NATIONAL ENERGY TECHNOLOGY LABORATORY

Life Cycle Analysis: Ethanol from Biomass (Appendices)

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U.S. DEPARTMENT OF ENERGY

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LIFE CYCLE ANALYSIS: ETHANOL FROM BIOMASS (APPENDICES)

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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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APPENDIX A: SUMMARY OF STUDY BOUNDARIES

A.1 Study Boundaries

The environmental boundaries of the study are from cradle-to-grave. All significant operations from raw material acquisition from the earth, energy conversion processes, material transport operations, carbon capture and transport to an undefined site, the storage of liquid transportation fuels, the dispensing of liquid transportation fuels into vehicles, and the operation of the vehicle are accounted for. The boundaries for the LCC do not include the operation of a vehicle. Instead, the LCC ends at the dispenser to the vehicle. All secondary operations that contribute significantly to the mass and energy of the system or the environmental or cost profiles are also included within the study boundary. Examples of secondary operations include, but are not limited to:

- Construction of equipment and infrastructure to support each pathway.
- Production of significant construction materials (e.g., concrete production, steel production, etc.).
- Production of materials applied to maintain process capacities (e.g., fertilizers, herbicides).
- Production of secondary energy resources (e.g., electrical power from the U.S. power grid, diesel fuel, heavy fuel oil).

The scope of the LCC analysis accounts for all significant capital and operating and maintenance (O&M) contributions. "Significant" is defined in relation to the total present value (PV) LCC over the 30-year study period. The goal is to develop "comparable" LCC profiles for each pathway to evaluate the relative difference between pathways. The cost of raw materials is assumed to be inclusive of the purchase price of feedstock materials (biomass) and utilities (e.g., electricity, process water). The LCC analysis calculates both the levelized delivered fuel cost ($\$/gal_{petroleum\ equivalents}$) and net PV for all LC stages.

A.2 Study Geography

Based on the availability of biomass feedstocks and the locations of existing ethanol production facilities, biomass acquisition, ethanol production, and finished fuel (E10 and E85) distribution is assumed to take place in the U.S. Midwest.

The gasoline component of the E10 and E85 fuel blends is assumed to be representative of U.S. average petroleum production, based on NETL's petroleum baseline study (NETL, 2009). This includes a mix of crude oil sourced from foreign and domestic sources and petroleum refined in foreign and U.S. refineries.

A.3 Cut-off Criterion

This analysis uses a one percent cut-off criterion for determining the significance of material and energy flows. This criterion is applied at the unit process level. For example, consider a unit process for the construction of a Class 8b truck, where the reference flow is one truck and the inputs include the materials of construction. If the materials of construction include 100 kg of rubber, but the entire truck weight is 15,000 kg, then the rubber accounts for less than 0.7 percent

of the total mass of the truck, which is below the one percent cut-off criterion. Therefore, it is not necessary to develop unit process data for the modeling of rubber for the construction of a Class 8b truck.

A.4 Processes excluded from the study

The following secondary process functions are excluded from the study:

- Humans involved in the system boundary have a burden on the environment, such as driving to and from work and production of food they eat, that is part of the overall LC. However, this complicates the LC tremendously due to the data collection required to quantify the human-related inflows and outflows on the environment and how to allocate them to fuel production. Furthermore, it is assumed that the workforce will be unaffected by the choice of fuel. Issues related to humans, such as the societal impacts of humans in the workforce that need to be addressed through policy and value-based decisions, are outside the scope of an LC study.
- Low frequency, high-magnitude environmental events (e.g., fugitive or accidental releases) are not included in the system boundaries since such circumstances are difficult to associate with a particular product. More frequent, but perhaps lower magnitude, events such as material loss during the transportation of materials are included in the system boundary.
- Construction emissions are excluded for existing infrastructure that would not need to be replaced in the study period. Existing infrastructure is defined as meeting the following requirements: (1) in existence on the start date of the study (January 1, 2012) and (2) lifetime exceeds the length of the study period (30 years). Existing infrastructure in this study includes a bulk refueling facility and a vehicle refueling station. It is noted that emissions from maintenance or upgrading of the facilities is included, where necessary, in the study.

APPENDIX B: DETAILED ASSUMPTIONS FOR ETHANOL LC STAGES

B.1 Life Cycle Stage #1: Biomass Production

This analysis includes three types of biomass: corn grain, corn stover, and switchgrass. The data used for the production of these three biomass feedstocks are detailed below.

B.1.1 Corn Grain and Corn Stover Production

Corn grain is a valuable food crop that can also be used for the production of fuels such as ethanol. Corn stover is the residue from corn harvesting and includes stalks, leaves, and cobs. Differences between the production requirements of the two co-products are noted when appropriate.

Corn grain includes starch, which is a glucose polymer that can be easily broken down to glucose monomers and fermented to ethanol (Aden *et al*., 2002). The composition of corn grain is shown in **Table B-1.**

Table B-1: Corn Grain Physical Properties

Physical Component/Property	Value	Source
Starch (%)	72.0	Aden *et al*., 2002
Hemicellulose/Cellulose (%)	10.5	Aden *et al*., 2002
Protein (%)	9.5	Aden *et al*., 2002
Oil (%)	4.5	Aden *et al*., 2002
Sugars (%)	2.0	Aden *et al*., 2002
Ash (%)	1.5	Aden *et al*., 2002
Carbon (%)	45.0	Watson and Ramstad,1987
LHV at 15% Moisture (Btu/lb)	6,480 – 6,810	Pimentel and Patzek, 2005; PSU, 2009

Corn stover is a cellulosic material and, if left in the field after corn harvesting, degrades and provides valuable nutrients to the soil. Alternatively, corn stover can be collected from the field and used as a feedstock for the production of liquid fuels. The composition and energy density of corn stover as given by the NETL Biomass Model (NETL, 2009c) are shown in

Table B-2**.** This analysis uses a corn stover yield rate of 4.25 tons/acre-yr of corn stover, which requires that 70 percent of the stover is removed from the field, while the remaining 30 percent of the stover residue is necessary to prevent erosion of the field (Brechbill, 2008).

Table B-2: Corn Stover Physical Properties (NETL, 2009c)

Physical Component/Property	Value
Ash (%)	9.82 – 13.5
Carbon (%)	44.7 – 48.0

Hydrogen (%)	5.41 – 6.14
Nitrogen (%)	0.59 – 0.74
Oxygen (%)	37.0 – 41.4
Sulfur (%)	0.06 – 0.10
HHV Moisture Free (Btu/lb)	7,700 – 7,970
LHV Moisture Free (Btu/lb)	7,200 – 7,470
Na_2O (% composition of ash)	1.47
K_2O (% composition of ash)	20.2
Ash Fusion Temperature (°C)	884 (reducing atmosphere) 1,050 (oxidizing atmosphere)

Figure B-1 shows the LC boundaries of corn stover production. LC Stage #1 includes activities associated with land preparation, cultivation and maintenance, harvesting, and biomass preparation for transport in LC Stage #2.

The LC boundary of corn grain and stover production starts with the extraction of natural resources and ends with corn grain and stover ready for delivery to the fuel production facility. **Figure B-1** also shows the sequence of unit processes and the flows of raw materials among unit processes. All unit processes require energy, but for the purposes of this discussion the figure does not show fuel-related flows other than diesel use for operations processes. The figure includes processes directly related to the growing and harvesting of corn and corn stover, as well as upstream processes that account for fertilizer production, farming equipment, land, water, and other agricultural inputs.

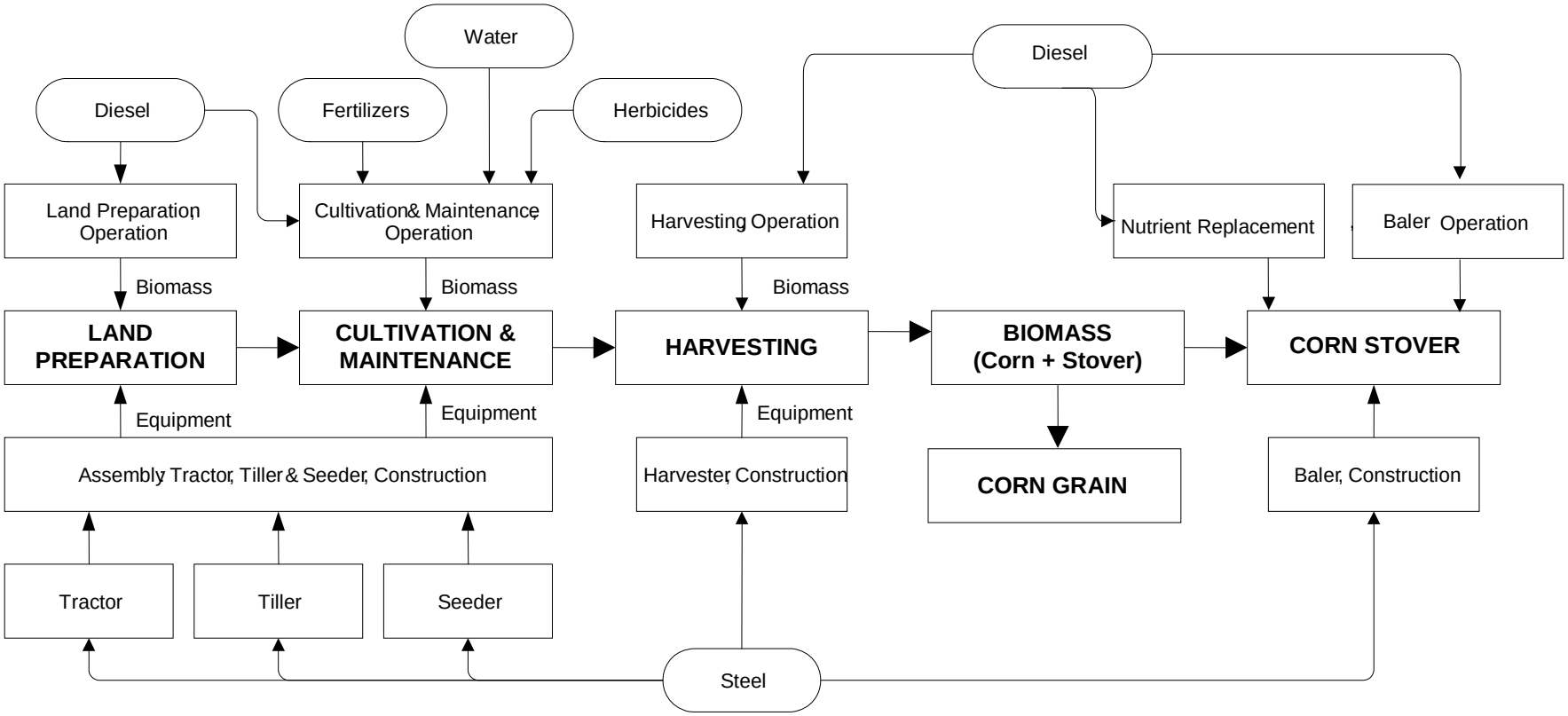

Figure B-1: Corn Grain and Stover Production Processes

Corn grain and corn stover are co-products of the majority of processes shown in **Figure B-1**. It is necessary to partition the resources and emissions of corn growing processes between stover and grain. This analysis applies an energy-based allocation method between corn grain and stover. The percent of resources and emissions allocated to each product is determined by their relative calorific values (in MJ/kg) factored by their relative yields (in kg/acre). Using energy as a basis for the co-product allocation between corn grain and stover, 59 percent of the shared process emissions are allocated to stover and 41 percent are allocated to grain. (More details on the co-product allocation calculation are shown in **Appendix E**.) If mass-based allocation is used, 56 percent of resources and emissions are allocated to stover and 44 percent to grain.

