Data Source**
DDGS	$0.137/kg (2008 dollars)	USDA, 2008
Corn oil	$0.353/kg	USDA, 2008
Electricity	$0.065/kWh (2007 dollars)	EIA, 2009
Higher alcohols	$1.15/gal (2005 dollars)	Phillips, 2007

Adequate data are not available for the capital costs of CO_2 recovery systems or corn oil extraction units, which are employed by two of the plant technologies of this analysis. This data gap is addressed by assuming that the capital costs of an ethanol plant with corn oil extraction are 5 percent higher than a conventional dry grind plant and the capital costs an ethanol plant with corn oil extraction. For the case that adds CO_2 recovery, cost are based on the cost of the pipeline and distance traveled. The estimated capital costs of ethanol plants are shown in **Table 3-6.**

Table 3-6: Estimated Capital Costs

Technology	Total Capital Cost (Million $ 2008)	Data Source
Dry Grind Ethanol Plant w/ Corn Oil Extraction	$94.6	USDA, 2008
Dry Grind Ethanol Plant w/ Corn Oil Extraction and CO_2 Recovery	$99.1	USDA, 2008
Biochemical Ethanol Plant	$133	Aden *et al.,* 2002
Thermochemical Ethanol Plant	$146	Phillips *et al.*, 2007

The CO_2 pipeline, which is used by only one plant technology in this analysis, is designed so that the compression of CO_2 at the ethanol plant can move CO_2 the total distance to the sequestration site without additional compression boosting stations along the pipeline. Thus, the operating costs of the CO_2 pipeline are accounted for in the preceding steps at the ethanol plant. Limited data are available for the capital costs of CO_2 pipelines, however, studies have shown that pipeline costs can be anywhere from $200k to $1M per mile (Nyman *et al.,* 2004). Therefore, this analysis uses a pipeline cost factor of $600,000 per mile.

3.3.4 LC Stage #4: Product Transport

LC Stage #4 includes the transport of liquid fuels to a vehicle refueling station, which includes the mixing of E95 and gasoline at an intermediate bulk loading terminal. The boundary begins at the exit of the fuel production facility (ethanol plant) and ends with the delivery of blended fuel (E10 and E85) to the vehicle refueling station.

3.3.4.1 LC Stage #4 Environmental Assumptions

Ethanol is transported from the ethanol plant to a bulk loading terminal by a 100 mile pipeline. This assumption is not representative of the current ethanol industry, but represents a well-established ethanol industry with enough capacity to justify the construction of an ethanol pipeline.

The bulk loading terminal is assumed to be an existing facility and thus the construction of gasoline storage tanks and other systems are not accounted for in this analysis. However, the construction of new storage tanks for ethanol is included in this analysis because fixed-roof storage tanks, which are not a part of the existing bulk loading terminal, are required to prevent the contamination of ethanol with water.

Ethanol and gasoline are mixed when loaded onto tanker trucks (splash blending). E10 and E85 blending ratios are included in this analysis. As discussed previously, E10 is a 10/90 volumetric split between ethanol and gasoline, and E85 is a 74/26 volumetric split between ethanol and gasoline.

A bulk loading terminal requires electricity for pumps and other equipment necessary for the distribution of liquid fuels. No data are available for the operations of a bulk loading terminal, and thus the electricity requirements of a retail refueling facility (NETL, 2008) are used as a surrogate for the energy consumed by a bulk loading terminal. The electricity required for these operations is supplied by the MROW grid.

Tanker trucks with a 9,500 gallon capacity are used to transport blended fuels (E10 and E85) from the bulk loading terminal to a retail refueling station, a one-way distance of 35 miles, for a total round-trip distance of 70 miles. This analysis assumes that the tanker trucks are dedicated to bulk loading terminal operations, making it unnecessary to allocate truck use among multiple services. The cab of a tanker truck is assumed to have a 5-year life and the trailer of a tanker truck is assumed to have a 10-year life.

This analysis assumes that the fuel efficiency of trucks used for the transport of blended fuels does not change significantly when making an empty return trip. An empty truck has a higher fuel efficiency than a loaded truck, but no data are available that allow such an adjustment to our fuel efficiency data on road transport.

The vehicle refueling station is defined as fuel storage tanks, pumps, and dispensing stations. The electricity used to transfer fuel from underground storage tanks to vehicles is provided by the NETL Petroleum Baseline (NETL, 2008). This electricity is assumed to be supplied by the MROW grid.

The construction of a vehicle refueling station is not included in this analysis because it is assumed to be an existing facility with a useful life that encompasses many products in addition to E10 and E85 fuels.

3.3.4.2 LC Stage #4 Cost Assumptions

The LCC model accounts for the liquid fuel distribution requirements of LC Stage #4, beginning with the acquisition of the two liquid fuel types (E95 and gasoline) and ending with the delivery of blended fuels (E10 and E95) to a passenger vehicle. The following processes are included in LC Stage #4 of the LCC model.

Operating costs include the electricity requirements for pumps and are based on an energy factor of 0.025 kWh/ton-mile of liquid fuel transport (Oregon DEQ, 2004; NETL, 2008) and an industrial electricity cost of $0.065/kWh (2008 dollars) (EIA, 2009). The capital costs of ethanol pipelines are based on cost equations that approximate the material, labor, right-of-way, and miscellaneous costs of pipeline construction (McCoy, 2008); using these equations, the 12-inch diameter, 100 mile ethanol pipeline of this analysis has total capital costs of $44.6 million (2008 dollars).

The operating costs of bulk storage terminals account for the cost of electricity used for pumping liquid fuels and the cost of gasoline purchased for E10 and E85 blending. Labor costs at the bulk loading terminal are not accounted for in this analysis. The LCC model assumes that the cost of gasoline purchased by the bulk loading terminal is $2.15/gallon (2008 dollars) (USDA, 2008). No data are available for the operations of a bulk loading terminal, and thus the electricity requirements of a retail refueling facility (which is 0.00125 kWh/gallon and includes the pumping of liquid fuels from storage tanks through metering operations) (NETL, 2008) are used as a surrogate for the energy consumed by a bulk loading terminal; the cost of industrial electricity is of $0.065/kWh (2008 dollars) (EIA, 2009).

The operating costs (fuel and labor costs only) of tanker trucks are apportioned per unit of liquid fuel transported based on the following details: the fuel economy of tanker trucks is 6 miles/gallon, the cost of diesel is $2.98/gallon (EIA, 2009), trucks are on the road eight hours per day, the volume of liquid fuel held by a tanker is 9,500 gallons, and truck drivers are paid an hourly wage of $18.06 (2009 dollars) (BLS, 2009). The capital cost for a truck (excluding the trailer) is $94,000 (2009 dollars) (Truckpaper.com, 2009).

The LCC model does not account for operating costs of tanker trailers because all operating costs for the road transport of liquid fuel is attributed to the truck, not the trailer. A tanker trailer holds 9,500 gallons of liquid fuel and has a capital cost of $83,800 (2009 dollars) (Truckpaper.com, 2009).

The LCC model does not account for capital costs of vehicle refueling stations for the use of E10 and E85 because they are assumed to be existing facilities and do not require new capital investment . The operating costs of vehicle refueling stations are the electricity requirements and electricity costs of pumping operations. The energy factor for dispensing liquid fuel at a refueling station is 0.00125 kWh/gallon (NETL, 2008) and the cost of commercial electricity is of $0.103/kWh (2008 dollars) (EIA, 2009).

3.3.5 LC Stage #5: Product Use (Fuel Combustion)

The boundary of LC Stage #5 includes operational emissions from the combustion of E10 and E85 fuels and the environmental burdens from the construction of passenger vehicles.

Fuel combustion emissions from passenger vehicles are estimated using emission factors from EPA's Motor Vehicle Emissions Simulator (MOVES) model (EPA, 2008) and data from a 2008 analysis of the differences between gasoline and ethanol combustion (Chester, 2008).

The fuel efficiency of a passenger vehicle will change during the period of this study. However, since the functional unit normalizes the results of the analysis to 1 megajoule (MJ) of fuel, the fuel efficiency of the vehicle does not affect the results related to vehicle operation.

Routine maintenance of passenger vehicles is not included in this analysis.

This analysis assumes that passenger vehicles that consume E10 have the same weights and materials of construction as passenger vehicles that consume E85. The weights of passenger vehicles are assumed to be constant over the study period.

The LCC model does not account for any costs in LC Stage #5. The boundaries of the LCC model are from cradle-to-tank, which exclude the capital and operating costs of passenger vehicles.

4.0 RESULTS

The following sections discuss the results of the environmental and cost modeling in detail through each stage of the LC process.

4.1 Life Cycle Environmental Inventory

The comprehensive LC environmental inventories for each pathway are normalized in terms of the reference flow: 1 MJ of combusted ethanol blended fuel. The following discussion compares the results of the fuel production pathways on this basis. A detailed comparison of the results from this study compared to previous ethanol LCAs is in the appendices.

This analysis examines E10 (a 10/90 volumetric split between ethanol and gasoline) and E85 (a 74/26 volumetric split between ethanol and gasoline). When these fuel blends are combusted, only the portion of the CO_2 attributable to the fossil carbon is tracked as a GHG emission. The E85 pathways absorb more biogenic CO_2 during LC Stage #1 (biomass growth) than the E10 pathways, and thus have lower fossil CO_2 emissions than the E10 pathways. When E85 is combusted, approximately 65 percent of the total CO_2 emissions are biogenic; when E10 is combusted, approximately 7 percent of the CO_2 emissions are biogenic. The biogenic portion of carbon in the ethanol blend is carbon neutral, and is thus not included in the total emission of CO_2 equivalents in LC Stage #5.

The weight of GHG emissions (expressed as CO_2e) per unit of energy product for the E10 and E85 of the ethanol pathways are shown in **Figure 4-1** and **Figure 4-2**, respectively. These figures show biogenic CO_2 as either an uptake or an emission. The uptake of biogenic CO_2 occurs during the growth of biomass and is depicted by the bar to the left of the vertical axis. The emission of biogenic CO_2, which is shown on the far right side of the figures, is from the vent streams of ethanol facilities (LC Stage #3) and the combustion of ethanol fuel (LC Stage #5).

A key feature of **Figure 4-1** and **Figure 4-2** is the narrow black bar within each data series, which marks the net GHG emissions for an ethanol pathway. The net GHG emissions are calculated by subtracting the absolute value of the CO_2 flows to the left of the vertical axis from the fossil- and biogenic- GHG flows shown to the right of the vertical axis. In some cases, the value for net GHG emissions is comparable to the total fossil GHG emissions. This happens when the uptake of CO_2 during the growth of biomass (raw material acquisition) is offset by an equal amount of biogenic CO_2 emissions during ethanol production and combustion.

The fossil CO_2 equivalent emissions of the E10 and E85 pathways are shown in **Figure 4-3** and **Figure 4-4** respectively. Unlike **Figure 4-1** and **Figure 4-2**, which show the weight of net fossil CO_2 emissions alongside the uptake and release of biogenic CO_2, the purpose of **Figure 4-3** and **Figure 4-4** is to focus on the fossil fuel intensity of each LC stage as well as to show displacement of fossil CO_2 due to the cogenerated electricity of the biochemical ethanol facilities. The narrow black bar within each of the four E85 pathways with cogeneration represents the net fossil CO_2 of the associated pathway, taking into account the displaced fossil CO_2 equivalent emissions shown to the left of the vertical axis.