Figure B-2 shows the boundary for processes shared by corn stover and corn grain. Both products share emissions due to land preparation, cultivation, and harvesting of corn grain, as well as all sub-processes for these primary processes. Additional fertilizer and corn stover collection are attributed to the stover alone.

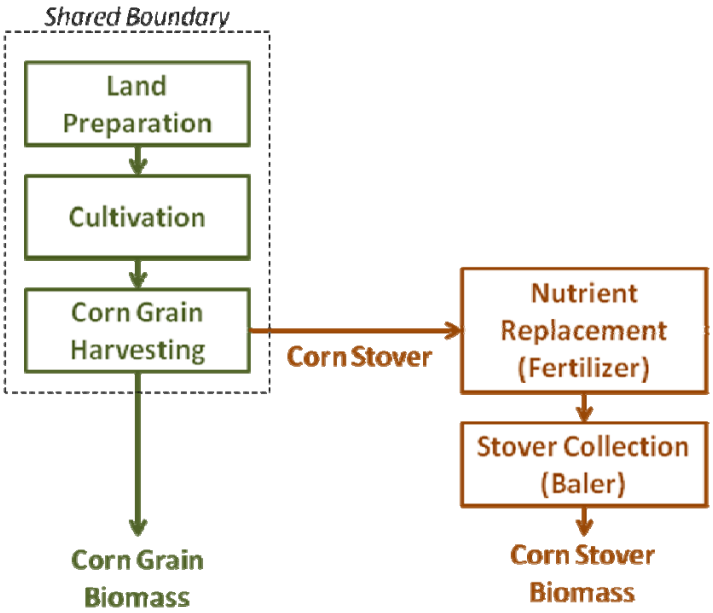

Figure B-2: Corn Stover and Corn Grain Biomass Shared Boundary and Allocation Application

Options for soil maintenance during a growing cycle include conventional tilling and no-till practices. Conventional tilling involves aggressive mechanical turnover of soil (i.e., plowing), while no-till practices leave the soil bed intact (Sheehan, 2004). The disadvantages of conventional tilling are a high loss of soil organic matter and erosion from wind and rain (Sheehan, 2004). An advantage of no-till practices is a reduction in fertilizer use due to retention of organic matter (Sheehan, 2004); however, a disadvantage of no-till practices is an increased use of herbicides (Kim, 2005a). Due to the prevalence of conventional tilling practices currently and into the foreseeable future, conventional tilling is assumed to be utilized exclusively as the base-case scenario for this study.

The rotation scenario for a crop also affects the energy and material flows for growing corn. Rotation scenarios include continuous corn crops, corn/soybean rotation crops, and continuous corn crops with winter cover crops. There are advantages and disadvantages for each rotation method, including different fertilizer application rates and different yields of corn and corn

stover. Continuous corn crops grow corn every growing season, so no transition from one crop to another is required between growing seasons. Corn/soybean rotation crops are alternated between corn and soybeans each growing season, which allows a lower application rate of nitrogen fertilizer (Kim, 2005b) due to the nitrogen fixation from soybean growth. When winter cover crops are planted, it compensates for the loss of nutrient biomass caused by stover removal (Kim, 2005b). Since continuous corn crops are the conventional, most-practiced method for the rotation of corn crops, this analysis assumes continuous corn crop rotation for corn grain and stover production (Sheehan et al, 2004).

Table B-3 provides a summary of the key assumptions included in the LC Stage #1 model for corn stover production.

Table B-3: Key Assumptions for Corn Grain and Stover Environmental Model

Pathway Sector	Assumption	Basis
Cultivation and Maintenance	**Fertilizer Application Emissions**: It is assumed that 10 percent by weight of applied nitrogen fertilizer volatilizes. Of that volatized nitrogen fertilizer, it is further assumed that one percent reacts to form N_2O. Of the 90 percent of nitrogen fertilizer that does not volatize, soil processes release 0.0125 tons of N_2O per ton of nitrogen. An estimated 30 percent of non-volatized nitrogen is assumed to leach or runoff, forming 0.025 tons of N_2O per ton of nitrogen in leachate or runoff.	Ney and Schnoor, 2002
Cultivation and Maintenance	**Water Application:** It is assumed that water is applied via rainfall, with irrigation used to supplement rainfall, at rates indicated by relevant literature sources. Applied water would include rainfall, as well as irrigation water. Irrigation water would be comprised of 50 percent surface water and 50 percent groundwater.	Present Study
Cultivation and Maintenance	**Lime Application Emissions**: Application of lime results in secondary emission of large amounts of CO_2 from production using limestone ($CaCO_3$). Application rates for lime are taken from an ANL study on biomass production pathways.	Wu, 2006
Cultivation and Maintenance	**Cultivation Period:** Continuous growth of corn is assumed, with annual harvesting at which time the full crop is depleted and replanted the following year.	Present Study
Cultivation and Maintenance	**Tilling Practices:** Conventional tilling practices, as opposed to conservation tillage or no-till, are assumed.	Present Study
General	**Transportation Distance:** The corn stover feedstock would be grown within a 30 to 50 mile collection radius of the BTL plant.	Present Study
Harvesting	**Feedstock Drying:** During harvesting, corn stover is cut and separated from corn grain, and allowed to dry in the field to a moisture content of 15 percent prior to collection, baling, storage, and transport during LC Stage #2. 70 percent of the available stover residue is collected.	Present Study; Brechbill *et al.* (2008)
Land Preparation	**Land Type:** Corn stover would be grown on existing farmlands that had been previously used for other agricultural crops.	Present Study
Land Preparation	**Land Preparation:** Existing farmlands would require only minimal preparation prior to the initiation of corn stover production. Lands having existing forest or other intact natural habitat are not included as potential corn stover production areas.	Present Study
Collection Area	**Collection Area:** The data for the production of corn grain and stover is normalized to 1 kg of production and does not account for the required collection area to support an ethanol plant. However, the required size of a collection area is accounted for in the transportation calculations for LC	Present Study

Pathway Sector	Assumption	Basis
	Stage #2	

The following tables show the LCI results for the production of one kilogram of corn grain and corn stover. These results are provided in terms of one kilogram of grain or stover ready for transport. The following results are independent of the fuel production pathway for the two ethanol blends (E10 and E85). Further, the following results are on a mass basis, so comparisons among feedstocks (including corn grain, corn stover, and switchgrass) should be made only after accounting for the unique energy content of each feedstock.

Due to CO_2 uptake during the growth of the corn plant, the net CO_2 emissions from corn grain and stover production have a negative value, as can be seen in **Table B-4**. The quantity of absorbed CO_2 is calculated from the carbon content of each biomass type as shown in **Table B-1** and

Table B-2. Some LCAs do not inventory this CO_2; rather, it is assumed that any CO_2 emissions from combustion of biomass are reabsorbed by an equivalent quantity of biomass, resulting in a carbon neutral process. This study prefers to inventory carbon uptake in LC Stage #1 and emission in LC Stage #3 and Stage #5 in order to more explicitly model the LC Stages. Theoretically, the net results of both methods are equivalent.

Table B-4: Air Emissions from LC Stage #1 Corn Grain and Stover Production

		Corn Grain	Corn Stover	Units (per kg product)
GHG	CO_2	1.32E-01	1.29E-01	kg CO_2e
	CO_2 biomass uptake	-1.49E+00	-1.62E+00	kg CO_2e
	CH_4	3.86E-03	3.73E-03	kg CO_2e
	N_2O	2.31E-01	2.02E-01	kg CO_2e
	Total	-1.12	-1.82	kg CO_2e
CAPs	NO_X	3.43E-04	3.35E-04	kg
	SO_2	1.51E-04	1.54E-04	kg
	CO	2.25E-04	2.09E-04	kg
	VOC	7.57E-06	7.55E-06	kg
	PM	1.26E-03	6.19E-04	kg
	Lead	7.75E-09	8.12E-09	kg
Species of Interest	Mercury	6.63E-10	6.81E-10	kg
	Ammonia	1.31E-04	1.28E-04	kg
	HCl	2.18E-06	2.40E-06	kg
	HF	4.43E-08	4.28E-08	kg
	NMVOC	4.00E-02	5.90E-02	kg

Table B-5: Emissions to Water and Water Withdrawal for LC Stage #1 Corn Grain and Stover Production

		Corn Grain	Corn Stover	Units (per kg product)
Emissions to Fresh Water	Aluminum	1.08E-07	1.04E-07	kg
	Ammonia	1.01E-07	1.08E-07	kg
	Hydrofluoric acid	6.01E-12	5.74E-12	kg
	Hydrogen chloride	2.37E-12	2.29E-12	kg
	Iron	1.59E-05	1.54E-05	kg
	Nitrate	5.71E-07	5.52E-07	kg
	Nitrogen	8.64E-05	5.38E-05	kg
	Phosphate	6.50E-08	6.25E-08	kg
	Phosphorus	1.37E-04	1.13E-04	kg
Emissions to Sea Water	Arsenic (+V)	9.54E-10	9.06E-10	kg
	Cadmium (+II)	5.93E-10	5.66E-10	kg
	Chromium (unspec.)	1.49E-09	1.42E-09	kg
	Copper (+II)	2.31E-09	2.21E-09	kg
	Iron	7.61E-09	6.89E-09	kg
	Lead (+II)	5.33E-10	5.10E-10	kg
	Manganese (+II)	7.88E-10	7.14E-10	kg
	Nickel (+II)	9.63E-10	9.06E-10	kg
	Strontium	2.28E-08	2.20E-08	kg
	Zinc (+II)	1.04E-08	9.35E-09	kg
	Aluminum (+III)	1.10E-10	1.06E-10	kg
	Ammonia	3.26E-09	3.15E-09	kg
	Nitrate	2.12E-09	1.94E-09	kg
Water Withdrawal	Water in	3.25E-01	1.36E-01	m^3
	Water	3.40E-08	1.91E-08	m^3
	Water (feed water)	0.00E+00	0.00E+00	m^3
	Water (ground water)	7.22E-03	3.02E-03	m^3
	Water (river water)	0.00E+00	0.00E+00	m^3
	Water (storm)	3.11E-01	1.30E-01	m^3
	Water (surface water)	7.24E-03	3.03E-03	m^3
	Water (well water)	0.00E+00	0.00E+00	m^3
	Water (with river silt)	4.23E-18	2.37E-18	m^3
	Water Out	9.97E-03	4.17E-03	m^3
	Water (river water)	9.02E-05	5.08E-05	m^3
	Water (sea water)	0.00E+00	0.00E+00	m^3
	Water (secondary)	0.00E+00	0.00E+00	m^3
	Water (storm runoff)	9.88E-03	4.12E-03	m^3
	Net	3.15E-01	1.32E-01	m^3

Table B-6: Solid Waste from LC Stage #1 Corn Grain and Stover Production

		Corn Grain	Corn Stover	Units (per kg product)
Heavy metals to agricultural soil	Cadmium (+II)	2.64E-05	3.29E-07	kg
	Chromium (unspecified)	3.96E-07	1.57E-05	kg
	Copper (+II)	1.90E-05	8.83E-07	kg
	Lead (+II)	9.86E-07	1.63E-07	kg
	Mercury (+II)	1.71E-07	2.61E-09	kg
	Nickel (+II)	2.31E-09	5.29E-07	kg
	Zinc (+II)	5.80E-07	4.84E-06	kg
Heavy metals to industrial soil	Cadmium (+II)	8.66E-07	9.14E-12	kg
	Chromium (+III)	9.56E-12	2.11E-14	kg
	Lead (+II)	2.19E-14	6.82E-13	kg
	Mercury (+II)	7.13E-13	4.96E-14	kg
	Strontium	5.19E-14	8.20E-07	kg
Waste Flow	Slag and Ashes from Energy Production	6.90E-09	6.73E-09	kg
	Slag and Ashes from Waste Incineration	1.96E-08	1.92E-08	kg
	Slag Containing Manganese	1.38E-12	1.34E-12	kg
	Unspecified Furnace Slag	1.22E-08	1.19E-08	kg

Table B-7: Energy Containing Materials for LC Stage #1 Corn Grain and Stover Production

		Corn Grain	Corn Stover	Units (per kg product)
Energy Containing Material Inputs	Crude oil	3.41E-01	3.20E-01	MJ
	Hard coal	1.18E-01	1.17E-01	MJ
	Lignite	4.43E-02	4.27E-02	MJ
	Natural gas	7.22E-01	7.01E-01	MJ
	Uranium	8.94E-02	8.64E-02	MJ
	Corn Grain	1.55E+01	0	MJ
	Corn Stover	0	1.71E+01	MJ
	Others (renewables)	9.32E-02	8.98E-03	MJ
	Total	166	184	MJ

B.1.2 Switchgrass Production

Switchgrass (*Panicum virgatum*) is a perennial grass that is native to the U.S. plain states, as well as portions of Mexico and Canada. Prior to European settlement and the widespread development of present-day farming practices, the grass was a common species in the North American tall grass prairie. Switchgrass still grows naturally in remnant habitats, and can also be found along roadsides and other fallow areas within its natural range. As a biomass crop, switchgrass is tolerant of many soil types and can potentially be grown on existing productive or

degraded farmland, or on other degraded lands such as depleted or marginal farmland, decommissioned coal mines, polluted land, and other marginal lands.

Substantial research has focused on the use of switchgrass as a source of biomass to produce renewable electricity and fuels, including development of variants that are specifically well suited for use as an energy source. Switchgrass provides a cellulosic feedstock that can be used to produce heat and electricity, or converted into ethanol, F-T liquids, or other renewable fuels. The composition and energy density of switchgrass as given by an internal NETL Biomass Model (NETL, 2009c) are shown in **Table B-8**.

The LC boundary of switchgrass production is shown in **Figure B-3**. LC Stage #1 includes activities associated with land preparation, cultivation and maintenance, harvesting, and biomass preparation for transport during LC Stage #2. The LC boundary of switchgrass production starts with the extraction of natural resources and ends with switchgrass ready for delivery to the fuel production facility. The figure also shows the sequence of unit processes and the flows of raw materials between unit processes. All unit processes require energy, but for the purposes of this discussion the figure does not show fuel-related flows other than diesel use for operations processes.

Table B-8: Switchgrass Physical Properties (NETL, 2009c)

Physical Component/Property	Value
Ash (%)	4.54 – 7.55
Carbon (%)	45.4 – 48.5
Hydrogen (%)	5.31 – 6.12
Nitrogen (%)	0.44 – 1.27
Oxygen (%)	38.2 – 42.1
Sulfur (%)	0.07 – 0.11
HHV Moisture Free (Btu/lb)	7,890 – 8,230
LHV Moisture Free (Btu/lb)	7,430 – 7,700
Na_2O (% composition of ash)	0.55
K_2O (% composition of ash)	13.9
Ash Fusion Temperature (°C)	1020

It can be seen in **Figure B-3** that the switchgrass model distinguishes three major activities for biomass production: land preparation, cultivation and maintenance, and harvesting. Land preparation for switchgrass requires the use of a bulldozer and motor grader to prepare marginal lands for cultivation. These pieces of equipment are constructed of steel and operated using diesel. Cultivation and maintenance includes the annual application of fertilizers, herbicides, irrigation, and the planting of seed using a seeder. The harvesting process includes cutting and baling of switchgrass, as well as collection of bales for storage before transport to the plant. Detailed descriptions on the key assumptions made to develop the switchgrass production process are provided in **Table B-9**.