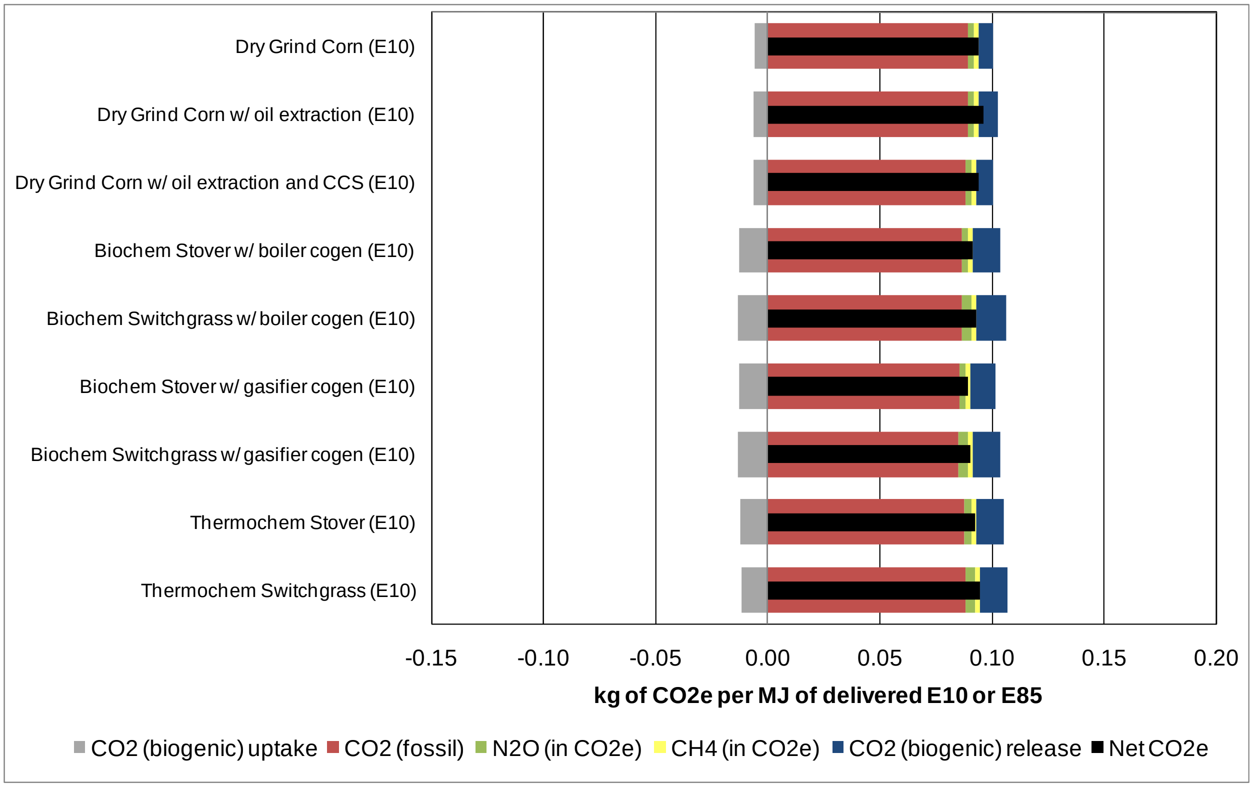

Figure 4-1: Biogenic and Fossil Carbon Dioxide Equivalents for E10 Pathways

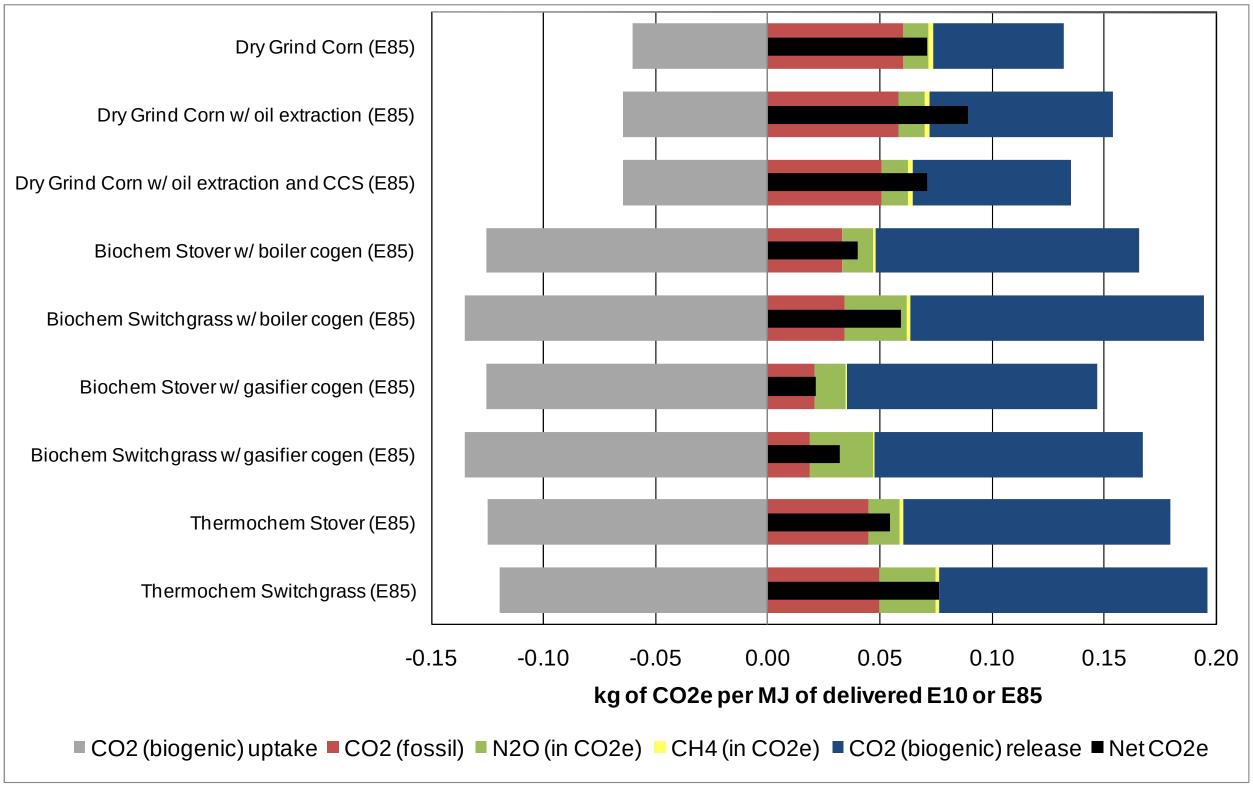

Figure 4-2: Biogenic and Fossil Carbon Dioxide Equivalents for E85 Pathways

Fossil CO_2 emissions are attributable to the combustion of fossil fuels used for the acquisition of biomass and petroleum feedstocks (LC Stage #1 (LC#1)), the combustion of diesel used for the transportation of feedstocks to a fuel production facility (LC Stage #2 (LC#2)), the combustion of purchased fuels at the fuel production facility (LC Stage #3 (LC#3)), the combustion of diesel and indirect emissions from electricity generation used in the distribution of liquid fuels (LC Stage #4 (LC#4)), and the combustion of the delivered fuel in the vehicle (LC Stage #5 (LC#5)).

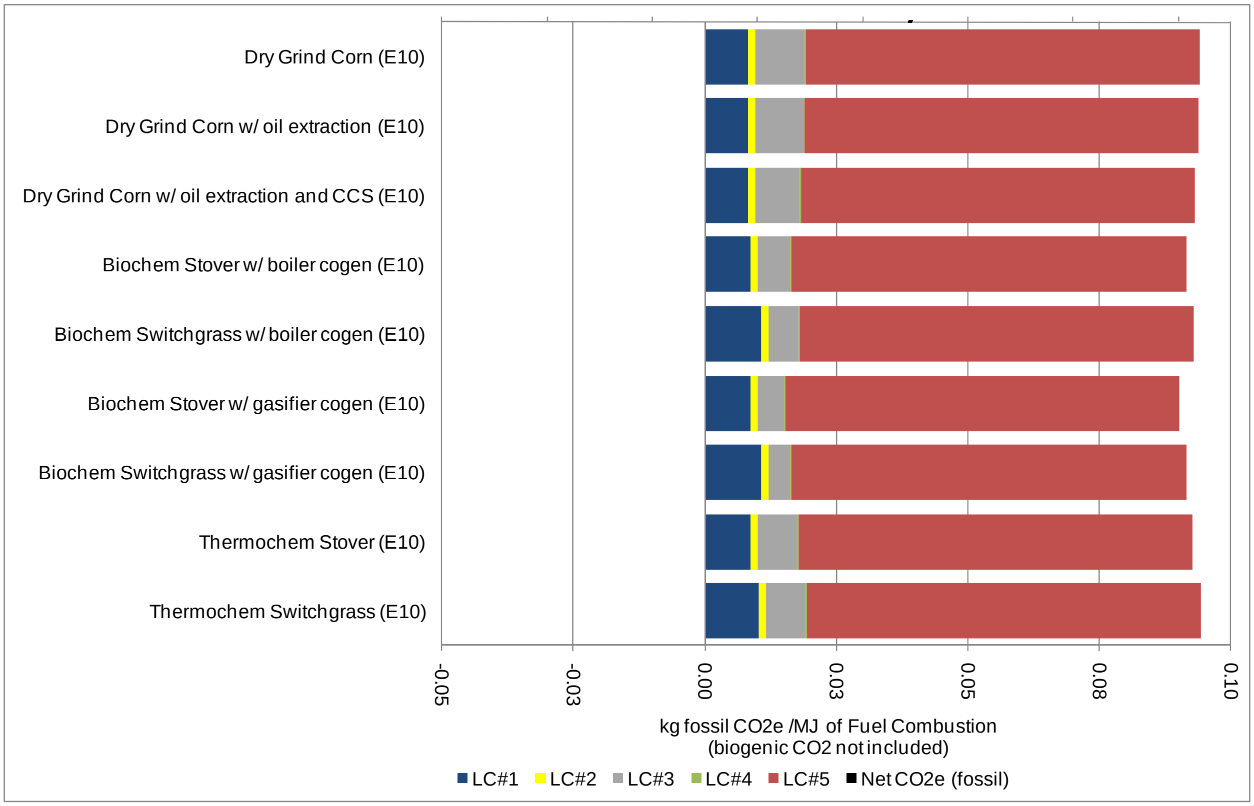

Figure 4-3: Fossil Carbon Dioxide Equivalents for each LC Stage of E10 Pathways

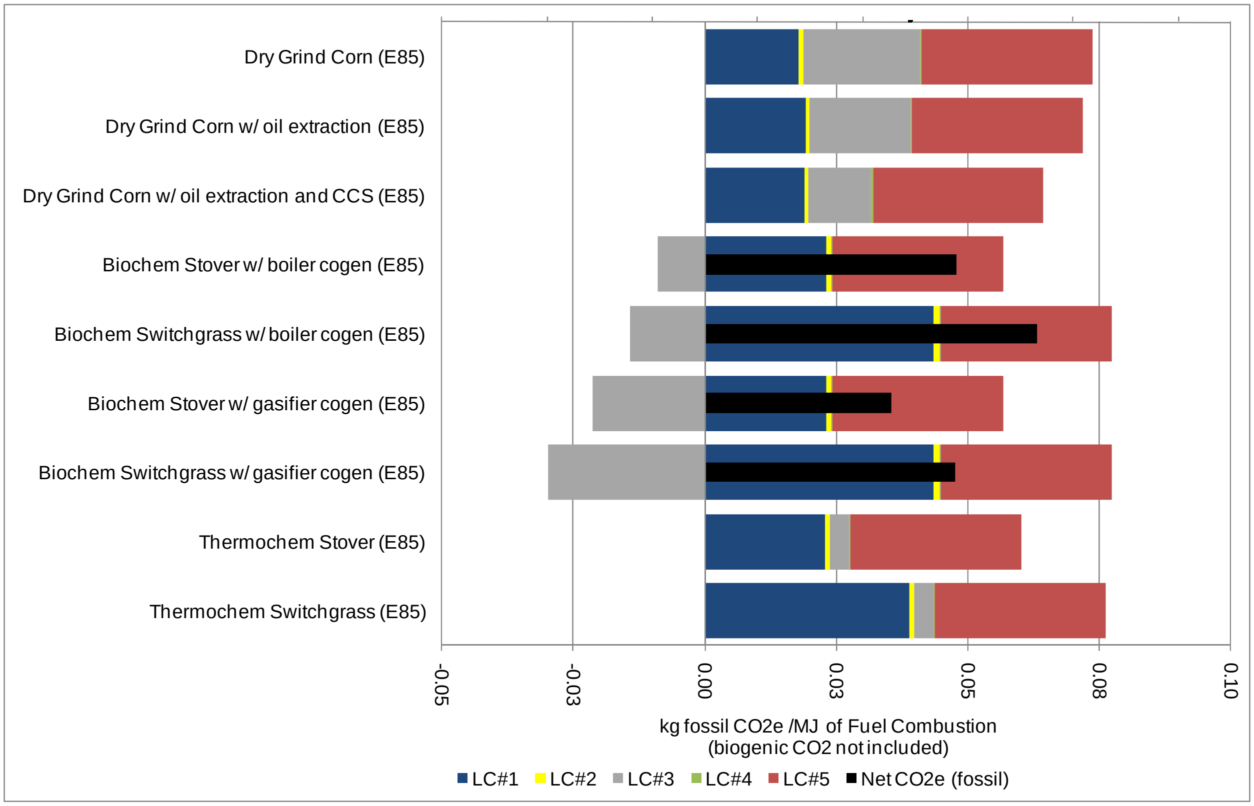

Figure 4-4: Fossil Carbon Dioxide Equivalents for each LC Stage of E85 Pathways

As shown in **Figure 4-1** and **Figure 4-2**, the net CO_2e emissions of the ethanol pathways range from 0.021 kg/MJ to 0.096 kg/MJ. The E85 pathway that uses biochemical conversion of corn stover and cogenerates electricity through the gasification of waste biomass has the lowest CO_2e emissions. The relatively low CO_2e emissions of this pathway are due to its high utilization of biomass as both a feedstock and a fuel. The biochemical ethanol plants of this analysis do not purchase fossil fuel-intensive energy (such as electricity or natural gas), but rather recover process energy from the biomass residuals of the lignocellulosic fermentation process. In fact, the energy recovery systems of the biochemical ethanol plants generate excess electricity that is sold to the electricity grid and, in turn, displaces CO_2e emissions from fossil-intensive power plants.

The E10 pathway that uses the advanced dry grind process (which includes corn oil extraction) has the highest CO_2e emissions. All E10 pathways fall within a CO_2e emission range of 0.090 kg/MJ and 0.096 kg/MJ. The range of CO_2e emissions for the E10 pathways coincides with the total life cycle emissions of conventional gasoline (0.092 kg CO_2e /MJ) as stated in NETL's baseline LCA of petroleum products (NETL, 2008). The composition of E10 is 90 percent gasoline (by volume), which explains why the CO_2e emissions of the E10 pathways of this analysis are comparable to the gasoline CO_2e emissions from NETL's petroleum baseline.

The CO_2e emissions of the dry grind and biochemical ethanol pathways are affected by the co-products of the ethanol plants. As discussed above, the biochemical ethanol plants sell co-produced electricity, which reduces the net CO_2e emissions of the biochemical ethanol pathways. Similarly, conventional dry grind ethanol plants sell DDGS (dried distillers grains with solubles), and the advanced dry grind plants sell DDGS and corn oil, both of which can displace conventional agricultural materials. However, unlike the sale of electricity, which displaces fossil fuel intensive power generation, the sale of DDGS and corn oil displace the growth of corn (the conventional source for animal feed) and soybeans (the conventional source for biodiesel), respectively.

This analysis also considers the implementation of CCS on an advanced dry grind ethanol plant. Due to the electricity requirements of CO_2 capture and the relatively small share of CO_2 emissions from the ethanol plant (in comparison to CO_2 emissions from the combustion of fuel in a passenger vehicle), CCS does not result in significant reductions in life cycle CO_2 emissions. The conventional dry grind pathway and advanced dry grind pathway have comparable life cycle CO_2e emissions.

The results for VOC emissions are shown for E10 and E85 in **Figure 4-5** and **Figure 4-6**, respectively. There is a significant difference between the VOC emissions of E10 and E85 pathways. In fact, two figures are shown for the VOC results in order to accommodate the different magnitudes of VOC results for E10 and E85. The VOC emissions of the E85 pathways that use corn grain and corn stover feedstocks are approximately ten times higher than the VOC emissions of the corresponding E10 pathways. The VOC emissions of the E85 pathways that use switchgrass are approximately two times higher than the VOC emissions of the corresponding E10 pathways. VOC emissions originate from the production of fertilizers used for biomass production in LC Stage #1. Switchgrass production requires less fertilizer than corn products production, and thus the switchgrass pathways have the lowest VOC emissions of this analysis. Corn stover requires additional makeup fertilizer to replenish nutrients that are lost due to stover harvesting, and thus the corn stover pathways have the highest VOC emissions of this analysis.

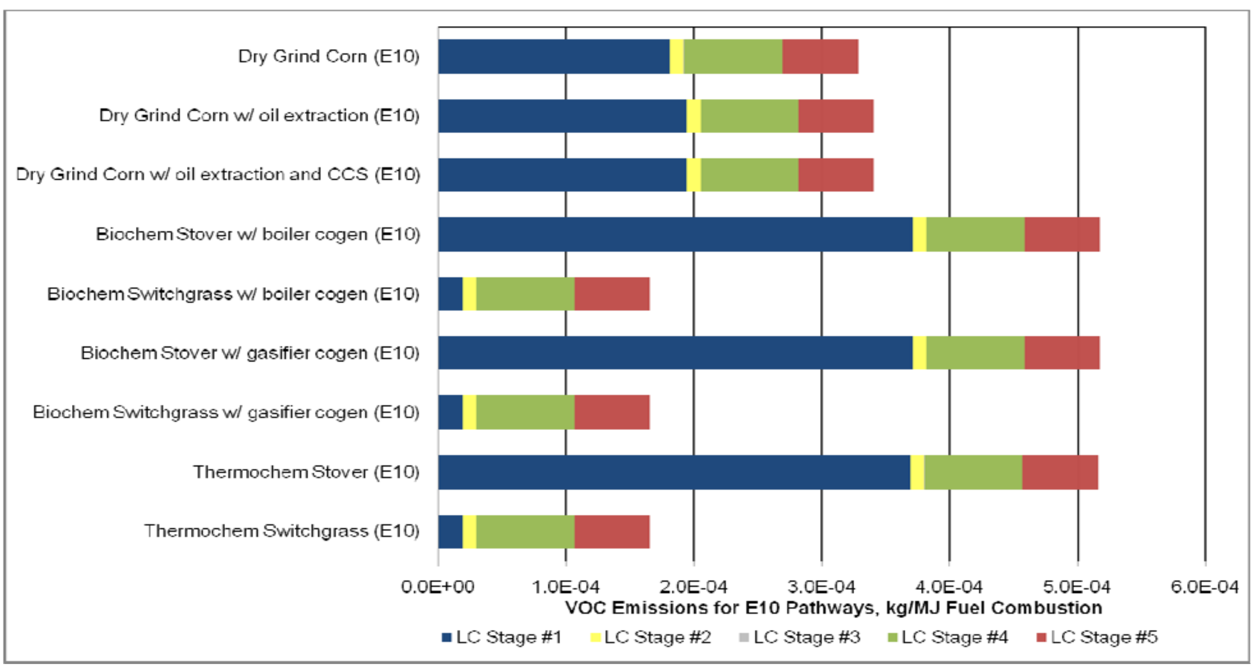

Figure 4-5: Volatile Organic Chemicals (VOC) Emissions from E10 Pathways (Cradle-to-Combustion)

As shown in **Figure 4-7**, the dry grind and biochemical pathways to E85 production have the highest PM emissions of this analysis. The majority of PM emissions occur during LC Stage #5 (combustion of fuel in a vehicle), but the elevated PM emissions of the dry grind and biochemical pathways are due to the relatively high PM emissions of dry grind and thermochemical ethanol plants in combination with the relatively high PM emissions from the diesel combustion that is associated with the growth of corn grain and corn stover.