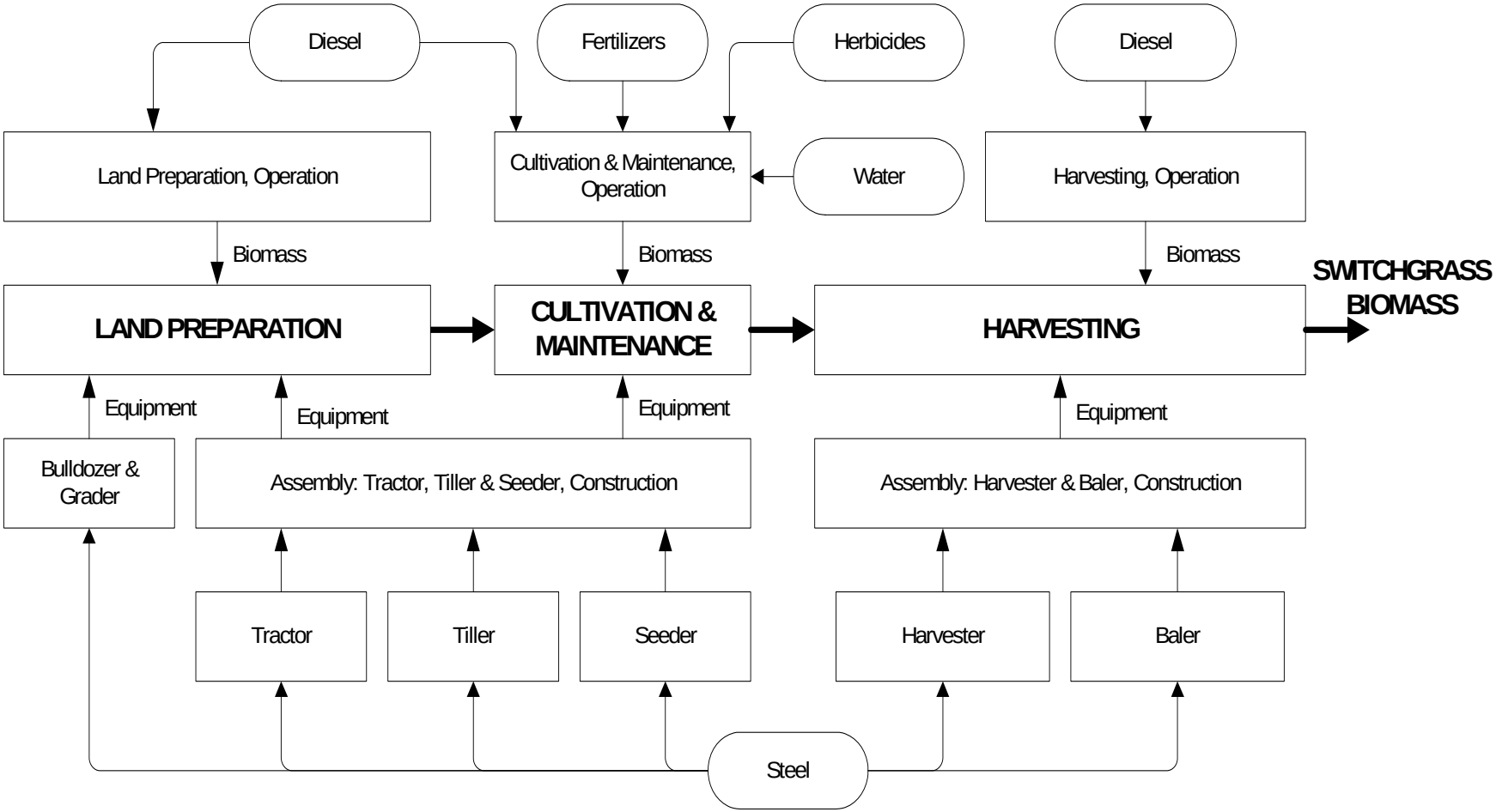

Figure B-3: Switchgrass Production Processes

Table B-9: Key Assumptions for Switchgrass Production Environmental Model

Pathway Sector	Assumption	Basis
Cultivation and Maintenance	**Fertilizer Application Emissions**: It is assumed that 10 percent by weight of applied nitrogen fertilizer volatilizes. Of that volatized nitrogen fertilizer, it is further assumed that one percent reacts to form N_2O. Of the 90 percent of nitrogen fertilizer that does not volatize, soil processes release 0.0125 tons of N_2O per ton of nitrogen. An estimated 30 percent of non-volatized nitrogen is assumed to leach or runoff, forming 0.025 tons of N_2O per ton of nitrogen in leachate or runoff.	Ney and Schnoor, 2002
Cultivation and Maintenance	**Lime Application Emissions:** Lime application is not required for switchgrass production.	Pimentel and Patzek, 2005
Cultivation and Maintenance	**Cultivation Period:** It is assumed that switchgrass requires one year to mature prior to harvesting, which is in line with the majority of previous studies (some indicate two years prior to maturity). It is assumed that mowing and collection of switchgrass would occur during the first year, but that yields would be reduced (30 percent per year) in subsequent years. Additionally, fertilizer and herbicide rates differ between the first and following years.	Ney and Schnoor, 2002
Cultivation and Maintenance	**Water Application:** It is assumed that water is applied via rainfall, with irrigation used to supplement rainfall, at rates indicated by relevant literature sources. Irrigation water is comprised of 50 percent groundwater and 50 percent surface water. All water inputs and outputs are tracked, as relevant. Applied water includes rainfall as well as irrigation water.	Brown *et al*., 2000
General	**Transportation Distance:** Biomass feedstock is grown within a 30-50 mile collection radius of the ethanol plant.	NETL, 2009d
Harvesting	**Feedstock Drying:** During harvesting, switchgrass is cut and allowed to dry in the field to a moisture content of 15 percent prior to collection, baling, storage, and transport.	NETL, 2009d
Land Preparation	**Land Type:** Switchgrass is assumed to be grown on existing marginal lands that do not contain quality natural habitat. Marginal lands could include degraded or marginal farmland, retired mineral extraction sites, and other marginal lands.	NETL, 2009d
Land Preparation	**Land Preparation:** Marginal lands require site preparation (grading) prior to the initiation of agricultural activities. Lands having existing forest or other intact natural habitat are not included as potential switchgrass production areas.	Present Study
Land Use	**Land Use:** No land use changes would occur as a result of biomass cultivation, and switchgrass is cultivated only on marginal lands not suitable for food-crops (abandoned mine lands, etc.) or depleted croplands. This can result in a relatively large collection area for a small amount of biomass, as only a fraction of the land in proximity to the plant is considered to be marginal and available for energy crop cultivation.	NETL, 2009d
Collection area	**Collection Area:** The data for the production of switchgrass is normalized to 1 kg of production and does not account for the required collection area to support an ethanol plant. However, the required size of a collection area is accounted for in the transportation calculations for LC Stage #2**.**	Present Study

The environmental profile for switchgrass production is shown in the following tables. These results are expressed on the basis of one kilogram of switchgrass produced in LC Stage #1 and

ready for subsequent transport to an ethanol plant. The following results are independent of the fuel production pathway for ethanol blends (E10 and E85). Further, the following results are on a mass basis and thus comparisons among feedstocks (including corn grain, corn stover, and switchgrass) should be made only after accounting for the unique energy content of each feedstock.

Due to CO_2 uptake during the growth of switchgrass, the net CO_2 emissions from switchgrass production have a negative value, as can be seen in **Table B-10**. The quantity of absorbed CO_2 is calculated from the carbon content of switchgrass.

Table B-10: Air Emissions from LC Stage #1 Switchgrass Production

		Switchgrass	Units (per kg product)
GHG	CO_2	1.58E-01	kg CO_2e
	CO_2 biomass uptake	-1.54E+00	kg CO_2e
	CH4	4.71E-03	kg CO_2e
	N2O	3.02E-01	kg CO_2e
	Total	-1.08	kg CO_2e
CAPs	NOX	4.26E-04	kg
	SO2	2.22E-04	kg
	CO	1.74E-04	kg
	VOC	8.00E-06	kg
	PM	4.29E-05	kg
	Lead	8.40E-09	kg
Species of Interest	Mercury	7.25E-10	kg
	Ammonia	1.71E-04	kg
	HCl	1.96E-06	kg
	HF	4.63E-08	kg
	NMVOC	1.97E-06	kg

Table B-11: Emissions to Water and Water Withdrawal for LC Stage #1 Switchgrass Production

		Switchgrass	Units
Emissions to Fresh Water	Aluminum	1.21E-07	kg
	Ammonia	1.09E-07	kg
	Hydrofluoric acid	7.30E-12	kg
	Hydrogen chloride	2.86E-12	kg
	Iron	1.65E-05	kg
	Nitrate	6.49E-07	kg
	Nitrogen	2.08E-05	kg
	Phosphate	8.09E-08	kg
	Phosphorus	8.00E-05	kg
Emissions to Sea Water	Arsenic (+V)	1.06E-09	kg
	Cadmium (+II)	6.63E-10	kg
	Chromium (unspecified)	1.65E-09	kg
	Copper (+II)	2.63E-09	kg
	Iron	7.09E-09	kg
	Lead (+II)	6.09E-10	kg
	Manganese (+II)	7.34E-10	kg
	Nickel (+II)	1.04E-09	kg
	Strontium	2.65E-08	kg
	Zinc (+II)	9.30E-09	kg
	Aluminum (+III)	1.28E-10	kg
	Ammonia	3.80E-09	kg
	Nitrate	2.04E-09	kg
Water Withdrawal	Water in	1,130	m^3
	Water (unspecified)	7.54E-05	m^3
	Water (ground water)	112	m^3
	Water (storm)	909	m^3
	Water (surface water)	112	m^3
	Water (with river silt)	9.88E-15	m^3
	Water Out	29.1	m^3
	Water (river water)	1.92E-01	m^3
	Water (storm runoff)	289	m^3
	Net	1,100	m^3

Table B-12: Solid Waste from LC Stage #1 Switchgrass Production

		Switchgrass	Units (per kg product)
Heavy Metals to Agricultural Soil	Cadmium (+II)	2.42E-07	kg
	Chromium (unspecified)	1.13E-05	kg
	Copper (+II)	7.65E-07	kg
	Lead (+II)	1.45E-07	kg
	Mercury (+II)	1.38E-09	kg
	Nickel (+II)	4.95E-07	kg
	Zinc (+II)	4.39E-06	kg
Heavy Metals to Industrial Soil	Cadmium (+II)	1.16E-11	kg
	Chromium (+III)	2.63E-14	kg
	Lead (+II)	8.66E-13	kg
	Mercury (+II)	6.31E-14	kg
	Strontium	1.04E-06	kg
Waste Flow	Slag and Ashes from Energy Production	6.03E-09	kg
	Slag and Ashes from Waste Incineration	1.72E-08	kg
	Slag Containing Manganese	1.20E-12	kg
	Unspecified Furnace Slag	1.06E-08	kg

Table B-13: Energy Containing Materials for LC Stage #1 Switchgrass Production

		Switchgrass	Units (per kg product)
Energy Inputs	Crude oil	3.60E-01	MJ
	Hard coal	1.23E-01	MJ
	Lignite	5.37E-02	MJ
	Natural gas	1.79	MJ
	Uranium	1.01E-01	MJ
	Switchgrass	17.6	MJ
	Others (renewables)	8.98E-03	MJ
	Total	20.0	MJ

B.2 Life Cycle Stage #2: Biomass Transport

The boundaries of LC Stage #2 begin with the loading of biomass onto truck at the growing site and end with the delivery of biomass to the ethanol plant. All biomass (corn grain, corn stover, and switchgrass) is assumed to be transported by truck from the growing site of LC Stage #1 to the ethanol plant of LC Stage #3.

The transportation distance from farm to ethanol production facility is based on the feedstock input to each ethanol plant, the biomass yield per acre of a farm, assumed energy crop intensity, and the likely transportation path of the trucks used for biomass transport.

The energy crop intensity is calculated by assuming that half of the available cropland in Iowa and Nebraska are used for energy crops. The percentage of total land area devoted to cropland in Iowa and Nebraska is 59 percent (USDA, 2009a and 2009b), resulting in an energy crop intensity of 28 percent.

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 the following equation,

$$d = r \sin \theta + r \cos \theta \qquad \textbf{(Equation B-1)}$$

The calculation of biomass transportation distances in LC Stage #2 is demonstrated in **Table B-14**. The one-way transportation distances for the transport of biomass from the farm to ethanol plant are from 21 miles, 23 miles, and 31 miles for corn grain, corn stover, and switchgrass, respectively. This analysis assumes that trucks are dedicated to the transport of biomass between farm and ethanol plant, and thus make a round trip. The round trip distance is calculated by doubling the one-way trip distance.

This analysis assumes that the fuel efficiency of trucks used for biomass transport does not change significantly when making an empty return trip. It is likely that 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 of road transport. A sensitivity analysis on the transportation distance of LC Stage #2 was conducted to determine if an overstatement of transportation requirements has a significant effect on total LC results.

Table B-14: Biomass Transport Distance Parameters

Variable	Units	Dry Grind Corn	Biochem Stover	Biochem Switchgrass	Thermochem Stover	Thermochem Switchgrass
Plant feedrate, daily	ton/day	1,400	2,100	2,400	2,160	2,300
Plant feedrate at 85% capacity, annual	kg/yr	394,000,000	592,000,000	676,000,000	608,000,000	648,000,000
Farm yield rate	kg/acre-yr	2,980	3,856	2,430	3,856	2,430
Area of required cropland[1]	Acre	132,000	154,000	278,000	158,000	267,000
	mi^2	206	241	434	247	417
Energy crop intensity[2]	%	29%	29%	29%	29%	29%
Region to support ethanol plant[3]	mi^2	703	820	1,480	842	1,420
Radius of collection[4]	mi	15	16	22	16	21
Transport distance (one way)[5]	mi	21	23	31	23	30
Transport distance (round trip)[6]	mi	42	46	61	46	60

[1]Area of required cropland is calculated by dividing annual plant federate by the farm yield rate. 1 square mile = 640 acres.

[2]The energy crop intensity is the assumed land area within the region of the ethanol plant that is used for energy crops. It is calculated by assuming that half of the cropland in Iowa and Nebraska are used for energy crops.

[3]The region to support each ethanol plant is calculated by factoring the yield of each biomass with the planting intensity.

[4]The transport radius is calculated by assuming a circle with an area equal to the required land area.

[5]The transport distance (one way) is calculated using Equation 8, assuming an angle of 45 degrees.

[6]The transport distance (round trip) is calculated by doubling the one-way distance.

The following tables (**Table B-15** through **Table B-18**) show the LC stage environmental profiles for biomass transport.