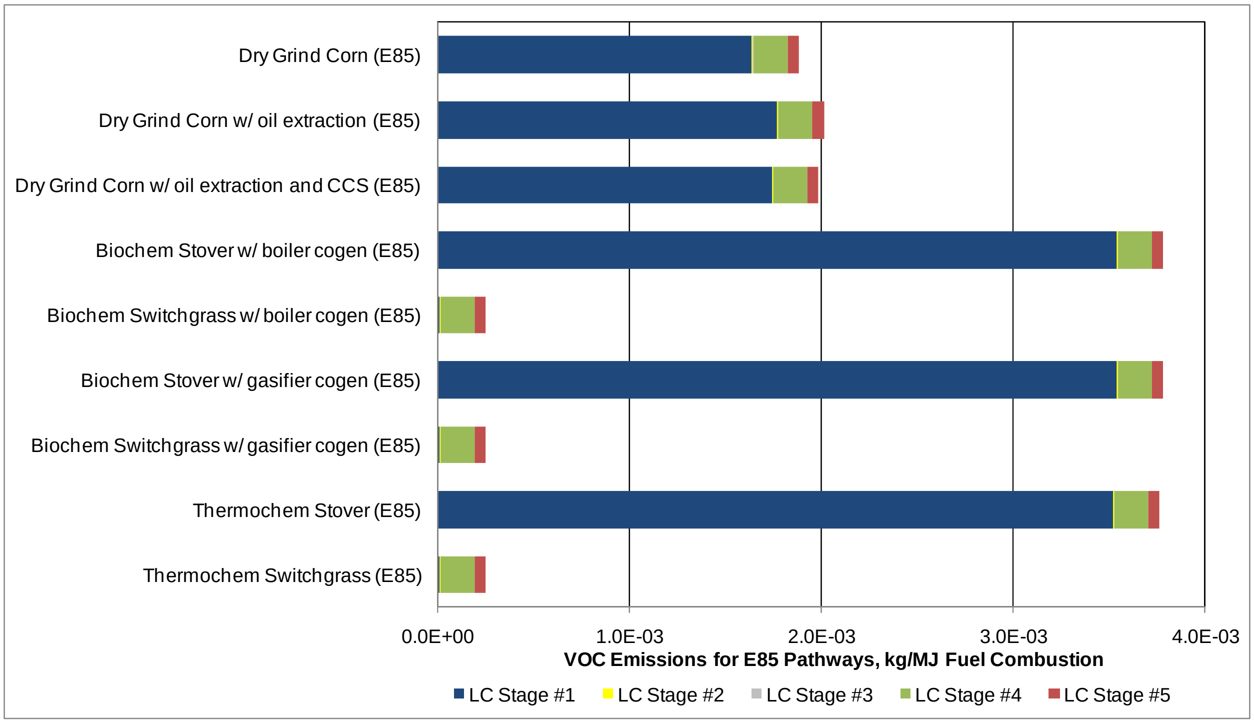

Figure 4-6: VOC Emissions from E85 Pathways (Cradle-to-Combustion)

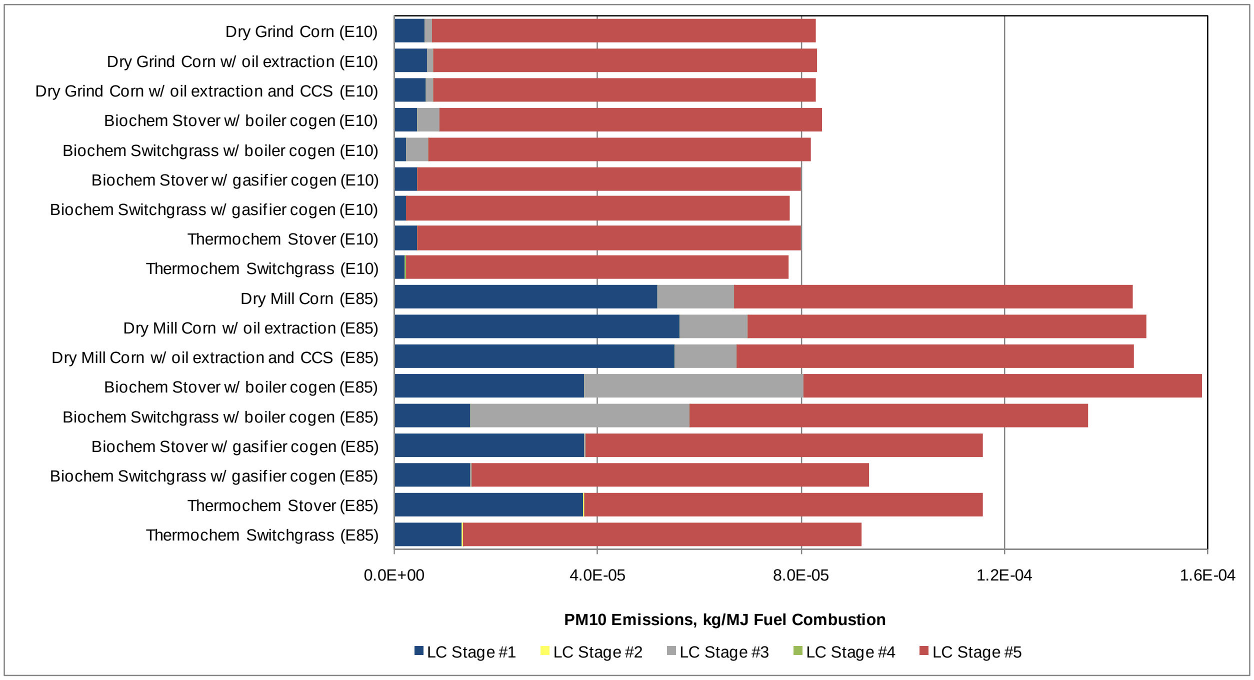

Figure 4-7: PM Emissions from E10 and E85 Pathways (Cradle-to-Combustion)

The results for water withdrawal indicate that the E85 pathways, which have a higher share of agricultural activities, have a significantly higher water use than the E10 pathways. The net water withdrawal is shown in **Figure 4-8**, which accounts for the water inputs and outputs of each of the five LC stages for each pathway. The withdrawal of water for LC Stage #1 is significantly higher than the other LC stage water flows and thus dominates the results. The data indicate that the production of switchgrass uses more water than the production of corn stover. Within the E85 scenarios, the switchgrass pathways use three to four times more water than the corn stover pathways.

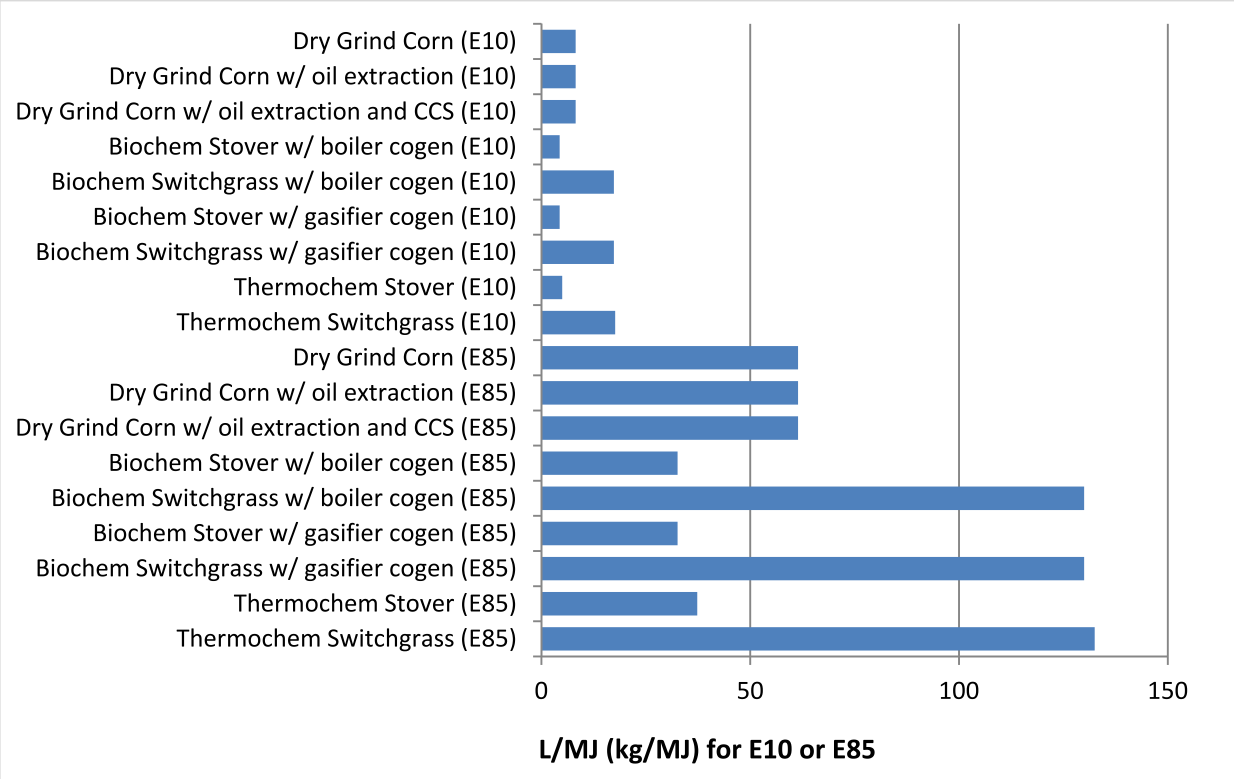

Figure 4-8: Net Water Withdrawal for E10 and E85 Pathways (Cradle-to-Combustion)

4.2 Life Cycle Costs (LCC)

The results of the LCC model show the RSP for the fuel produced by each pathway, as well as the associated capital and O&M costs for the pathways. The RSP is the price required to offset all capital and O&M costs incurred from LC Stage #1 through LC Stage #4 (from raw material extraction through the delivery of finished fuel to the consumer). The LCC model of this analysis will be compared to similar NETL LCAs that have well-to-tank cost boundaries for liquid fuels. Therefore the cost boundaries of this analysis do not include end vehicle use. RSP is normalized to the heating value of gasoline, which allows the comparison of E10 and E85 on an equivalent energy basis as well as allowing a fairer comparison between ethanol blends and conventional gasoline. The RSP results for the ethanol blends are normalized to an equivalent heating value of gasoline by factoring the RSP of each ethanol blend by the relative heating values of ethanol and gasoline. A gallon of gasoline has 1.03 times more energy than a gallon of E10 and 1.35 times more energy than a gallon of E85. The RSPs of E10 and E85 are multiplied by these factors in order to normalize them to the same energy basis of conventional gasoline.

The results of the LCC analysis demonstrate that the operating costs incurred during the 30-year period of ethanol production and distribution overshadow the capital costs for the construction of ethanol plants and fuel distribution infrastructure (pipelines, fuel terminals, and tanker trucks). The conventional ethanol dry grind process and the biochemical conversion of cellulose have the lowest RSPs of this analysis, ranging from \$3.00 to \$3.50 for the quantity of fuel required to deliver the same amount of energy as a gallon of gasoline. The thermochemical pathway that uses corn stover for E85 production has the highest RSP of this analysis (\$5.73 gasoline gallon equivalent). Detailed LCC results for the dry grind, biochemical, and thermochemical ethanol pathways are shown in the tables and figures below.

Another important attribute of the LCC analysis is that the majority of costs for the E10 pathways occur at the bulk loading terminal, while the majority of costs for the E85 pathways occur at the ethanol plants. Gasoline enters the boundaries of the LCC model at the bulk loading terminal; since E10 has a high proportion of gasoline, the majority of E10 costs occur at the bulk loading terminal. In contrast, the LCC model demonstrates that the majority of ethanol costs occur at ethanol plants; since E85 has a high proportion of ethanol, the majority of E85 costs are attributed to the activities at ethanol plants.

A corollary to the difference in the scale of gasoline inputs between the E10 and E85 pathways is the relative scale of total delivered product for the E10 and E85 pathways. This analysis has a fixed level of ethanol output at LC Stage #3 (ethanol production), but characterizes the delivery of two blending ratios of fuel at LC Stage #5 (vehicle use). Based on the relative blending ratios of the two fuels, the delivered volume of E10 is 7.4 times greater than the delivered volume of E85. Consequently, the annual required revenues calculated by the LCC model are approximately 7 times higher for the E10 pathways than for the E85 pathways, which is consistent with the difference in delivered volumes of the two fuel blends. However, the overall LCC results are provided in terms of RSP, which normalizes the disparate volumes of total delivered E10 and E85 to a basis of one gallon of delivered fuel.

The LCC results for the dry grind, biochemical, and thermochemical pathways to E10 and E85 production are shown in the following tables. **Table 4-1** shows results for E10 and E85 for the dry grind pathways, **Table 4-2** shows results for the biochemical pathways, and **Table 4-3** shows results for thermochemical pathways.

Table 4-1: LCC Results for Dry Grind Ethanol Pathways

Cost Category	Dry Grind (E10)	Dry Grind (E85)	Advanced Dry Grind (E10)	Advanced Dry Grind (E85)	Advanced Dry Grind w/ CCS (E10)	Advanced Dry Grind w/ CCS (E85)
Capital and Revenue Requirements						
Total Required Capital ($/daily bbl)	$23,300	$14,600	$49,700	$40,900	$68,600	$59,800
Capital ($MM/Yr)	$12.2	$7.6	$28.4	$21.4	$35.9	$31.3
Fixed O&M ($MM/Yr)	$95.3	$58.8	$95.3	$58.8	$95.3	$58.8
Utilities (Feedstock + Utilities - Coproduct Credits) ($MM/Yr)	$1,800	$180	$1,820	$190	$1,820	$200
Annual Required Revenue (Ethanol blend) ($MM/Yr)	$1,910	$240	$1,940	$270	$1,950	$290
RSP ($/gal)						
Fuel Production Facility	$0.22	$1.61	$0.28	$2.03	$0.29	$2.12
CO_2 Pipeline	$0.00	$0.00	$0.00	$0.00	$0.02	$0.12
Ethanol Pipeline	$0.01	$0.09	$0.01	$0.09	$0.01	$0.09
Bulk Storage facility	$2.97	$0.73	$2.97	$0.73	$2.97	$0.73
Tanker Truck & Trailer	$0.13	$0.13	$0.13	$0.13	$0.13	$0.13
Refueling Station	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RSP EtOH blend	$3.33	$2.57	$3.39	$2.98	$3.41	$3.20
RSP Gasoline Equivalents	$3.43	$3.46	$3.49	$4.03	$3.52	$4.32

Table 4-2: LCC Results for Biochemical Ethanol Pathways

Cost Category	Bio-chemical (CS) w/ FBC Cogen (E10)	Bio-chemical (CS) w/ FBC Cogen (E85)	Bio-chemical (SG) w/ FBC Cogen (E10)	Bio-chemical (SG) w/ FBC Cogen (E85)	Bio-chemical (CS) w/ Gasifier Cogen (E10)	Bio-chemical (CS) w/ Gasifier Cogen (E85)	Bio-chemical (SG) w/ Gasifier Cogen (E10)	Bio-chemical (SG) w/ Gasifier Cogen (E85)
Capital and Revenue Requirements								
Total Required Capital ($/daily bbl)	$47,600	$42,400	$47,600	$42,400	$44,800	$39,600	$44,800	$39,600
Capital ($MM/Yr)	$29.3	$26.1	$33.5	$26.1	$27.7	$24.4	$27.7	$24.4
Fixed O&M ($MM/Yr)	$132.7	$85.6	$132.7	$85.6	$132.7	$85.6	$132.7	$78.2
Utilities (Feedstock + Utilities - by-Product Credits) ($MM/Yr)	$2,150	$190	$2,150	$180	$2,140	$180	$2,130	$160
Annual Required Revenue (Ethanol blend) ($MM/Yr)	$2,310	$300	$2,310	$300	$2,300	$290	$2,290	$260
RSP ($/gal)								
Fuel Production Facility	$0.21	$1.56	$0.21	$1.51	$0.19	$1.41	$0.18	$1.32
CO_2 Pipeline	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Ethanol Pipeline	$0.01	$0.08	$0.01	$0.08	$0.01	$0.08	$0.01	$0.08
Bulk Storage facility	$2.97	$0.73	$2.97	$0.73	$2.97	$0.73	$2.97	$0.73
Tanker Truck & Trailer	$0.13	$0.13	$0.13	$0.13	$0.13	$0.13	$0.13	$0.13
Refueling Station	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
RSP EtOH blend	$3.32	$2.50	$3.32	$2.45	$3.30	$2.34	$3.29	$2.26
RSP Gasoline Equivalents	$3.42	$3.37	$3.42	$3.30	$3.40	$3.16	$3.39	$3.05

Table 4-3: LCC Results for Thermochemical Ethanol Pathways

Cost Category	Thermo-chemical (CS) (E10)	Thermo-chemical (CS) (E85)	Thermo-chemical (SG) (E10)	Thermo-chemical (SG) (E85)
Capital and Revenue Requirements				
Total Required Capital ($/daily bbl)	$47,200	$42,300	$47,200	$42,300
Capital ($MM/Yr)	$29.1	$26.0	$33.3	$26.0
Fixed O&M ($MM/Yr)	$129.3	$85.1	$129.3	$85.1
Utilities (Feedstock + Utilities - by-Product Credits) ($MM/Yr)	$1,910	$170	$1,910	$160
Annual Required Revenue (Ethanol blend) ($MM/Yr)	$2,070	$280	$2,070	$270
RSP ($/gal)				
Fuel Production Facility	$0.43	$3.19	$0.43	$3.08
CO_2 Pipeline	$0.00	$0.00	$0.00	$0.00
Ethanol Pipeline	$0.02	$0.17	$0.02	$0.17
Bulk Storage facility	$2.97	$0.73	$2.97	$0.73
Tanker Truck & Trailer	$0.14	$0.14	$0.14	$0.14
Refueling Station	$0.00	$0.00	$0.00	$0.00
RSP EtOH blend	$3.57	$4.24	$3.57	$4.13
RSP Gasoline Equivalents	$3.68	$5.73	$3.68	$5.58

The LCC results are also illustrated in **Figure 4-9** and **Figure 4-10**, which group the results according to E10 and E85 production.

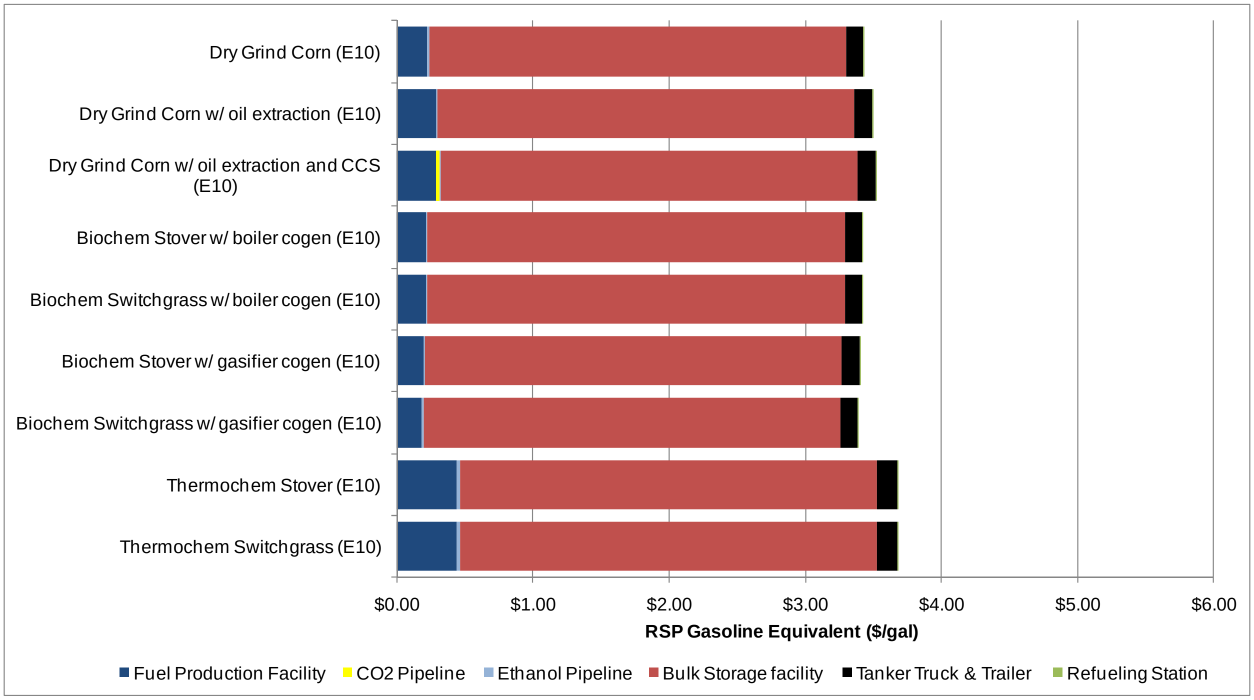

Figure 4-9: LCC Results for E10 Pathways

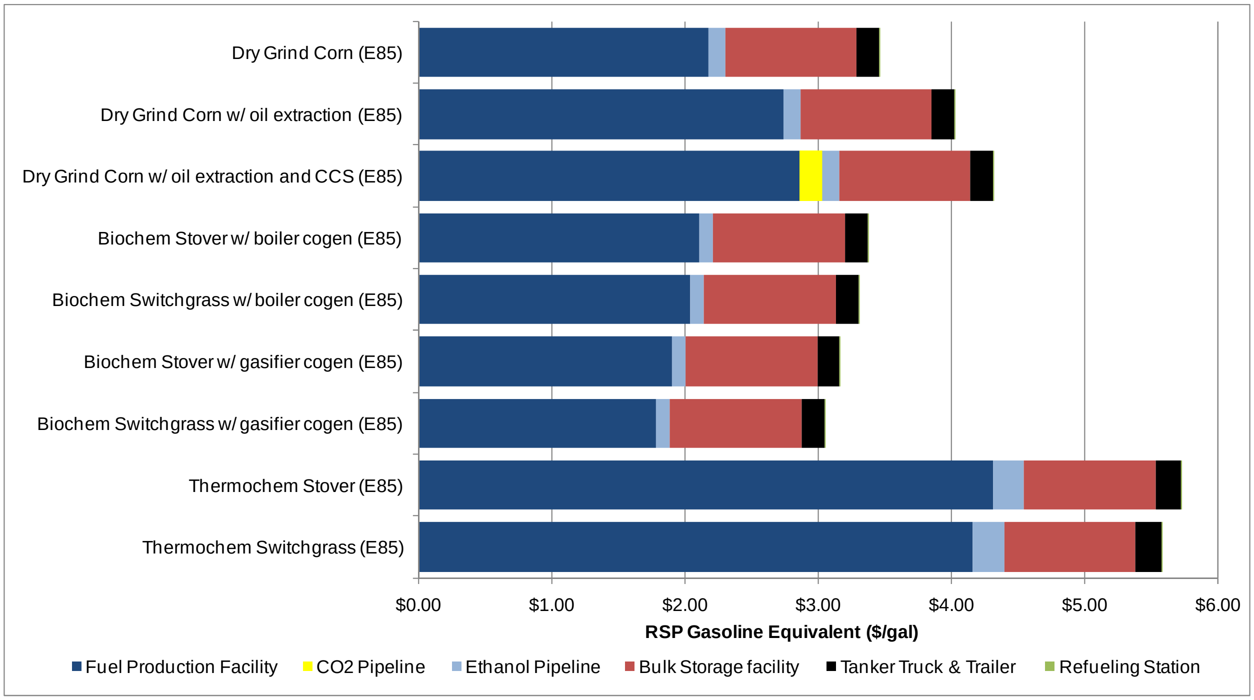

Figure 4-10: LCC Results for E85 Pathways

5.0 LAND USE

Analysis of land use impacts associated with a process or product is considered a central component of an LCA investigation, under both ISO 14044 (ISO, 2006) and ASTM (ASTM, 2007) procedural standards. The U.S. Environmental Protection Agency (EPA) recently released a Notice of Proposed Rulemaking for the Renewable Fuel Standard Program (RFS2; EPA, 2009a). Included in RFS2 is a proposed method for assessing land use change and associated GHG emissions that are relevant to this LCA. The land use analysis presented in this study is consistent with the proposed method presented in RFS2.

5.1 Definition of Primary and Secondary Impacts

Land use impacts can be roughly divided into primary and secondary. In the context of this study, primary land use impacts occur as a direct result of the LC processes needed to produce and deliver the ethanol-based fuels. Primary land use change is determined by tracking the change from an existing land use type (native vegetation, agricultural lands, and barren areas) to a new land use that supports production. Examples of facilities that may result in land use change include biomass feedstock cropping, pipelines, and refining facilities.

Secondary land use impacts are indirect changes in land use that occur as a result of the primary land use impacts. For instance, the conversion of food-producing agricultural land to non-food producing agricultural land (e.g., wood and paper crops or biofuel crops) would reduce available food supplies. A secondary impact might be the conversion of existing natural lands to farmland, to balance the deficit in food supply. Accurately predicting and quantifying most secondary impacts is problematic in that they are challenging to quantify and subject to interpretation. As a result, and because the scope of this study is not of sufficiently large scale to warrant detailed consideration of secondary effects such as displaced agriculture, this study considers only primary land use impacts.

5.2 Land Use Metrics

A variety of land use metrics, which seek to quantify changes in land use, have been devised in support of LCAs. Two common metrics used in process-oriented LCAs are transformed land area (e.g., area of land transformed from a pre-existing state) and GHG emissions (kg CO_2e). The transformed land area metric quantifies the area of land that is altered from a reference state, while the GHG metric quantifies the flux of carbon associated with that change (Fthenakis and Kim, 2008). Changes in carbon flux include the loss of carbon due to vegetation removal due to a transformation in land use, the loss of soil carbon due to a transformation in land use, and changes in the sequestration rate of carbon in vegetation due to a transformation in land use (e.g., the vegetation of a forest sequesters carbon at a higher rate than the vegetation of an agricultural site). **Table 5-1** summarizes the land use metrics included in this study.

The change in GHG emissions due to altered land use includes the following for each LC Stage as relevant:

- Quantity of GHGs emitted due to biomass clearing during construction.
- Quantity of GHGs emitted from soil carbon pools following land transformation.

- Comparison of existing state GHG sequestration to transformed state GHG sequestration, including biomass and soil carbon.

Table 5-1: Primary Land Use Change Metrics of this Analysis

Metric Title	Description	Units	Type of Impact
Transformed Land Area	Area of land that is altered from its original state to a transformed state during construction and operation of facilities.	square meters (acres)	Primary
GHG Emissions	Emissions of GHGs due to land transformation, as defined above.	kg CO_2e (lbs CO_2e)	Primary

GHG emissions from diesel fuel combustion during the construction of facilities are not accounted for in the land use assessment.

Additional land use metrics, such as potential damage to ecosystems or species, water quality changes, changes in human population densities, quantification of land quality (e.g. farmland quality), and many other land use metrics may conceivably be included in the land use analysis of an LCA. However, much of the data needed to support accurate analysis of these metrics are severely limited in availability (Canals *et al*., 2007; Koellner, 2007), or otherwise outside the scope of this study. Therefore, only transformed land area and GHG emissions are quantified for this study.

5.3 Land Use Method

The land use metrics used for this analysis quantify the land area that is transformed from its original state due to production of biomass fuels, including agriculture and supporting facilities. Calculations are based on a 30-year study period, or as relevant for each facility as discussed in the following text.

5.4 Transformed Land Area

The transformed land area metric was evaluated using crop yield data and assumptions regarding facility size, as well as satellite imagery and aerial photographs to assess and quantify original state land use. This was completed for each relevant facility and LC stage including agricultural production areas, the ethanol production facility, and pipelines. Only LC Stages #1, #3, and #4 include transformed land area (as shown in **Table 5-2**).

The assessment of transformed land area included quantification of the following:

- Amount of non-agricultural land converted to agricultural land for biomass production
    - Only switchgrass resulted in conversion of non-agricultural lands to agriculture, because it is assumed to be grown on degraded lands
    - Corn grain and corn stover were assumed to be grown on existing agricultural land

- Amount of land converted from its original to a transformed state for the ethanol production facility and CCS pipeline
- Amount of land converted from its original to a transformed state for the ethanol transport pipeline
- For land converted to construct the ethanol plant and pipelines, transformed state land use was characterized as "barren"
- The dry grind process is assumed to be an existing facility, so no land use impacts were quantified for this pathway
- Gasoline for blending was assumed to be produced within existing capacity for existing gasoline production lines; therefore, land use change associated with gasoline was assumed to be nil.

Table 5-2: Facility Locations

LC Stage No.	LC Stage Description	Facility	Location
LC Stage #1	Raw Material Acquisition	Agricultural Land for Biomass	Northwestern Iowa
LC Stage #2	Raw Material Transport	Not Considered	n/a
LC Stage #3	Fuel Production Facility	Ethanol Production Facility	Northwestern Iowa
		CCS Pipeline	Northwestern Iowa
LC Stage #4	Product Transport	Transport Pipeline	Northwestern Iowa
LC Stage #5	Product Use (combustion of fuel in vehicle)	Not Considered	n/a

Transformed land area is the area of land that would change from an existing use (e.g., forest), to a transformed land use (e.g., agriculture). Among switchgrass, corn stover, and corn grain, only switchgrass would result in land use change from non-agriculture to agriculture. Corn stover and corn grain would utilize existing agricultural lands, and no net change in land use would be indicated (e.g., agriculture to agriculture). **Table 5-3** summarizes the facility sizes that were assumed for this analysis.

Due to its proximity to the ethanol plant, original state land use for the CCS pipeline and ethanol transport pipeline was assumed to be the same as the ethanol plant. This assumption is reasonable given the homogenous original state land use types (e.g., agriculture in northwestern Iowa) in a 100-mile radius of the site and the fact that these facilities are typically not routed through an urban area.

5.5 Greenhouse Gases from Transformed Land

Once transformed land area was quantified, GHG emissions were assessed for the footprint of each facility, including agricultural feedstock production. To enable this analysis, a series of GHG emission factors were calculated based on available data from recent literature (Ravindranath and Ostwald, 2008; Jacinthe and Lal, 2009; Jones and Donnelley, 2004; Nicodemus *et al.*, 2003).

GHG emissions due to land transformation can result from (1) loss of carbon stored in aboveground vegetation (e.g., standing stock), (2) changes in the amount of carbon stored in soil organic matter (SOM) pool, and (3) forgone carbon sequestration (CO_2 uptake that would have taken place under the original state land use, but that would not occur under the transformed state land use). The sum of these three categories is equivalent to the total GHG emissions associated with the land use change in question. Note that for the purposes of this LCA, CO_2 that is absorbed by plants due to photosynthesis is not accounted for by the land use model, but is instead incorporated into the emissions inventory used by the GaBi life cycle model.