Table B-15: Air Emissions from LC Stage #2 Biomass Transport for the Production of Ethanol

		Corn Grain	Corn Stover	Switchgrass	Units (per kg biomass)
GHG	CO_2	2.56E-03	4.69E-03	5.97E-03	kg CO_2e
	CH_4	2.14E-04	4.30E-04	5.51E-04	kg CO_2e
	N_2O	1.87E-05	3.41E-05	4.27E-05	kg CO_2e
	Total	2.79E-03	5.16E-03	6.57E-03	kg CO_2e
CAPs	NO_X	3.31E-06	5.72E-06	7.25E-06	kg
	SO_2	5.50E-06	7.37E-06	9.24E-06	kg
	CO	8.40E-06	1.09E-05	1.34E-05	kg
	VOC	1.48E-06	3.10E-06	4.00E-06	kg
	PM	8.75E-07	4.21E-07	4.89E-07	kg
	Lead	5.18E-10	6.31E-10	6.52E-10	kg
Species of Interest	Mercury	3.00E-11	3.68E-11	3.86E-11	kg
	Ammonia	1.27E-08	1.77E-08	2.08E-08	kg
	HCl	3.10E-08	2.22E-08	2.39E-08	kg
	HF	2.22E-08	4.28E-09	4.61E-09	kg
	NMVOC	1.48E-06	3.10E-06	4.00E-06	kg

Table B-16: Emissions to Water and Water Withdrawal for LC Stage #2 for Biomass Transport for the Production of Ethanol

		Corn Grain	Corn Stover	Switchgrass	Units (per kg biomass)
Emissions to Water	Aluminum	2.52E-09	1.90E-09	2.34E-09	kg
	Ammonia	2.22E-08	2.93E-08	3.24E-08	kg
	Heavy Metals	2.16E-07	2.88E-07	3.65E-07	kg
	HCl	2.51E-13	5.22E-13	6.78E-13	kg
	Nitrate	1.82E-07	1.92E-07	1.94E-07	kg
	Nitrogen	8.27E-09	8.70E-09	8.70E-09	kg
	Phosphate	6.23E-09	6.99E-09	7.13E-09	kg
	Phosphorus	1.10E-09	2.11E-09	2.68E-09	kg
Water Withdrawal	Water in	8.70E-09	9.65E-09	1.21E-08	m^3
	Water Out	1.41E-09	1.49E-09	2.49E-09	m^3
	Net	7.30E-09	8.17E-09	9.60E-09	m^3

Table B-17: Solid Waste from LC Stage #2 for Biomass Transport for the Production of Ethanol

		Corn Grain	Corn Stover	Switchgrass	Units (per kg biomass)
Solid Waste	Heavy Metals to Soil	2.64E-08	5.13E-08	6.53E-08	kg

Table B-18: Energy Containing Material Inputs for LC Stage #2 for Biomass Transport for the Production of Ethanol

		Corn Grain	Corn Stover	Switchgrass	Units (per kg biomass)
Energy Containing Material Inputs	Crude Oil	8.14E-02	1.82E-01	2.37E-01	MJ
	Hard Coal	3.93E-03	4.62E-03	5.26E-03	MJ
	Lignite	5.88E-04	3.04E-04	3.50E-04	MJ
	Natural Gas	9.27E-03	1.64E-02	2.06E-02	MJ
	Uranium	2.09E-03	1.48E-03	1.79E-03	MJ
	Total	9.73E-02	2.05E-01	2.65E-01	MJ

B.3 Life Cycle Stage #3: Ethanol Production

The boundary of LC Stage #3 starts at the entrance to the ethanol plant with the receipt of feedstock material and ends at the entrance to the pipeline used to transport the liquid fuel to the bulk fuel storage depot. This LC stage also includes all CCS equipment and operations, beginning with the capture of CO_2 in the energy conversion facility and ending with sequestration in an underground geologic structure.

B.3.1 Ethanol Plant Costs

The costs included in LC Stage #3 for all cases are capital, non-fuel variable O&M, fixed O&M, and feed/fuel costs. By-product credit from power produced during the process is included, when applicable.

The NREL basis document on dilute acid pretreatment and biological conversion of corn stover (Aden *et al.*, 2002) and the NREL basis document on indirect corn stover gasification to mixed alcohols (Phillips, Aden *et al.*, 2007) include cost data applicable to the cellulosic feedstock cases of this study. Several data sources have been identified for the costs of the existing dry grinds that use corn grain as a feedstock. The most comprehensive source identified to this point is a U.S. Department of Agriculture cost model (USDA, 2008).

The cost data from the basis documents (Aden *et al*., 2002 and Phillips *et al*., 2007) and the USDA cost model (USDA, 2008) are summarized in **Table B-19.** The NETL CBTL Baseline Report (NETL 2009d) includes costs for CO_2 transportation, sequestration, and monitoring (TS&M). According to the NETL CBTL baseline (NETL, 2009d), the costs for the CO_2 components, including compressors and processes for water removal, are approximately 4

percent of the overall capital costs of the given case. Therefore, the capital costs for the CO_2 components of the advanced dry grind ethanol plant were assumed to be 4 percent of the total capital costs of each case.

A key assumption of this analysis is the cost of corn stover as received by a biochemical or thermochemical ethanol plant. 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 throat of the reactor have been rigorously developed by Idaho National Laboratory (INL 2009[1]). 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, we assume that the benefits with process improvements are offset by the increase in grower payment as the industry matures. Therefore, we assumed that the first payments to the growers would be $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).

The LCC analysis uses an RSP approach. The RSP is the minimum price at which the fuel should be sold in order to account for O&M and capital costs, taxes and other debt incurred through the construction and operation of the plant, and other LC components. The following equation demonstrates the calculation of RSP:

$$RSP(\$/galEthanolFuel) = \frac{(TPCxCCF) + [((O\&M)x(CF))/LF]}{(Output(gal))xCFx(1-loss)}$$

(Equation A-2)

Where:

TPC = total plant capital costs

CCF = capital charge factor

O&M = operating and maintenance costs (for this analysis, includes the cost of gasoline that is blended with the ethanol)

CF = capacity factor of the ethanol plant

LF = levelization factor

Output (gal) = output of the ethanol plant

loss = loss factor at the refueling station

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

Table B-19: Cost Model Summary for Corn Starch-to-Ethanol Pathways

	Units	Dry Grind	Advanced Dry Grind	Advanced Dry Grind w/ CCS
Plant Output				
Ethanol (denatured)	BPD	3,330	3,330	3,330
DDGS	kg/day	413,000	359,000	359,000
Corn oil	kg/day	N/A	44,300	44,300
Electricity	kWh/day	N/A	N/A	N/A
Higher alcohols	kg/day	N/A	N/A	N/A
Plant availability (capacity factor)	%	85%	85%	85%
				Utility and Feedstock Consumption
Corn	ton/day	1,380	1,380	1,380
Corn stover	ton/day	N/A	N/A	N/A
Switchgrass	ton/day	N/A	N/A	N/A
Electricity	kWh/day	119,000	130,000	346,000
Natural gas	MJ/day	4,730,000	4,540,000	4,540,000
Process water (from well)	L/day	2,060,000	2,060,000	2,060,000
Gasoline	kg/day	20,900	20,900	20,900
Lime	kg/day	N/A	N/A	N/A
Sulfuric acid	kg/day	N/A	N/A	N/A
Cost of Installed Capital	$2008	N/A	$94,600,000	$99,100,000
Fixed O&M (data year)	$2008/yr	$5,090,000	$5,090,000	$5,090,000
Equipment service life	yr	30	30	30

Table B-20: Cost Model Summary for Cellulose-to-Ethanol Pathways

	Units	Biochemical using Corn Stover and Combustion Energy Recovery	Biochemical using Switchgrass and Combustion Energy Recovery	Biochemical using Corn Stover and Gasification Energy Recovery	Biochemical using Switchgrass and Gasification Energy Recovery	Thermo-chemical using Corn Stover	Thermo-chemical using Switchgrass
Plant Output							
Ethanol (denatured)	BPD	4,020	4,020	4,020	4,020	3,580	3,580
DDGS	kg/day	N/A	N/A	N/A	N/A	N/A	N/A
Corn oil	kg/day	N/A	N/A	N/A	N/A	N/A	N/A
Electricity	kWh/day	367,000	519,000	710,000	949,000	N/A	N/A
Higher alcohols	kg/day	N/A	N/A	N/A	N/A	74,077	74,100
Plant availability (capacity factor)	%	85%	85%	85%	85%	85%	85%
Utility and Feedstock Consumption							
Corn	ton/day	N/A	N/A	N/A	N/A	N/A	N/A
Corn stover	ton/day	2,120	N/A	2,120	N/A	2,160	N/A
Switchgrass	ton/day	N/A	2,400	N/A	2,400	N/A	2,290
Electricity	kWh/day	N/A	N/A	N/A	N/A	N/A	N/A
Natural gas	MJ/day	N/A	N/A	N/A	N/A	N/A	N/A
Process water (from well)	L/day	3,660,000	4,540,000	3,780,000	3,920,000	769,000	814,000
Gasoline	kg/day	20,000	20,000	20,000	20,000	17,800	18,700
Lime	kg/day	46,900	53,200	46,900	53,200	N/A	N/A
Sulfuric acid	kg/day	64,400	73,000	64,400	73,000	N/A	N/A
Cost of Installed Capital (basis year 2008)	$2008	$133,000,000	$ 133,000,000	$ 133,000,000	$133,000,000	$146,000,000	$146,000,000
Fixed O&M (data year)	$2008/yr	$7,500,000	$7,500,000	$7,500,000	$7,500,000	$12,100,000	$12,100,000
Equipment service life	yr	30	30	30	30	30	30

B.3.2 Ethanol Plant Environmental

B.3.2.1 Current Dry Grind

Corn-ethanol typically refers to ethanol produced from the starchy grain, or kernel, of the corn plant. Starch is a polymer that is easily broken down by enzymes in the human stomach into its monomer, glucose (sugar). A similar process is used to create ethanol: enzymes are used to breakdown the starch molecules into sugar, which is then fermented by yeast into ethanol. There are two main commercial processes for converting starch into ethanol: wet and dry grinding. Wet grinding, a classic corn processing technology, separates the components of the corn kernel to create several products: ethanol or corn syrup from starch, corn oil from germ, wet feed from fiber, and dry protein (gluten meal) from wet gluten (DOE, 2009). However, efficient wet mill facilities need to have a large capacity, which requires a large capital investment and feedstock supply. Therefore, wet mill processing is not considered in this study. Dry milling is the more popular production method, currently producing 88 percent of ethanol in the United States (EPA, 2009a), because it can be economical and efficient on a smaller scale. In dry grinding, the entire kernel is ground and fed with enzymes and water into a cooker to create sugar. After the sugar is fermented into ethanol, solids and liquids are separated and recombined into distiller's grains (DG), a high-protein animal feed which can be sold wet (wet distillers grain [WDG]) or as dried distillers grains with solubles (DDGS). The average dry grind operating today has a capacity of approximately 61.9 million gallons per year and operates at 88 percent capacity (EPA, 2009a). **Figure B-4** shows the typical dry grinding process (EPA, 2009a).

Traditional dry grind plants use a hammer mill to grind corn feedstock to a meal, which is then cooked in a two-stage process. The process starts with the formation of hot slurry that is combined with enzymes and maintained at a specific pH and a temperature between 180°F and 190°F for up to 45 minutes. Next, a pressurized cooker elevates the temperature to 220°F for five minutes. The mixture is then cooled to 180°F to 190°F for a couple hours, which initiates the decomposition of the starch to shorter carbohydrate chains. Yeast is then added to the mixture, which is fermented for approximately 60 hours. The resulting mixture, which is up to 15 percent ethanol by volume, is fed to a distillation column that separates the ethanol from water and non-fermentable solids. At this point, the ethanol contains five percent water by volume; this water is removed by passing the ethanol through a vapor phase molecular sieve. Finally, a denaturant (such as gasoline) is added to the pure ethanol to make it unfit for human consumption (EPA, 2009a).