Table 5-3: Facility Sizes

Facility	Land Area Utilized	Units	Key Assumptions
Ag Land for Biomass: Corn Grain	0 to 756 million	m^2	Calculated based on plant feedstock requirements and biomass yield for each case
Ag Land for Biomass: Corn Stover	766 million	m^2	Calculated based on plant feedstock requirements and biomass yield for each case
Ag Land for Biomass: Switchgrass	1.21 billion	m^2	Calculated based on plant feedstock requirements and biomass yield for each case
Ethanol Plant	322,000 to 368,000	m^2	Variable according to plant capacity
CCS Pipeline	2.45 million	m^2	50 foot construction width, 100-mile length
Transport Pipeline	2.45 million	m^2	50 foot construction width, 100-mile length

Loss of carbon stored in aboveground vegetation was assessed by quantifying the amount of aboveground biomass carbon contained in the original state land use, minus the amount contained under the transformed state land use. The difference between these two numbers represents the change in total aboveground biomass carbon storage in the affected area (**Table 5-4**). For the purposes of this analysis, consistent with assumptions promulgated under RFS2 (EPA, 2009a), it is assumed that all aboveground biomass carbon that is removed from the site is emitted to the atmosphere as CO_2. This assumption is likely accurate for most land use types, where grass or small diameter forest may be landfilled, utilized as biomass feedstock, or otherwise allowed to decay. This assumption does not, however, account for the use of trees as mulch or timber for construction purposes, which could substantially reduce standing stock emissions. Loss of carbon stored in aboveground biomass represents a single removal event, and is applied once within the model, representative of the land transformation that would occur at the onset of the study.

For carbon stored in the SOM pool, changes were assessed by quantifying the amount of soil organic carbon (SOC) stored in the original state land use, minus the amount stored under the transformed state land use. The difference between these two numbers represents the total change in the SOC pool. As shown in **Table 5-5**, most land use transformations would result in a net reduction of the SOC pool, except for a change from barren to agricultural land use. For the purposes of this analysis, it is assumed that all reductions in the SOC pool would result in concurrent CO_2 emissions. Increases in the SOC pool (e.g., only for transformation from barren to agriculture) represent net CO_2 uptake, and are shown as negative values in the following tables (**Table 5-4, Table 5-5, Table 5-6**).

Table 5-4: Removal of Standing Stock Biomass: Net CO2e Emissions

Original State Land Use	Transformed State Land Use	Emission (kg CO_2E/m^2)	Reference
Agriculture	Agriculture	0	Ravindranath and Ostwald, 2008
Agriculture	Barren	0.19	Ravindranath and Ostwald, 2008
Grassland	Agriculture	0.53	Ravindranath and Ostwald, 2008
Grassland	Barren	0.72	Ravindranath and Ostwald, 2008
Forest	Agriculture	5.49	Ravindranath and Ostwald, 2008
Forest	Barren	5.67	Ravindranath and Ostwald, 2008
Barren	Agriculture	-0.19	Ravindranath and Ostwald, 2008

Note: negative numbers represent net uptake

Table 5-5: Changes in Soil Organic Carbon Pool Size: Net CO_2e Emissions

Original State Land Use	Transformed State Land Use	Emission (kg CO_2e/m^2)	Reference
Agriculture	Agriculture	0	Ravindranath and Ostwald, 2008
Agriculture	Barren	3.80	Ravindranath and Ostwald, 2008
Grassland	Agriculture	15.6	Ravindranath and Ostwald, 2008
Grassland	Barren	19.4	Ravindranath and Ostwald, 2008
Forest	Agriculture	1.62	Ravindranath and Ostwald, 2008
Forest	Barren	5.42	Ravindranath and Ostwald, 2008
Barren	Agriculture	-3.80	Ravindranath and Ostwald, 2008

Note: negative numbers represent net uptake

Forgone carbon sequestration is biomass CO_2 uptake that would have taken place had the original state land use continued to persist throughout the study period, but which did not due to land transformation/removal of original state biomass. Forgone carbon sequestration is carbon removed from the atmosphere and stored as biomass. As shown in **Table 5-6**, most land use transformations would result in a net reduction in annual sequestration. Note that transformation from barren to agricultural land would result in a net increase in annual sequestration, resulting in a negative emission value, as shown in **Table 5-6**.

Table 5-6: Forgone Carbon Sequestration: Net CO_2e Emissions

Original State Land Use	Transformed State Land Use	Emission (kg CO_2e/m^2-yr)	Reference
Agriculture	Agriculture	0	Jacinthe and Lal, 2009
Agriculture	Barren	0.0525	Jacinthe and Lal 2009
Grassland	Agriculture	0.348	Jones and Donnelley, 2004; Jacinthe and Lal, 2009
Grassland	Barren	0.4	Jones and Donnelley, 2004
Forest	Agriculture	0.298	Nicodemus *et al.*, 2003; Jacinthe and Lal, 2009
Forest	Barren	0.35	Nicodemus *et al.*, 2003
Barren	Agriculture	-0.0525	Jacinthe and Lal, 2009

Note: negative numbers represent net uptake

For all new construction, except pipelines, the transformed land use state was assumed to persist throughout the entire 30-year study period, and forgone sequestration was assessed over that time period. It was assumed that pipelines would be buried and would require trenching and land transformation associated with construction, but would not result in permanent land transformation. Therefore, it was assumed that any SOM or standing stock carbon lost during construction would be regenerated following a two-year period of re-vegetation; afterward the land would revert to its original state land use. Therefore, for pipelines only forgone carbon sequestration for a period of two years was assumed.

5.6 Greenhouse Gas Emissions Associated with Land Use

Previous results on land transformation are used as input to calculate GHG emissions. As shown in **Table 5-4**, **Table 5-5**, and **Table 5-6** above, GHG emissions are associated with three activities in particular: (1) loss of standing stock carbon (e.g., aboveground vegetation), (2) loss of SOM, and (3) changes in carbon sequestration uptake rates during the study period (30 years). By applying the GHG emissions from these three activities to the transformed land area shown in **Figure 5-1**, the total GHG emissions related to the land use of each pathway can be determined.

Figure 5-2 shows the GHG emissions related to land use for each ethanol pathway. **Figure 5-1** shows the GHG emissions according to original land type, while **Figure 5-2** shows the GHG emissions according to LC stage (note that no land use change occurs for LC Stage #2 and LC Stage #5).

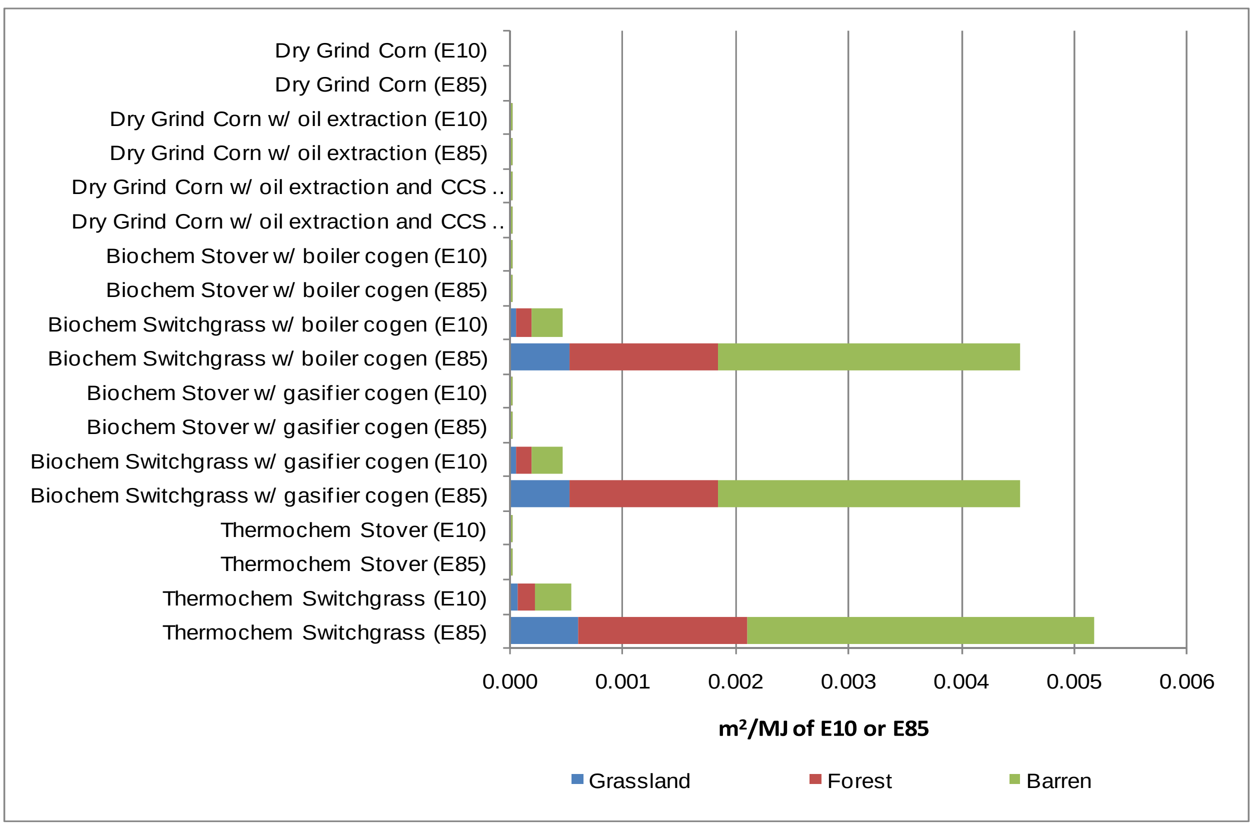

Figure 5-1: Total Transformed Land Area (m^2/MJ)

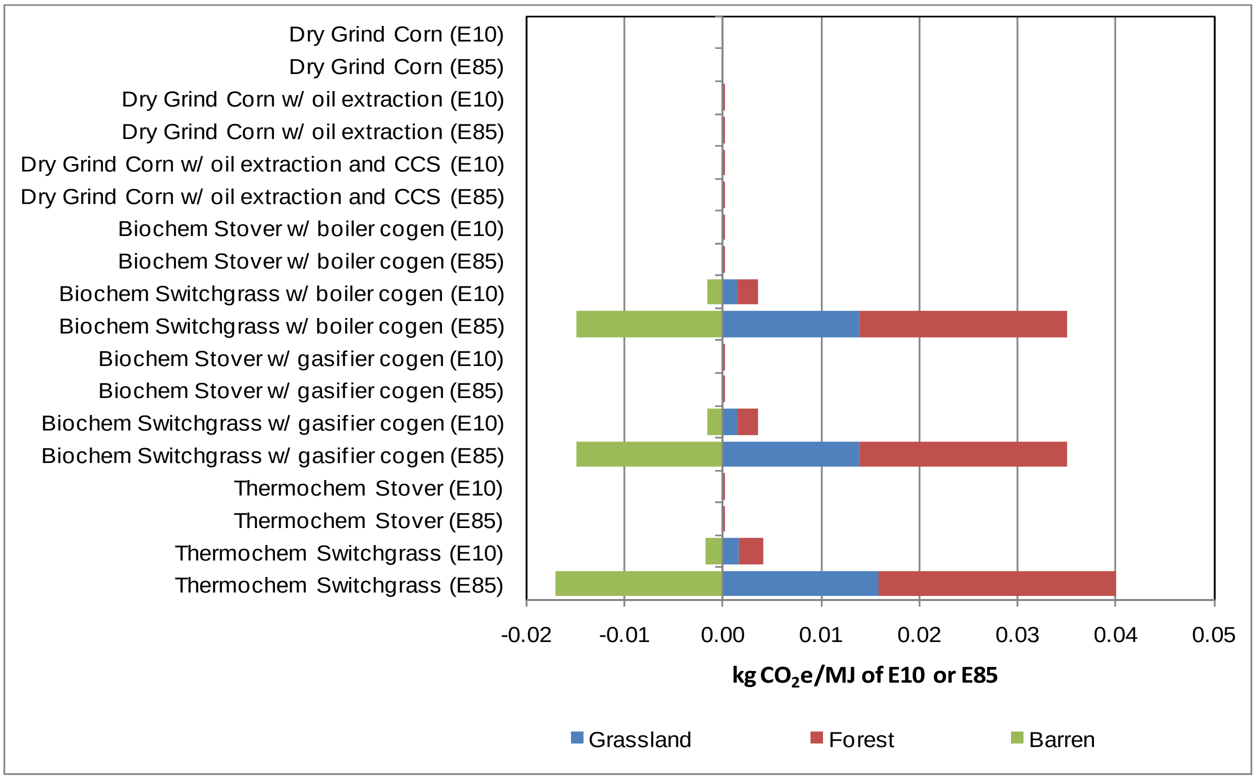

Figure 5-2: Total GHG Emissions (kg CO_2/MJ)

6.0 SENSITIVITY ANALYSIS

Sensitivity analysis quantifies the impact of changes in system parameters, including assumptions, on the final results. Results from a sensitivity analysis indicate the magnitude of change in output values given specified variation of a system parameter. A parameter is said to be sensitive if a small change in the parameter causes a relatively large change in a final result.

Sensitivity analysis is used when the value of a parameter is uncertain or variable. Reasons for the uncertainty could be, for example, due to poor quality data or a questionable emissions profile for a specific piece of equipment. Knowing the impact of the questionable data or assumption on the final results is helpful to assuage data quality concerns.

6.1 Sensitivity of Environmental LCI Assumptions

Three parameters were chosen for LCI sensitivity analysis: (1) biomass transport distance, (2) the displacement ratio between DDGS and animal feed, and (3) quantity of construction materials, as shown in **Table 6-1**. Biomass transport distance was chosen as a variable for sensitivity analysis because in comparison to petroleum and other conventional fuels, the supply chains of biofuels (including ethanol) have relatively short transportation distances between the site of raw material extraction and fuel production facility, making it necessary to evaluate the uncertainty in biomass transportation parameters. The displacement ratio between DDGS and animal feed was a chosen variable for the sensitivity analysis because literature on ethanol production reports a range in displacement ratios, from 0.8 to 1.2. Finally, the quantity of construction materials was chosen as a variable for sensitivity analysis because no data are available to develop a construction profile specific to each pathway of this analysis, making it necessary to understand the potential error caused by inadequate construction data.

Biomass transport distance is pertinent to all pathways; however, only the conventional dry grind process (E85) and the biochemical conversion with FBC cogeneration (E85) were subjected to sensitivity analysis, since it was assumed that these results could be applied to the other pathways. Similarly, these two scenarios were also used to measure the sensitivity of the results to the quantity of construction materials. The conventional dry grind pathway was used to measure the sensitivity of the displacement ratio of DDGS to animal feed under the assumption that the results can be applied to the other dry grind scenarios that have DDGS as a co-product.

Table 6-1: Sensitivity Analysis Parameters for Environmental LCI Model

Parameter	LC Stages Affected	Study Value	Sensitivity Value	Source/Reasoning
Biomass Transport Distance	LC Stage #2 (Raw Material Transport)	Corn grain: 42 mi; Corn stover: 46 mi	Corn grain: 84 mi; Corn stover: 92 mi	To assess changes due to altered transport distance.
DDGS/Animal Feed Displacement Ratio	LC Stage #3 (Fuel Production Facility)	1	0.8 to 1.2	Vary within possible displacement ranges reported in literature.
Construction Materials	LC Stages #1 through #4 (Raw Material Acquistion through Product Delivery)	Totals for steel, concrete, etc.	3 times increase (200 percent)	To account for replacement parts and imprecise data.

6.1.1 Biomass Transport Distance

The distance that biomass transport trucks traveled varies according to the type of biomass. For corn grain an average round-trip distance of 42 miles is the base case; for corn stover, the base case is an average round-trip distance of 46 miles. To assess the effects of increased biomass transport distance on LC emissions, the round trip transport distance for each biomass feedstock was doubled for the sensitivity analysis.

The primary operational change that results from increasing the biomass transport distance is the increasing amount of diesel fuel consumed. Only air pollutants that are contained in substantial amounts in diesel exhaust were considered. The results of the sensitivity analysis of biomass transport distances are shown in **Table 6-2** and **Table 6-3**.