For this study, it is assumed that the current dry grind is an existing facility. This is due to several factors, including the large number of commercial-scale dry grind ethanol plants in operation and the current policies surrounding renewable fuels. If the proposed RFS2 is passed as written, new current dry grind ethanol plants would not be built because they do not fall under the 20 percent GHG reduction threshold requirement for renewable fuels (EPA, 2009b). However, any plant built before December 19, 2007, will be grandfathered in and would not be subject to the regulation. Therefore, assuming successful implementation of RFS2, new construction of the current dry grind technology will not occur within the timeframe of this study (2012 through 2042).

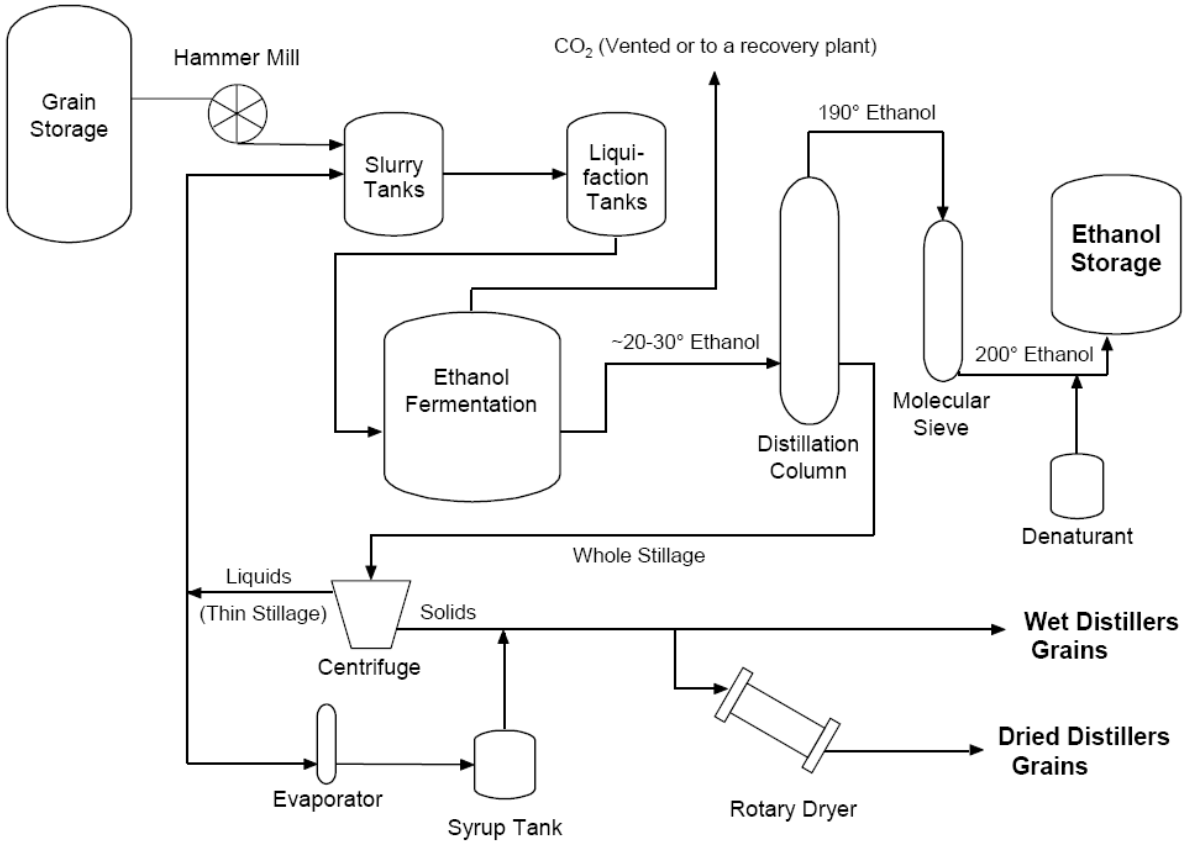

Figure B-4: Typical Dry Grinding Process (EPA, 2009a)

CO_2, which results from the fermentation of sugar, is a by-product of ethanol production. This CO_2 can be captured, cleaned, and sold to the food processing industry where local markets exist; however, it was assumed that dry grind ethanol plants vent CO_2 directly to the atmosphere. From an economic perspective, it was assumed that the sale of CO_2 to the food processing industry is not feasible for most ethanol dry grinds due to the relatively low market value of CO_2 as well as the increased capital and operating expenses required for capturing and cleaning CO_2. From an environmental perspective, if CO_2 were sold to the food processing industry, which uses CO_2 for the carbonation of beverages or flash freezing applications, it would eventually be released to the atmosphere. Thus, while the food processing industry may delay the release of CO_2 to the atmosphere, the net CO_2 emissions are the same whether it is released at the site of ethanol production or by the food processing industry.

The stillage that remains after ethanol is separated in the distillation column contains solids from the grain and water. A portion of this stillage is thin enough to be routed back to the cooking process, which reduces the amount of fresh water required by the plant. The thicker portion of this stillage is sent through a drying system to produce dried distillers grains with solubles (DDGS), which can be used as a high-protein substance suitable for animal feed on cattle feed lots or at dairy farms. This study assumes that all DDGS is dried completely and sold as animal feed; no wet distillers grains (another possible co-product of dry grind ethanol plants) are produced by this particular process.

B.3.2.2 *Advanced Dry Grind with Corn Oil Extraction*

Because existing corn ethanol dry grind facilities do not meet the current GHG reduction threshold, many ethanol producers are looking for additional ways to reduce their GHG emissions. One such method is corn oil extraction, where, before drying, the DDGS is treated with a solvent to remove corn oil. This produces a co-product, which can be sold as a displacement for biodiesel oil-feedstocks and reduces the energy consumption of DDGS drying. As stated in RFS2 (EPA, 2009a), by 2030 30 percent of plants will be extracting corn oil as a co-product.

Corn oil can be extracted at a dry grind before or after fermentation. Each alternative has advantages and disadvantages. When corn oil is extracted before fermentation, the kernel is separated into the bran, starch, and germ components. This results in relatively pure corn oil and other saleable co-product streams, and also results in a relatively high ethanol yield. However, the removal of corn oil prior to fermentation has relatively high capital costs and is suitable only for new construction (i.e., it cannot be retrofitted to existing dry grind plants). Alternatively, the technology for extraction of corn oil from DDGS after fermentation is relatively inexpensive and can be easily retrofitted to an existing dry grind at a low cost. The corn oil that is extracted from DDGS is considered a "distressed" corn oil stream that cannot be used by the food products industry, but is a viable feedstock for bio-diesel facilities.

The advanced dry grinds used as a basis for the RFS2 standards are based on (EPA, 2009a, p 50) the extraction of corn oil from DDGS (an extraction step that occurs after fermentation). Additionally, the basis documents for this study more accurately represent the extraction of corn oil from DDGS than the extraction of corn oil prior to fermentation. Thus, for the advanced dry grind pathways, this study models corn oil extraction from DDGS.

B.3.2.3 *Advanced Dry Grind with CCS*

This case uses the same data and assumptions as used by the Advanced Dry Grind with Corn Oil Extraction process, except for the addition of a CCS system.

The purity of the vent stream from the advanced dry grind is 98% CO_2 (USDA, 2008). It is thus assumed that the remaining 2 percent of this stream is water and that further purification is not necessary. The power required is 3.24 MW, assuming the inlet is at 15 psia (atmospheric pressure) and 80°F, and the outlet is at 2200 psia (the pressure of the CO_2 sequestration pipeline) and 100°F. The system consists of a multistage centrifugal compressor with four interstage cooling steps. The compressor has 80 percent efficiency, and the gas temperature is limited to 300°F throughout the process. The construction of the carbon capture system is accounted for in the overall advanced dry grind construction calculations, which are discussed in **Section B**.3.2**.**

Both the operation and construction of the CO_2 pipeline are modeled. CO_2 transport pipeline construction consists of two sub-processes: (1) manufacture of the pipe and (2) installation of the pipeline. The following describes the modeling assumptions applied to each.

Pipeline manufacture is based on the mass of steel required to construct the pipeline segment. The required mass of steel is calculated based on the length of the pipe and the pipe size. The pipeline diameter and internal wall thickness is dependent on the mass of CO_2 required to be transported to the by-product use or sequestration site. The mass of CO_2 to be transported varies for each pathway. As a result, the CO_2 pipelines are sized to meet both structural integrity requirements and to ensure the CO_2 remains in the supercritical fluid state over the length of

pipe. The corresponding mass of construction material is determined based on the physical dimensions of the pipeline (Engineering Tool Box, 2006). An additional 10 percent is added to the total mass of the pipeline to account for valves and fittings. The pipeline is assumed to be constructed of 100 percent welded steel pipe consisting of 80 percent recycled steel. The International Iron and Steel Institute (IISI) profile for "Welded Steel Pipe, Blast Furnace Production, with 80 percent Recycled Steel Feedstock" is used to estimate the cradle-to-gate environmental profile for CO_2 pipeline manufacturing (IISI, 2006). Emissions related to underground pipeline installation include heavy construction equipment exhaust emissions, emissions from transport of pipes and associated materials (200 miles round-trip), and fugitive dust. Pipeline installation emissions are estimated based on the Cosumnes Power Plant construction permit filed with the Sacramento Municipal Utility District, California, in 2001 (SMUD, 2001). The data are derived from Appendix 8.1A.2: Pipelines and Transmission Lines. The emissions data was originally calculated for the construction of a natural gas pipeline. The installation factors are scaled based on the length of pipe to be installed.

Water usage for hydro testing the pipeline is excluded because the water is assumed to be returned to the source after use. The CO_2 transport pipeline is sized to minimize the pressure drop from the energy conversion facility to the by-product use or sequestration site to ensure the product remains in a single-phase supercritical fluid state. CO_2 transported by this pipeline is stored in a geologic sequestration site. Monitoring of CO_2 leakage from the site is assumed by the NETL CBTL baseline (NETL, 2009d) to be performed for 80 years. A one percent loss of CO_2 during the lifetime of the CO_2 sequestration site is assumed. 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.

B.3.2.4 *Cellulosic Biochemical Conversion with FBC Cogeneration*

Issues associated with the availability of viable cropland, rising food prices, and GHG emissions have shifted the focus of ethanol production towards cellulosic feedstocks. Cellulose is found in any plant structure, and, like starch, is a polymer of glucose. Cellulose is surrounded by hemicellulose (a polymer of several sugars including xylose, which also can be fermented to ethanol) and lignin (a complex polymer that can be best described as glue which holds together the plant structure). This complex nature of lignocellulosic biomass requires more energy and more specific enzymes to overcome the recalcitrance of the biomass.