For the transport of corn grain, no emissions change more than one percent between the study value and the sensitivity value. The transport of corn stover, however, is more sensitive to changes in transportation distances. For the transport of corn stover, the 100 percent increase in distance increases CO_2 emissions by approximately 1 percent, methane emissions by 2.8 percent, particulate matter by 7.1 percent, and sulfur oxide emissions by 12 percent. The relatively high increases in particulate matter and sulfur oxides are due to the fact that the base case LC results for the biochemical ethanol plant that uses corn stover have relatively low emissions of particulates and sulfur oxides (due to the sale of electricity to the MROW grid). Thus, the magnitude of the increased particulate and sulfur oxide emissions is the same for the two cases, but the percent change is greater for the biochemical pathway.

Note that SO_x emissions are negative for the biochemical scenario (as shown in **Table 6-3**). Negative SO_x emissions result from the displacement of grid electricity by electricity that it co-generated and sold by biochemical ethanol plants.

Table 6-2: Study and Sensitivity Values of Emissions for Corn Grain Biomass Transport Distance; Conventional Ethanol Dry Grind; All Stages; kg/MJ

Emissions (kg/MJ)	Study Value (42 miles)	Sensitivity Value (84 miles)	% Change
CH_4	7.69E-05	7.72E-05	0.381%
CO	3.83E-03	3.83E-03	0.004%
CO_2	6.06E-02	6.06E-02	0.127%
Pb	4.86E-09	4.87E-09	0.026%
Hg	3.66E-10	3.67E-10	0.029%
N_2O	3.76E-05	3.76E-05	0.005%
NO_X	1.71E-04	1.71E-04	0.054%
PM	1.83E-07	1.85E-07	0.749%
SO_X	1.36E-04	1.37E-04	0.083%
VOC	1.72E-03	1.72E-03	0.003%

Table 6-3: Study and Sensitivity Values of Emissions for Corn Stover Biomass Transport Distance; Biochemical Ethanol Facility; All Stages; kg/MJ

Emissions (kg/MJ)	Study Value (46 miles)	Sensitivity Value (92 miles)	% Change
CH_4	4.64E-05	4.77E-05	2.77%
CO	3.82E-03	3.82E-03	0.018%
CO_2	3.25E-02	3.28E-02	1.04%
Pb	4.97E-09	4.98E-09	0.112%
Hg	2.29E-10	2.29E-10	0.206%
N_2O	4.36E-05	4.36E-05	0.018%
NO_X	1.72E-10	1.72E-10	0.004%
PM	8.48E-08	9.08E-08	7.11%
SO_X	-4.16E-06	-3.66E-06	11.9%
VOC	3.69E-03	3.69E-03	0.044%

6.1.2 DDGS/Animal Feed Displacement Ratio

The sensitivity analysis varied the displacement ratio between co-product DDGS and animal feed. The base case assumes 1 kilogram of DDGS displaces 1 kilogram of animal feed. In the sensitivity case, 1 kilogram of DDGS displaces 0.8 kilograms of animal feed in the conventional dry grind ethanol plant (E85) pathway. A second sensitivity case for the same pathway was run assuming 1 kilogram of DDGS displaces 1.2 kilograms of animal feed. The results are shown in

Table 6-4. The sensitivity analysis shows that most air emissions do not change more than one percent with a 20 percent change in the displacement rate. Two exceptions are nitrous oxide (N_2O) and VOCs, which increase by approximately 9 percent with a 20 percent decrease in the displacement rate and which decrease by approximately 9 percent with a 20 percent increase in the displacement rate. The sensitivity of these two emissions (N_2O and VOC) is due to the change in emissions associated with the amount of fertilizer used for the growing of corn.

Table 6-4: Study and Sensitivity Values of DDGS to Animal Feed Displacement; Conventional Ethanol Dry Grind; All Stages; kg/MJ

Emissions (kg/MJ)	Study Value 1 DDGS to 1 feed	Sensitivity Value Low (1 DDGS to 0.8 feed	Sensitivity Value High (1 DDGS to 1.2 feed	% Change Between Study Value and Low Displacement	% Change Between Study Value and High Displacement
CH_4	7.69E-05	7.75E-05	7.62E-05	0.850%	-0.850%
CO	3.83E-03	3.83E-03	3.83E-03	0.0202%	-0.0202%
CO_2 (fossil)	6.06E-02	6.11E-02	6.00E-02	0.890%	-0.890%
Pb	4.86E-09	4.90E-09	4.83E-09	0.680%	-0.680%
Hg	3.66E-10	3.69E-10	3.64E-10	0.760%	-0.760%
N_2O	3.76E-05	4.08E-05	3.45E-05	8.33%	-8.33%
NO_X	1.71E-04	1.72E-04	1.69E-04	0.808%	-0.808%
PM	1.83E-07	1.85E-07	1.82E-07	0.740%	-0.740%
SO_X	1.36E-04	1.37E-04	1.36E-04	0.680%	-0.680%
VOC	1.72E-03	1.88E-03	1.56E-03	9.33%	-9.33%

6.1.3 Construction Materials

There are significant data gaps in the study associated with the quantity of construction materials used throughout the LC. There was insufficient data on the material profiles of farming equipment (LC Stage #1) and vehicles for road transport (LC Stage #2, and Stage #4). Limited data were available for the ethanol production facilities (Stage #3). Additionally, there is an overall lack of data available on the energy input required to form and assemble components into equipment and equipment into systems.

The sensitivity analysis varied the quantity of construction materials required in LC Stages #1 through #4. LC Stage #5 does not require construction materials. A threefold increase (200 percent) was chosen to evaluate the sensitivity of construction materials to the LC results. This threefold increase is the multiplier used for evaluating the sensitivity of construction materials in previous NETL LCAs.

The results of the sensitivity analysis of construction materials for the dry grind ethanol plant for the E85 pathway are shown in **Table 6-5**. The results of the sensitivity analysis of construction materials for an ethanol plant that uses biochemical conversion of corn stover to produce ethanol for the E85 pathway are shown in **Table 6-6**. Lead and mercury, which increase by 177 percent and 151 percent, respectively, are the two air emission species affected most by the 200 percent increase in construction materials. This demonstrates that lead and mercury are highly concentrated in the construction data of this analysis. Concrete and steel are two key inputs of the construction processes of this analysis, and lead and mercury originate from the material extraction and energy requirements for the production of steel and concrete. The CO_2 and methane emissions, which are also characteristic of concrete and steel production, increase by 18 percent and 10 percent, respectively, with a 200 percent increase in construction materials; these increases are not as significant as for lead and mercury emissions. Since all pathways involve construction materials, all would be similarly sensitive to changes in the amount of construction materials used.

Table 6-5: Study and Sensitivity Values of Construction Materials; Conventional Ethanol Dry Grind Plant; All Stages; kg/MJ

Emissions (kg/MJ)	Study Value	Sensitivity Value	% Change
CH_4	8.28E-05	9.80E-05	18.3%
CO	3.83E-03	3.91E-03	1.95%
CO_2	1.09E-01	1.20E-01	9.76%
Pb	5.00E-09	1.39E-08	177%
Hg	3.75E-10	9.42E-10	151%
N_2O	7.90E-05	7.93E-05	0.410%
NO_X	1.69E-04	1.86E-04	10.2%
PM	1.05E-04	1.05E-04	0.00%
SO_X	1.37E-04	1.76E-04	28.0%
VOC	1.23E-03	1.23E-03	0.170%

Table 6-6: Study and Sensitivity Values of Construction Materials - Biochemical Ethanol Plant - All Stages

Emissions (kg/MJ)	Study Value	Sensitivity Value	% Change
CH_4	4.79E-05	6.38E-05	33.1%
CO	3.82E-03	3.90E-03	2.13%
CO_2	7.80E-02	8.96E-02	14.8%
Pb	5.01E-09	1.55E-08	210%
Hg	2.25E-10	8.94E-10	298%
N_2O	6.78E-05	6.81E-05	0.540%
NO_X	1.35E-04	1.53E-04	14.0%
PM	1.38E-04	1.38E-04	0.00%
SO_X	1.39E-05	5.45E-05	292%
VOC	1.74E-03	1.74E-03	0.120%

6.2 Sensitivity of LCC Assumptions

A sensitivity analysis was performed by varying feedstock, co-product, and capital costs as listed in **Table 6-7.** Four parameters were chosen: (1) corn stover feedstock cost, (2) DDGS co-product selling price, (3) corn oil co-product selling price, and (4) ethanol plant capital costs. Corn stover feedstock cost was chosen as a variable for the sensitivity analysis because of the uncertainty in future corn stover costs, especially if corn stover transitions from an agricultural residue to viable energy feedstock. The selling prices of DDGS and corn oil were chosen as variables for the sensitivity analysis because an increase in dry grind ethanol production could flood the market with excess corn oil and DDGS and, in turn, alter the market values of DDGS, corn oil, and substitute products. The capital costs of the ethanol plants were a chosen variable for the sensitivity analysis because the data of this analysis did not have capital cost data specific to each ethanol production pathway, and thus a sensitivity analysis indicates the extent to which the non-specific capital cost data can affect the conclusions of the analysis.

The LCC sensitivity analysis was performed only for the E85 pathways because most of the data uncertainty of this analysis was due to the agricultural and ethanol production processes, which contribute more to the E85 pathways than to the E10 pathways. The results of the LCC sensitivity analysis are expressed on the basis of the quantity of ethanol that has the same energy as a gallon of gasoline (a gallon of gasoline has 1.35 times more energy than a gallon of E85).

Table 6-7: Sensitivity Analysis Parameters for LCC Model

Parameter	LC Stages Affected	Study Value	% Adjustment
Corn stover feedstock price	3	$87.00/ton	+/- 25%
DDGS co-product selling price	3	$0.136/kg	+/- 25%
Corn oil co-product selling price	3	$0.353/kg	+/- 25%
Ethanol plant capital costs	3	Variable, depending on plant technology	+/- 25%

6.2.1 Corn Stover Feedstock Cost

The current market value prices corn stover as a byproduct stream, not as a preferred feedstock to ethanol production. The projected value of $87.00/ton is the default value in the LCC model and is based on the assumption that future cellulosic ethanol plants will favor the emergence of corn stover as a preferred biomass feedstock. The cost of corn stover feedstock was varied by +/-25 percent from the projected future value of $87.00/ton. As illustrated in **Figure 6-1**, when the cost of corn stover is increased or decreased by 25%, the RSP (in terms of equivalent gasoline energy) of the E85 is increases or decreases by at least 12 percent.

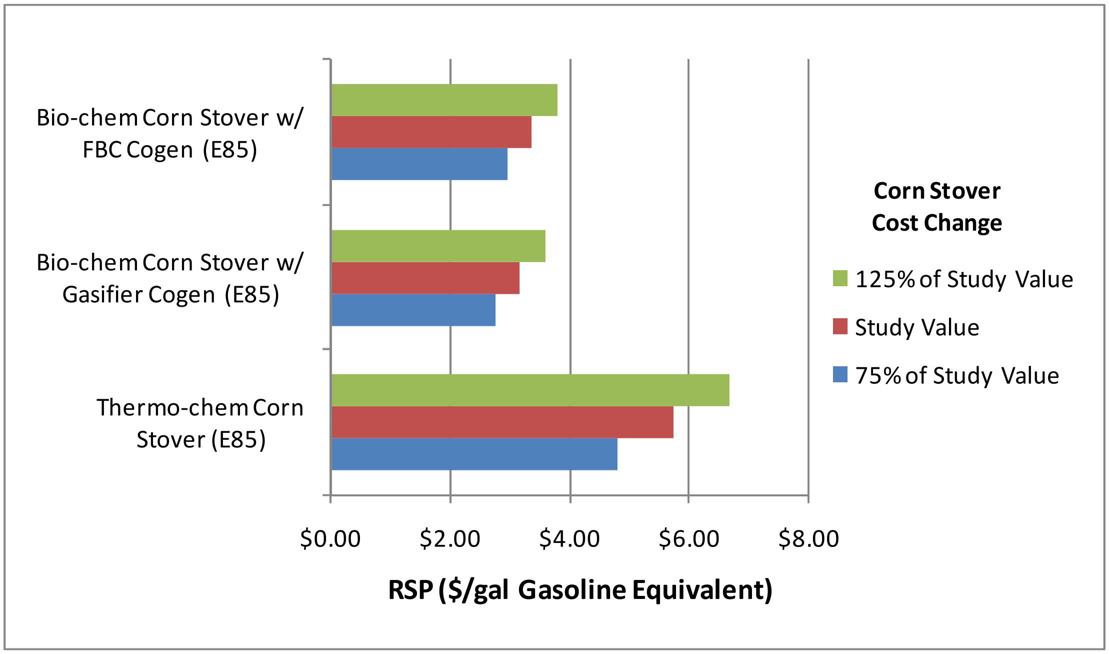

Figure 6-1: LCC Sensitivity of Corn Stover Cost

6.2.2 DDGS and Corn Oil Selling Prices

The selling price of DDGS and corn oil, which are co-products of dry grind ethanol production, was subjected to sensitivity analysis. Conventional and advanced dry grind ethanol plants can sell DDGS as a high protein animal feed. Additionally, advanced dry grind ethanol plants can sell corn oil as a feedstock for bio-diesel production. As shown in **Figure 6-2**, when the price of DDGS is increased or decreased by 25 percent, the change in RSP (in terms of equivalent gasoline energy) of E85 from corn ethanol plants is insignificant (less than a one percent change). As illustrated in **Figure 6-3**, when the price of corn oil is increased or decreased by 25 percent, the RSP of E85 changes by less than one percent. The sensitivity analysis indicates that a large change in the selling price of co-products results in a small change in RSP, which indicates that the majority of revenue of the dry grind ethanol plants is due to the sale of ethanol.

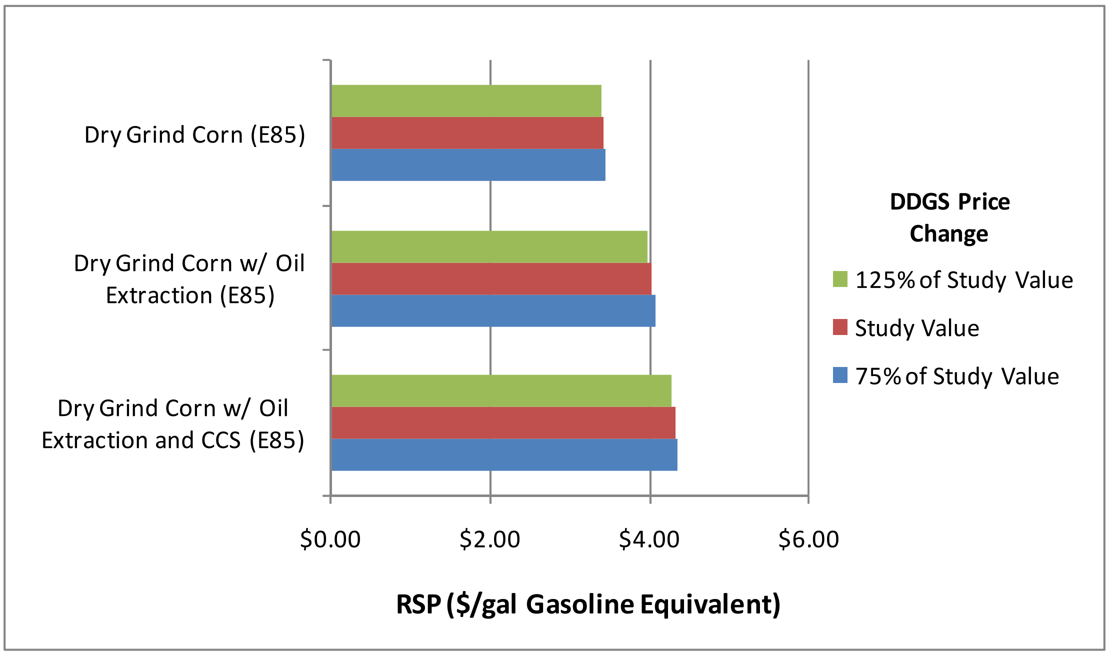

Figure 6-2: LCC Sensitivity of DDGS Selling Price

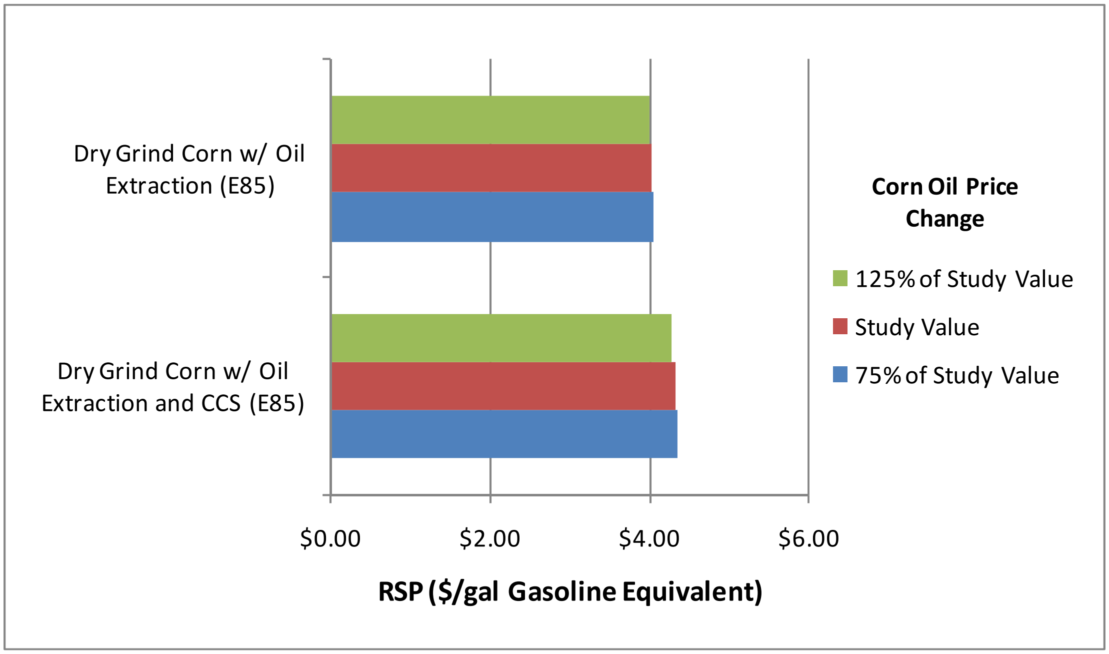

Figure 6-3: LCC Sensitivity of Corn Oil Selling Price

6.2.3 Ethanol Plant Capital Costs

The capital costs of the ethanol plants were subjected to a sensitivity analysis. As shown in **Figure 6-4**, when the capital costs of the ethanol plants are increased or decreased by 25 percent, the RSP of the advanced dry grind plants and biochemical plants change by approximately two percent, and the RSP of the thermochemical ethanol plants changes by approximately three percent. The sensitivity analysis of capital requirements further supports the fact that the RSP of E85 is dominated by operating costs.

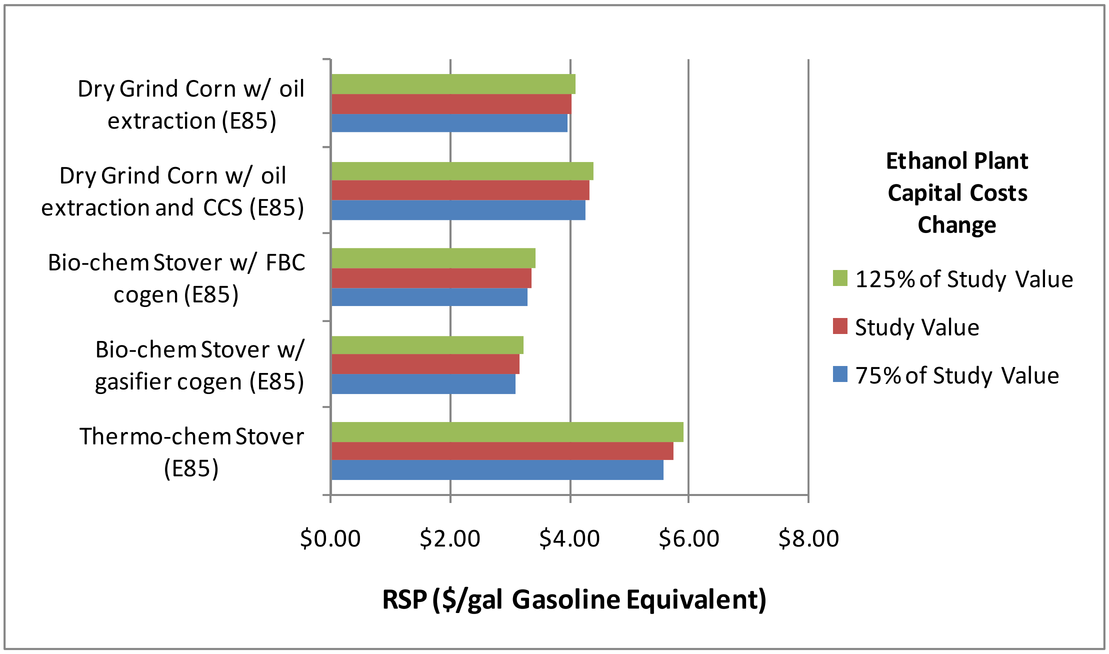

Figure 6-4: LCC Sensitivity of Ethanol Plant Capital Cost

7.0 COMPARISON WITH OTHER LIFE CYCLE STUDIES

NETL's LCA of ethanol is a broad analysis, encompassing three technology categories, three biomass feedstocks, and finished fuels that represent two blending ratios of ethanol and gasoline. This section compares NETL's results with those of similar LCAs.

7.1 Survey of Other LCAs

The scope and boundaries of other LCAs of ethanol are summarized below.

EPA 2009

As a part of the RFS2 program, EPA issued the *Final Regulatory Impact Analysis: Changes to the Renewable Fuel Standard Program* (EPA, 2009a), which includes life cycle models of several renewable fuels, including ethanol. The goal of the document is to standardize the method used for determining the GHG emissions of renewable fuels, which in turn can be used for determining if a particular fuel meets the GHG reduction thresholds as prescribed by the Energy Independence and Security Act of 2007 (EISA). The pathways include corn ethanol from dry grind ethanol plants and ethanol from the biochemical conversion of switchgrass.

The unit processes used by EPA's model account for the energy requirements of renewable fuel production, but results are not presented for energy. The goal of the model is to estimate GHG emissions, and thus other life cycle metrics are not emphasized.

The model assumes that DDGS, a co-product of ethanol, displaces conventional animal feeds made from soy and corn meal. Similarly, it assumes that the electricity that is exported from biochemical ethanol plants displaces electricity produced by utilities.

A key boundary assumption used by EPA's model is the relationships between U.S. agricultural exports and the land use impacts of international agriculture. The GHG results are sensitive to this assumption. In fact, EPA's GHG results for cellulosic ethanol are negative, which could be related to this boundary assumption.

Graboski 2002

In *Fossil Energy Use in the Manufacture of Corn Ethanol* (Graboski, 2002), the author calculates energy ratios for the life cycles of ethanol produced from corn. Scenarios include a 2000 baseline, the average industry from 2002 to 2004, and the projected industry in 2012. The 2012 scenario is the most efficient scenario of this analysis and represents a market mix of 80% dry grind and 20% wet grind ethanol plants. Fossil energy is the only metric that is tracked in this analysis; GHG emissions are not calculated. The model assumes that DDGS displaces conventional animal feeds made from soy and corn meal.

Kammen et al 2008

Energy and Greenhouse Impacts of Biofuels (Kammen *et al.,* 2008) does not represent original LCA work, but is a compilation of the energy and GHG results of existing LCAs. It represents work performed by Pimentel, Patzek, Graboski, Wang, and Shapouri. It shows results only for the production of ethanol from cellulose, and demonstrates that LC results for cellulosic ethanol represent a wide range of results for energy and GHG emissions.

Since Kammen *et al.* account for a wide range of results, the low and high values for GHG emissions and energy use were used to provide data points for comparison with other studies.

Patzek 2004

Thermodynamics of the Corn-Ethanol Biofuel Cycle (Patzek, 2004) estimates the energy and GHG emissions for the cradle-to-grave life cycle of ethanol, based on a theoretical conversion efficiency of a wet mill ethanol plant. No methods are used for co-product management, and thus all environmental burdens of the ethanol plant are assigned to ethanol.

The report does not express cradle-to-grave results on the basis of ethanol production, but includes stage-wise data for corn field production and the ethanol plant. Using the corn yield rates, plant feed rates, and heating values provided by the author, the energy and GHG results were normalized to the life cycle of 1 MJ of ethanol.

Pimentel and Patzek 2005

Ethanol Production Using Corn, Switchgrass, and Wood: Biodiesel Production Using Soybean and Sunflower (Pimentel and Patzek, 2005) is an energy balance of corn and cellulosic ethanol. It focuses on the fossil energy (or, more accurately, the non-renewable energy) expended on the production of ethanol and does not include results for GHG emissions. The scenario for corn ethanol is representative of the wet mill process, and the scenario for cellulosic ethanol is representative of the biochemical conversion of switchgrass.

No attempt is made for system expansion or allocation of burdens between co-products. For wet mill production, ethanol is assigned all burdens of DDGS. The energy and material flows shown for the biochemical conversion of switchgrass do not show any co-products; specifically, no electricity is exported from the cellulosic ethanol plant.

Wang 2001

The GREET Fuel Cycle Model (Wang, 2001) includes energy use and GHG emissions for ethanol produced from corn and cellulosic feedstocks. The fuel consumption data is stratified by three categories: total energy, all fossil fuels, and petroleum only.

The results for ethanol produced from ethanol are a mix of wet and dry grind technologies. The exact mix between these two technologies is not provided in the documentation. The GREET documentation does not clearly define the technology used for the conversion of switchgrass to ethanol, so it is assumed that it is representative of biochemical conversion.

GREET uses system expansion for managing the co-products of ethanol plants. Specifically, DDGS from wet and dry grind ethanol plants is assumed to displace corn and soybean oil used for animal feed, and electricity from cellulosic ethanol plants is assumed to displace grid electricity.

All energy and greenhouse results in the GREET documentation are shown relative to an equivalent energy of RFG (reformulated gasoline). For example, the GHG emissions from the life cycle of 1 MJ of E90 from corn are 29% lower than those for 1 MJ of RFG, and the GHG emissions from the life cycle of 1 MJ of E90 from switchgrass are 78% lower than those for 1 MJ of RFG. According to GREET, RFG has life cycle energy requirements of 5,872 Btu/mile and 469 kg CO_2e/mile (Wang, 2001). These factors were converted to a basis of 1 MJ of fuel using the average fuel economy (24.1 mpg) and relative heating values of RFG and E90; all conversion factors used for this conversion are provided in the GREET documentation (Wang, 2001).

The results of the model are on the basis of E90 (90% ethanol and 10% gasoline). Adequate data are not provided in the GREET documentation to adjust this to a basis of pure ethanol (E100) without disturbing the underlying data and assumptions. This prevents direct comparison between GREET results and other results shown in this appendix

7.2 Comparison

The results of most of the life cycle studies cited here are on the basis of E95. The functional unit of NETL's LCA is life cycle of 1 MJ of E10 or E85 and thus, to improve comparability, the data reviewed here has been converted NETL's results to a basis 1 MJ of E95. As noted above, one exception is the GREET results (Wang, 2001), which are on the basis of E90 and cannot be scaled to the basis of E95 without disturbing the underlying assumptions of the model.

The GHG and non-renewable energy results for the different LCA models are shown in **Table 7-1**. The GHG results represent the cradle-to-grave emissions for 1 MJ of ethanol, and the energy results represent the cradle-to-grave non-renewable energy requirements for 1 MJ of ethanol. **Figure 7-1** and **Figure 7-2** are based on **Table 7-1** and illustrate the range of results demonstrated by the different LCA models. (In the following exhibits, "NETL, 2010" refers to the results of this analysis.)

Table 7-1: Greenhouse Gas Emissions and Energy Results for Ethanol LCAs

Technology	Source	GHG (kg CO_2e/MJ)	Energy (MJ/MJ)
Dry grind (corn)	Patzek, 2004	-	0.714
Dry grind (corn)	Wang, 2001	0.110	0.695
Dry grind (corn)	EPA, 2009	-	1.286
Dry grind (corn)	NETL, 2010	0.066	0.780
Biochemical (switchgrass)	Kammen *et al.*, 2008, low	0.073	-
Biochemical (switchgrass)	Kammen *et al.*, 2008, high	0.065	0.709
Biochemical (switchgrass)	Pimentel & Patzek, 2005	0.065	0.658
Biochemical (switchgrass)	Wang, 2001	0.115	1.128
Biochemical (switchgrass)	EPA, 2009	-	1.450
Biochemical (switchgrass)	NETL, 2010	0.020	0.238