Although the fractions vary, cellulosic material (also called lignocellulosic) typically consists of approximately 20 to 30 percent hemicellulose, 40 to 50 percent cellulose, and the rest lignin and other organic extractives (Wyman, 2007). Lignin and some fractions of hemicellulose can actually inhibit hydrolysis (the step which breaks down the cellulose into glucose) and fermentation to ethanol. However, the promise of an abundant, non-food based source of ethanol has led to many research studies and pilot plants dedicated to cost-effectively converting cellulosic feedstocks. Common cellulose feedstocks include agricultural residues (corn stover), dedicated herbaceous energy crops (switchgrass, mischanthus), dedicated woody energy crops (hybrid poplars), forest products and residues, and even waste streams like urban wood waste (UWW) or the cellulosic fraction of municipal solid waste (MSW). For this study, the conversion of corn stover and switchgrass to ethanol is being considered. When developing a pathway to cellulosic ethanol production, one wants to maximize ethanol yield while reducing

costs with the main goal of producing fuel with a minimum selling price comparable to corn-based ethanol.

The most studied route to cellulosic ethanol is biochemical conversion because it is the same general pathway as the one used in corn-ethanol production: enzymatic conversion to sugar and fermentation to ethanol. The major difference is the addition of a biomass pretreatment step, which is an expensive, yet crucial, processing step of cellulosic production (Wyman, 2007). **Figure B-5** provides a schematic of the goal of pretreatment as reported in a 2005 review of current and promising pretreatment technologies (Mosier *et al.*, 2005).

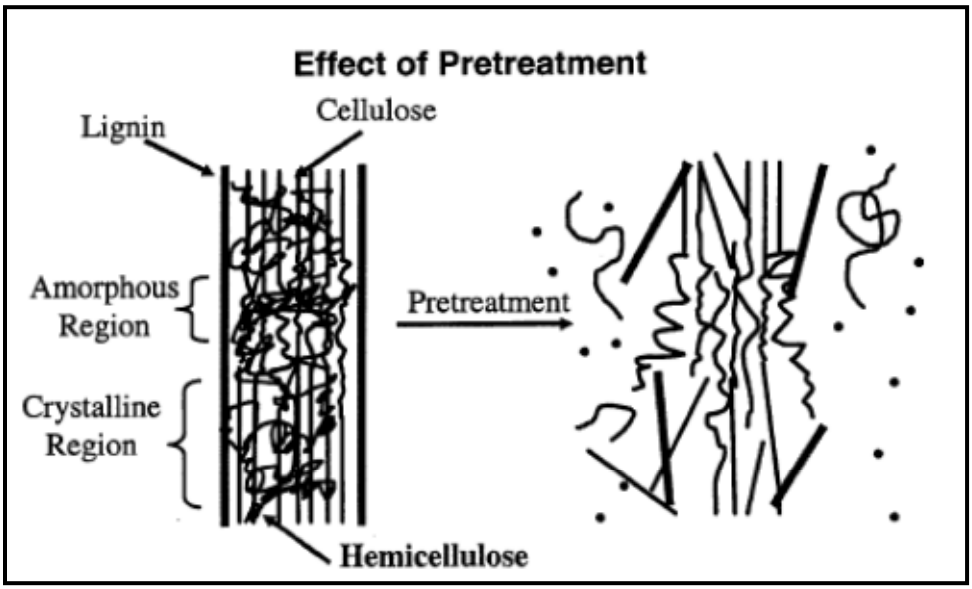

Figure B-5: Schematic of the Goal of Pretreatment (Mosier *et al.*, 2005)

An ideal pretreatment breaks apart the lignin structure to make the cellulose and hemicellulose sugars more accessible to enzymes, therefore maximizing the ethanol yield. However, pretreatments either tend to be too harsh and degrade the cellulose, or too weak and don't remove all the lignin, which in both cases leads to low ethanol yields.

Currently, dilute-acid pretreatment seems to be the most popular process, the pathway of which was well defined in a 2002 NREL study focused on determining the minimum ethanol selling price (Aden *et al.*, 2002). In short, the feedstock is shredded and then exposed to a dilute sulfuric acid catalyst at high temperatures for a short time, which liberates the hemicellulose sugars and other compounds (Aden *et al.*, 2002). During separation, washing removes the acid from the solids for neutralization; overliming (or over neutralizing) is required to insure all compounds toxic to fermentation (that were liberated during pretreatment) are removed. Enzymatic hydrolysis (or saccharification) is then coupled with co-fermentation through a series of tanks, and most of the cellulose and xylose are converted to ethanol after several days (this process is called SSCF, which stands for simultaneous saccharification with co-fermentation).

Supporting processes to the biochemical conversion of cellulose include wastewater treatment, which is necessary to digest the organics that result from fermentation. The methane generated from wastewater treatment is combusted for energy recovery and the treated water is returned to the process. A fluidized bed combustor capable of handling inputs with a wide array of characteristics (i.e., varying moistures and heating values) is used for the combustion of the

methane, residual biomass, and other waste materials from the process. The fluidized bed combustor has 68 percent boiler efficiency and is followed by a multistage steam turbine that generates electricity. Excess electricity is the only co-product of this technology that exits system boundaries. **Figure B-6** is the process flow document from the 2002 NREL study (Aden *et al.*, 2002).

The basis document for the ethanol plant that uses the biochemical conversion of cellulosic feedstocks (Aden *et al*., 2002) provides a description of a wastewater treatment system, but it does not provide data on the characteristics of discharged wastewater. Furthermore, since this type of technology has not yet been employed on a commercial scale, no primary data are available on the quality of wastewater discharges from ethanol plants that use biochemical conversion of cellulosic feedstocks. Due to this data limitation, the waterborne emissions from ethanol plants that use biochemical conversion of cellulosic feedstocks are not included in this analysis.

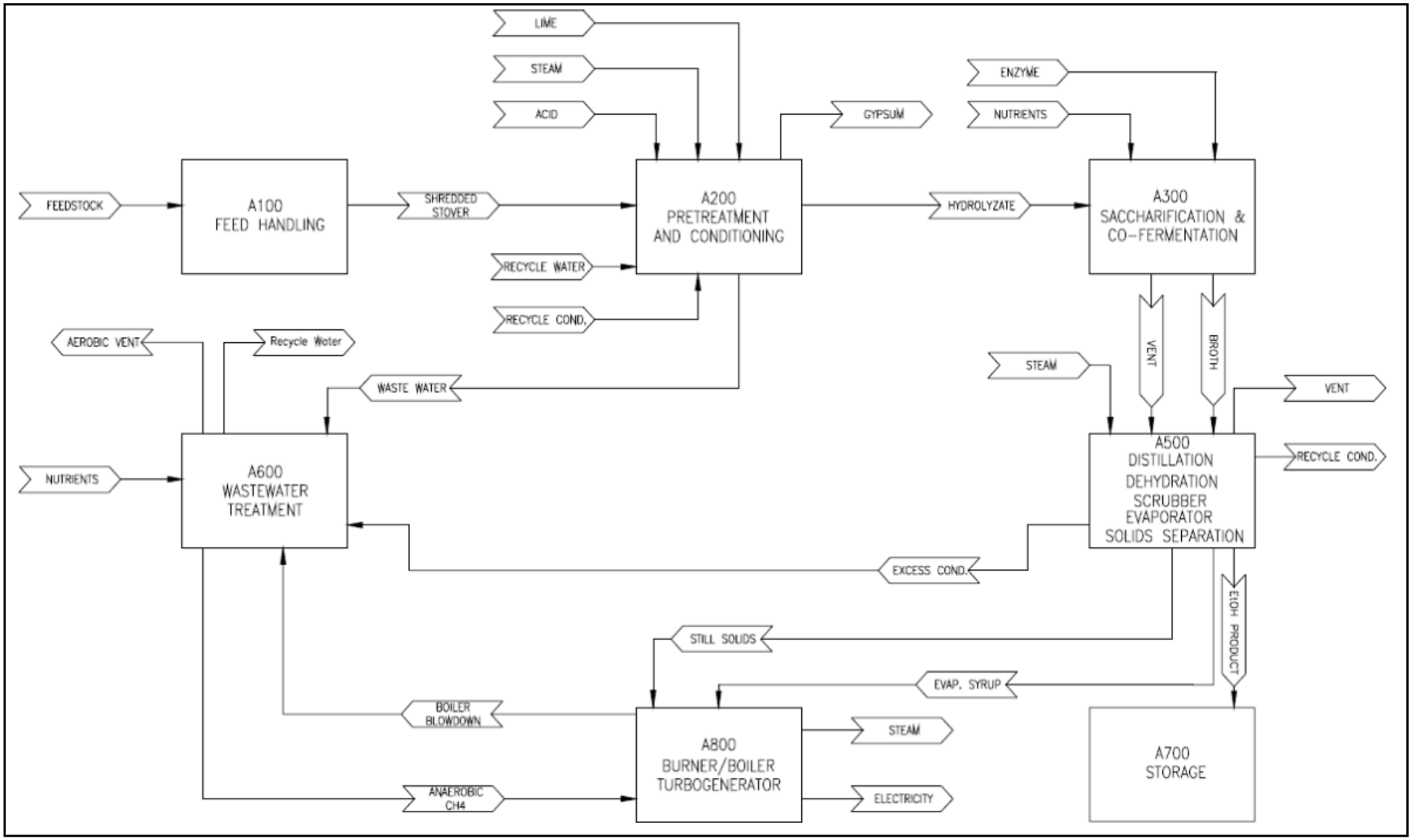

Figure B-6: Process Flow Document for a Dilute Acid Cellulosic Ethanol Facility (Aden *et al.*, 2002)

B.3.2.5 *Cellulosic Biochemical Conversion with Gasification Co-Generation*

The key technology distinction of this case is that it uses gasification instead of combustion of lignin to create excess electricity. No data are available in the basis document (Aden *et al*., 2002) for the operation of a gasifier. The gasifier used for an ethanol facility that produces ethanol through gasification of cellulosic biomass, as modeled by NREL (Phillips *et al.*, 2007), is used as a surrogate to estimate the energy and material streams associated with the gasification of by-product biomass.

B.3.2.6 *Cellulosic Gasification*

In this case cellulosic biomass is gasified using oxygen or air (direct), or hot sand (indirect) to produce syngas, an intermediate product of carbon monoxide (CO) and hydrogen (H_2) that can be converted into ethanol and other co-products via a mixed alcohol synthesis (Phillips, 2007). The benefit of this process compared to the biochemical pathways discussed above is that it does not require biomass pretreatment, enzymes, or microorganisms. Within reason, any cellulosic biomass can be processed via gasification (different types will require different processing conditions based on chemical composition). However, gasification is often overlooked when considering ethanol production because it is in the spotlight for other renewable energies, like biodiesel and co-gasification with coal for electricity. Some downfalls of gasification include additional processing problems like tar build-up, feedstock specific emissions such as HCI, and scale up (Tillman, 2000). **Figure B-7** shows the process block diagram for biomass gasification to ethanol (Phillips *et al.*, 2007).