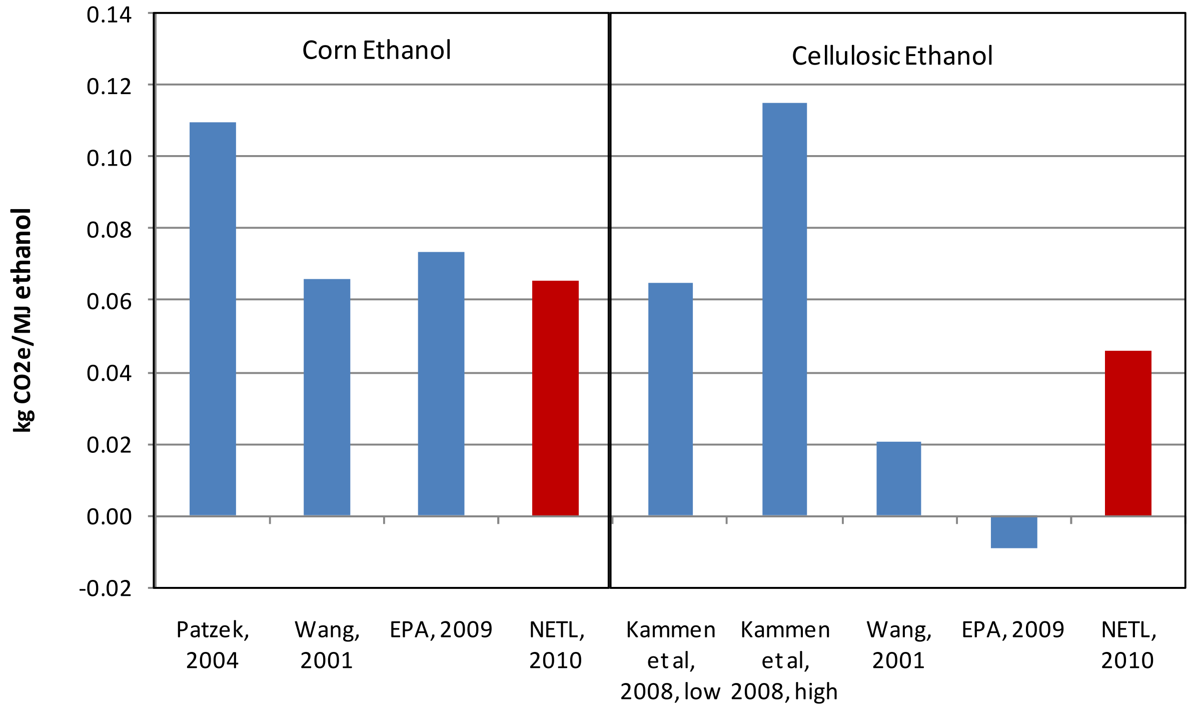

Figure 7-1: Life Cycle Greenhouse Gas Emissions for Ethanol

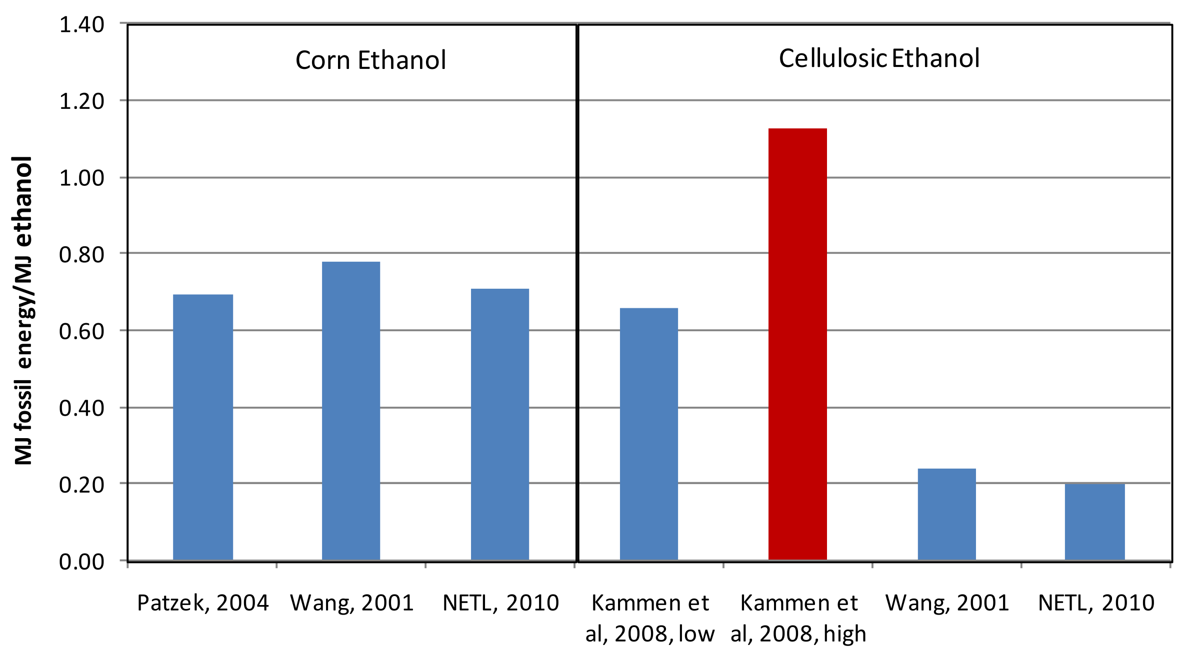

Figure 7-2: Life Cycle Fossil Energy for Ethanol

7.3 Interpretation

NETL's model of ethanol includes a broad list of metrics. In addition to GHG emissions and fossil energy consumption, NETL's results include criteria air pollutants, other air emissions of concern, water consumption, water quality, renewable energy consumption, and land use. The results published in current literature represent GHG emissions and fossil energy consumption, but do not provide results for other metrics.

NETL's model includes a broad array of ethanol production technologies. In addition to conventional dry grind conversion of corn and biochemical conversion of switchgrass, NETL's model includes dry grind ethanol plants that use corn oil extraction technologies, biochemical conversion of corn stover, and thermochemical conversion of switchgrass and corn stover. The other LCA models cited here focus on conventional wet and dry grind conversion of corn and biochemical conversion of switchgrass.

7.3.1 Comparative Greenhouse Gas Results

A comparison of the life cycle GHG emissions shows that NETL's results for corn ethanol are similar to those of GREET (Wang, 2001) and RFS2 (EPA, 2009). NETL, GREET, and RFS2 have similar data sources and use the same method for co-product management. The GHG results of Patzek's model (Patzek, 2004) are higher than other models because it assigns all burdens of DDGS production to ethanol.

There is a broad range in the results for GHG emissions from cellulosic ethanol. NETL's results are higher than those shown by GREET (Wang, 2001) and RFS2 (EPA, 2009). A closer inspection of the data and assumptions of the various models is necessary to determine the reasons for these differences; such an inspection would represent a significant level of effort and is not possible using only the literature cited here. However, the methods for modeling the GHG emissions from land use change, the yield of ethanol per unit biomass feedstock, the mix of fossil fuels and recovered energy used at ethanol plants, and the management of co-produced electricity are likely drivers behind the disparate GHG results for cellulosic ethanol.

7.3.2 Comparative Energy Results

Most models cited here track only the non-renewable energy (i.e., fossil and nuclear energy) associated with the ethanol life cycles. Thus, a comparison of the energy results of all models identified here must focus only on the consumption of non-renewable energy.

A comparison of the life cycle results for energy consumption shows that NETL's results for corn ethanol are similar to those for GREET (Wang, 2001) and Graboski (2002). (Note that the RFS2 results (EPA, 2009) show results only for GHG emissions and not for energy consumption.) NETL, GREET, and Graboski have similar data sources and use the same method for co-product management, which explains why the energy results of these three models are similar. The energy calculated by Pimentel and Patzek (2005) is higher than other models because all burdens of DDGS production are assigned to ethanol.

As was the case for GHG results, there is a broad range in the energy results among different models of cellulosic ethanol. NETL's results are similar to those shown by GREET (Wang, 2001), but are significantly lower than other models cited here. The fact that Pimentel and Patzek (2005) do not credit the system for the export of excess electricity from the biochemical ethanol plants explains, in part, why their results are the highest among all studies cited here.

However, the level of detail provided in the literature is not adequate for identifying other reasons for the disparate results for the life cycle energy of cellulosic ethanol.

8.0 SUMMARY

This analysis includes two models: an environmental LCA model and an LCC analysis. The environmental LCA is a cradle-to-grave inventory of GHGs, CAPs, other air pollutants of interest (e.g., mercury), solid waste, resource energy, water emissions, and water withdrawal. The LCC analysis is a discounted cash flow model that assumes a 30-year study period and accounts for key capital costs and O&M costs from acquisition of raw materials to the delivery of fuel to the consumer. This complete suite of environmental and economic data will allow stakeholders to make informed choices among various alternative fuel options.

This analysis provides a life cycle comparison of three tiers of technology, three types of biomass feedstocks, and two fuel-blending compositions for a total of 18 distinct pathways. The three tiers of technology are the production of ethanol using dry grind technology, biochemical conversion, and thermochemical conversion. The three biomass feedstocks are corn grain, corn stover, and switchgrass. The two fuel-blending compositions are E10 and E85.

The total CO_2e emissions of the ethanol pathways range from 0.021 kg/MJ to 0.096 kg/MJ. The E85 pathway that uses biochemical conversion of corn stover and cogenerates electricity through the gasification of waste biomass has the lowest CO_2e emissions. The relatively low CO_2e emissions of this pathway are due to its high utilization of biomass as both a feedstock and a fuel. The biochemical ethanol plants of this analysis do not purchase fossil fuel-intensive energy (such as electricity or natural gas), but recover process energy from the biomass residuals of the lignocellulosic fermentation process. In fact, the energy recovery systems of the biochemical ethanol plants generate excess electricity that is sold to the electricity grid and, in turn, displaces CO_2e emissions from fossil-intensive power plants.

All E10 pathways fall within a CO_2e emission range of 0.090 kg/MJ and 0.096 kg/MJ. The range of CO_2e emissions for the E10 pathways coincides with the total life cycle emissions of conventional gasoline (0.092 kg CO_2e /MJ) as stated in NETL's baseline LCA of petroleum products (NETL, 2008). The composition of E10 is 90 percent gasoline (by volume), which explains why the CO_2e emissions of the E10 pathways of this analysis are comparable to the gasoline CO_2e emissions from NETL's petroleum baseline.

The CO_2e emissions of the dry grind and biochemical ethanol pathways are affected by the co-products of the ethanol plants. As discussed above, the biochemical ethanol plants sell co-produced electricity, which reduces the net CO_2e emissions of the biochemical ethanol pathways. Similarly, conventional dry grind ethanol plants sell DDGS, and the advanced dry grind plants sell DDGS and corn oil, both of which can displace conventional agricultural materials. The sale of DDGS and corn oil displace the growth of corn (the conventional source for animal feed) and soybeans (the conventional source for biodiesel), respectively.

This analysis also considers the implementation of CCS on an advanced dry grind ethanol plant. Due to the electricity requirements of CO_2 capture and the relatively small share of CO_2 emissions from the ethanol plant (in comparison to CO_2 emissions from the combustion of fuel in a passenger vehicle), CCS does not result in significant reductions in life cycle CO_2 emissions. The conventional dry grind pathway and advanced dry grind pathway have comparable life cycle CO_2e emissions.

CO_2 emissions also result from the transformation of land from one use to another. The switchgrass pathways are the only scenarios of this analysis that demonstrate significant changes in land use because this analysis assumes that switchgrass is grown on sites that were previously unused for agriculture, while corn grain and corn stover are grown on existing agricultural sites. Also, while the construction of ethanol plants and pipelines result in land use changes, such construction activities are overshadowed by the land use changes of switchgrass production.

This analysis tracks the material inputs of all resources as extracted from nature, including petroleum, coal, natural gas, uranium, biomass, and other renewable. The total resource energy of each pathway is determined by factoring each resource input by its heat content. On the basis of 1 MJ of E10 production, the resource energy of the E10 pathways ranges from 1.09 MJ to 1.14 MJ. This narrow range in E10 resource energy is due to the fact that E10 is 90 percent gasoline by volume, and gasoline comes from the same source for all pathways. The resource energies of the E85 pathways are higher than for the E10 pathways. On the basis of 1 MJ of E85 production, the conventional dry grind pathway has the lowest resource energy (1.44 MJ) and the thermochemical switchgrass pathway has the highest resource energy (1.99 MJ). The E85 pathways have higher resource energies than the E10 pathways because in comparison to the petroleum supply chain (which dominates the E10 pathways) ethanol plants have relatively low yields per unit of raw material input. However, while the E85 pathways have higher total resource energies than the E10 pathways, the E10 pathways consume a higher share of fossil resources than the E85 pathways. The average resource profile of the E10 pathways is 88 percent fossil resources, while the average resource profile of the E85 pathways is 33 percent fossil resources.

The results for water consumption represent a wide range: between 4 kg and 130 kg of water per 1 MJ of E10 or E85 production respectively. Water is consumed by all pathways and life cycle stages of this analysis. It is a direct input to biomass growth and ethanol plant operations, and an indirect input to the upstream activities for the production of transportation fuels, electricity, and construction materials. However, the majority of water consumption occurs during the growth of biomass, and thus the E85 pathways, which consume more biomass than the E10 pathways, consume more water than the E10 pathways. Furthermore, switchgrass has the highest water consumptions among the three biomass feedstocks (corn grain, corn stover, and switchgrass) of this analysis. Thus, the E85 pathways that use switchgrass as a feedstock have the highest water consumption of this analysis.

SO_2 emissions result from many activities throughout the life cycles of E10 and E85, including the production of gasoline, the combustion of diesel in farm equipment, the production of fertilizers, and the generation of electricity. These activities are a part of every pathway of this analysis, yet occur in varying proportions. Furthermore, the displacement of electricity from the biochemical ethanol plants results in reductions in SO_2 emissions for the associated pathways. The dry grind pathways for E85 production have the highest SO_2 emissions, while the biochemical pathways have negative net SO_2 emissions.

Other conclusions related to criteria air pollutants and other emissions of concern are as follows:

- The majority of NO_x and CO emissions occur in the final life cycle stage – the combustion of fuel in a passenger vehicle.
- VOCs are significantly higher for the pathways that use corn stover due to the methanol emissions associated with the production of potassium fertilizer that is used to replenish nutrients after corn stover is removed from the field.
- PM_{10} is 58 percent higher for the E85 pathways than for E10 pathways due to the emissions from farm equipment used for biomass production.
- There is a 20 percent difference between the highest and lowest lead emissions of this analysis. The thermochemical pathways have the highest lead emissions because they do not have any co-products that cause the displacement of lead emissions from substitute products.
- Mercury emissions are higher for the E10 pathways than for the E85 pathways because of the relatively higher mercury emissions of the petroleum supply chain in comparison to biomass production.

The results of the LCC analysis demonstrate that the operating costs incurred during the 30-year period of ethanol production overshadow the capital costs for the construction of ethanol plants and fuel distribution infrastructure (pipelines, fuel terminals, and tanker trucks). The LCC analysis calculates the RSP, which is the minimum price at which the fuel should be sold in order to offset O&M and capital costs, taxes, and other debt related to the construction and operation of the fuel cycle.

In this analysis RSP is normalized to the heating value of gasoline, which allows the comparison of E10 and E85 on an equivalent energy basis as well as allowing a fairer comparison between ethanol blends and conventional gasoline. The RSP results for the ethanol blends are normalized to an equivalent heating value of gasoline by factoring the RSP of each ethanol blend by the relative heating values of ethanol and gasoline. A gallon of gasoline has 1.03 times more energy than a gallon of E10 and 1.35 times more energy than a gallon of E85. The RSPs of E10 and E85 are multiplied by these factors in order to normalize them to the same energy basis as conventional gasoline.

A key assumption of this analysis is the cost of corn stover as received by biochemical and thermochemical ethanol plants. The current market value of corn stover is $43.50/ton (USDA, 2008), which includes the costs of collecting stover from the field, applying makeup fertilizer due to the collection of stover, and truck transport of baled stover to an ethanol facility. However, if corn stover transitions from a byproduct of corn production to a commodity for the production of fuels and other products, then its market value will escalate.

Estimations for the cost of corn stover to the entrance of the ethanol plant have been rigorously developed by Idaho National Laboratory (INL 2009[13]). The INL study does not include a grower payment to their calculated feedstock cost. INL reports a feedstock cost close to $72/ton in 2011, with technological advances bringing the cost down to $30/ton by 2017.

In assuming a grower payment, it is important to realize that the first plants will be getting the lowest cost feedstocks with minimal grower payments, and as the industry matures and demand increases, the quality of biomass, and more importantly, land, will rise as will the premium payment to the grower. Combining the two for a delivered feedstock cost, it is assumed that the benefits with process improvements are offset by the increase in grower payment as the industry matures. Therefore, the first payment to the growers is $15/ton, bringing the total feedstock cost for stover to $87/ton. The delivered cost for corn grain is $125.00/ton (USDA, 2008), and the delivered cost for switchgrass is $77.00/ton (NETL, 2009d).

Another important attribute of the LCC analysis is that the majority of costs for the E10 pathways are tracked at the bulk loading terminal (LC Stage #4), while the majority of costs for the E85 pathways are tracked at the ethanol plants (LC Stage #3). Gasoline enters the boundaries of the LCC model at the bulk loading terminal; since E10 has a high proportion of gasoline, the majority of E10 costs are accounted for at the bulk loading terminal. In contrast, the LCC model demonstrates that the majority of ethanol costs occur at ethanol plants; since E85 has a high proportion of ethanol, the majority of E85 costs are attributed to the activities at ethanol plants.

The conventional ethanol dry grind process and the biochemical conversion of cellulose have the lowest RSPs of this analysis, ranging from $3.00 to $3.50 for the quantity of fuel required to deliver the same amount of energy as a gallon of gasoline. The thermochemical pathway that uses corn stover for E85 production has the highest RSP of this analysis ($5.73 per gasoline gallon equivalent).

This analysis focuses on both cost and environmental characteristics of various pathways to ethanol production. The LCC cost analysis demonstrates favorable RSPs for dry grind and biochemical ethanol pathways when costs for E10 and E85 fuel blends are expressed on a gasoline-equivalent energy basis. In most cases, the RSP for E10 is lower than the RSP for E85. The environmental LCA results allow the comparison of several LCI metrics and demonstrate environmental trade-offs between biomass and petroleum supply chains. While ethanol has a favorable greenhouse gas emissions profile, the production of the biomass feedstocks for ethanol production has significant water requirements and results in significant non-greenhouse gas emissions.

[13] Uniform – Format Solid Feedstock Supply System: Hess, Wright, et.al.

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