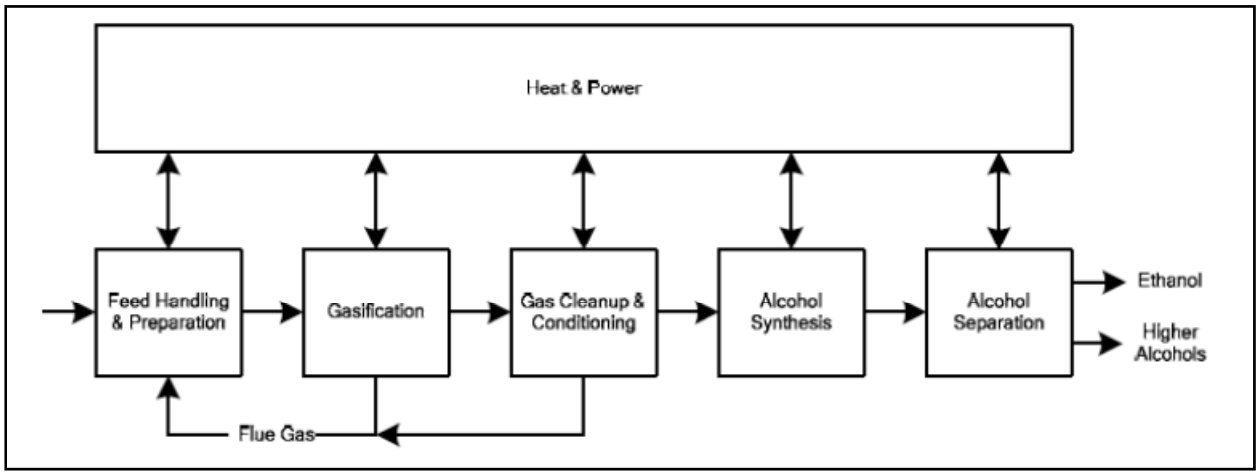

Figure B-7: Process Block Diagram for Biomass Gasification to Ethanol (Phillips *et al.*, 2007)

The first step in the process is feed handling and preparation, which dries the biomass feedstock. The next step is indirect gasification, which circulates synthetic olivine mineral between a gasifier and char combustor; the olivine supplies the heat that is necessary for the endothermic gasification reactions. Steam is injected into the gasifier to stabilize the flow of biomass and sand. The biomass converts to a mixture of syngas components (CO, H_2, CO_2, and CH_4), tars, and a solid char that is composed of carbon residue. The gas that exits the gasifier is first cleaned with a scrubber, which removes particulates, ammonia, and tars. An additional gas-cleaning step uses an amine unit to recover CO_2 and hydrogen sulfide (H_2S) (the CO_2 is vented to the atmosphere and the H_2S is reduced to elemental sulfur and disposed as solid waste). It is necessary to remove these impurities in order to prevent contamination of the catalyst in the

fixed bed reactor, the next step in the process, which converts the syngas to liquid alcohols. After alcohols are synthesized in the fixed bed reactor, they are routed to a flash separator, dehydrated using molecular sieves, and then fed to a distillation column that separates methanol and ethanol from the alcohols with higher molecular weights. A second distillation column separates the methanol and ethanol; the methanol is used to flush water from the molecular sieves and then recycle it to the entrances of the alcohol synthesis reactor. The design includes a conventional steam cycle that produces heat required for the gasifier and other operations, as well as electricity that can be used for internal operations or exported as a co-product. The integration of heat exchangers throughout the process allows the recovery of heat for the generation of steam.

It is possible that the conditions in a gasifier produce complex organic compounds that are eventually discharged in wastewater; however, no data are available for the quality of wastewater discharged from thermochemical ethanol plants that employ the technology described above. The basis document for thermochemical ethanol plants (Phillips *et al*., 2007) compares the wastewater of modern dry grind ethanol plants to the wastewater of the thermochemical ethanol plants. Recently-constructed dry grind ethanol plants recycle a large share of process water. In fact, some dry grind ethanol plants are known as "zero discharge" facilities, meaning that no water is discharged from wastewater treatment (Phillips *et al*., 2007). Thus, one design goal of the thermochemical ethanol plant is to achieve "zero discharge" characteristics that can compete with the relatively low water consumption and low wastewater discharges of newer dry grind ethanol plants. The basis document for the thermochemical ethanol plant (Phillips *et al*., 2007) does not include characteristics on wastewater discharges. Furthermore, since this type of technology has not been commercialized, no primary data are available on the quality of wastewater discharges from thermochemical ethanol plants. Due to this data limitation, the waterborne emissions from thermochemical ethanol plants are not included in this analysis.

B.3.1 Ethanol Plant Electricity Profile

The ethanol plants modeled in this analysis are assumed to be in the U.S. Midwest. To be consistent with this geography, the fuel profile of the MROW (Midwest Reliability Organization West) electricity grid is used to model the generation of electricity for ethanol production facilities as well as the displacement of electricity for cases where electricity is sold by ethanol plants. The fuel profile of the MROW grid is shown in **Table B-21**.

Table B-21: Fuel Profile for MROW and Other Electricity Grids

Fuel	Region			
	Iowa	Nebraska	MROW	U.S.
Coal	77.5%	66.2%	73.5%	49.6%
Oil	0.34%	0.10%	0.60%	3.03%
Gas	5.64%	2.55%	4.04%	18.8%
Biomass	0.26%	0.14%	0.76%	1.30%
Hydro	2.18%	2.77%	4.15%	6.50%
Nuclear	10.3%	28.0%	14.6%	19.3%
Wind	3.74%	0.31%	2.07%	0.44%
Solar	0.00%	0.00%	0.00%	0.01%
Geothermal	0.00%	0.00%	0.00%	0.36%

Other	0.03%	0.00%	0.25%	0.70%
Total	100%	100%	100%	100%

B.3.2 Ethanol Plant Construction Processes

Construction of the ethanol plants is based on the estimated amount of concrete and steel required to construct each plant. The construction requirements for a conventional ethanol dry grind plant are not included in this study because it is assumed to be an existing facility. The material requirements for a typical ethanol dry grind facility are available in the literature (Hill *et al*., 2006), and this analysis uses the relative capital costs to adjust these values upward to account for corn oil extraction and CCS equipment.

No data are available on the construction materials required for a corn oil extraction unit, but a producer of corn oil separation systems states that the costs to add corn oil extraction equipment to an ethanol plant increases total plant capital costs by less than 10 percent (Greenshift, 2010). Additionally, a representative of a 52 MGY ethanol plant stated that the cost of corn oil extraction equipment for their facility was $2 million (McElroy, 2007), which is less than 2 percent of the approximately $90 million cost for capital required for the conventional dry grind plant modeled in this analysis (USDA, 2008). Based on this 2 to 10 percent range in additional capital costs, the material requirements for the construction of a dry grind with corn oil extraction is assumed to be 5 percent higher than the material requirements of a conventional dry grind.

The capital cost of the advanced dry grind with CCS is assumed to be 10 percent higher than the conventional dry grind. The CO_2 vent stream is 98 percent pure and the compressor train is the key equipment necessary for CO_2 recovery. Due to the modest equipment requirements for CO_2 recovery system at a dry grind ethanol plant; this analysis assumes that the addition of a CO_2 capture system increases the material requirements of the ethanol plant by a relatively small amount (5 percent). When combined with the construction requirements of a corn oil extraction unit, the construction material requirements of an ethanol dry grind with corn oil extraction and CO_2 capture are assumed to be 10 percent higher than a conventional dry grind ethanol plant. The foregoing assumptions were made because detailed cost data for the advanced dry grind technologies are not available; this is a data limitation of this analysis.

The basis documents for this analysis include capital costs for the construction of ethanol plants that use cellulosic feedstocks. Using cost factors for the design of high-pressure vessels, the weight of carbon steel and stainless steel were estimated. The concrete requirements for the cellulosic ethanol plants were calculated using the estimated area required for the process equipment and an assumed concrete thickness and density.

B.3.1 Ethanol Plant Environmental Profiles

The following tables (**Table B-22** through **Table B-28**) show the LC stage environmental profiles for biomass transport.

Table B-22: GHG Emissions from LC Stage #3 Petroleum Refinery and Ethanol Operations

Liquid Fuel Production Facility	Mass Emitted to Atmosphere (kg CO_2e/MJ Fuel Product)			
	CO_2	CH_4	N_2O	Total
Ethanol Dry Grind	8.52E-01	3.35E-02	1.32E-03	8.86E-01
Advanced Ethanol Dry Grind	7.10E-01	2.94E-02	-3.72E-04	7.39E-01
Advanced Ethanol Dry Grind w/ CCS	3.30E-01	3.34E-02	1.72E-04	3.63E-01
Cellulose Fermentation (corn stover) with Combustion Energy Recovery	-4.16E-01	-2.95E-03	-1.32E-03	-4.20E-01
Cellulose Fermentation (switchgrass) with Combustion Energy Recovery	-6.12E-01	-7.46E-03	-2.06E-03	-6.21E-01
Cellulose Fermentation (corn stover) with Gasification Energy Recovery	-8.71E-01	-1.88E-02	-3.09E-03	-8.93E-01
Cellulose Fermentation (switchgrass) with Gasification Energy Recovery	-1.18	-2.74E-02	-4.29E-03	-1.22
Cellulose Gasification (corn stover)	3.92E-02	3.95E-03	3.30E-04	4.34E-02
Cellulose Gasification (switchgrass)	3.92E-02	3.95E-03	3.30E-04	4.34E-02

Table B-23: CAP Emissions from LC Stage #3 Petroleum Refinery and Ethanol Operations

Liquid Fuel Production Facility	Mass of Pollutant Emitted to Atmosphere (kg/MJ Fuel Product)					
	NO_X	SO_2	CO	VOC	PM	Lead
Ethanol Dry Grind	6.57E-04	3.68E-03	8.34E-04	1.65E-04	4.65E-05	1.62E-08
Advanced Ethanol Dry Grind	-1.87E-04	3.77E-03	3.25E-04	-2.86E-04	6.97E-05	1.77E-08
Advanced Ethanol Dry Grind w/ CCS	7.64E-05	4.50E-03	3.82E-04	-2.70E-04	9.30E-05	2.67E-08
Cellulose Fermentation (corn stover) with Combustion Energy Recovery	-7.71E-04	-1.29E-03	2.40E-04	2.53E-05	-4.95E-05	1.30E-08
Cellulose Fermentation (switchgrass) with Combustion Energy Recovery	-1.14E-03	-2.24E-03	1.65E-04	1.03E-05	-8.00E-05	4.09E-09
Cellulose Fermentation (corn stover) with Gasification Energy Recovery	-1.62E-03	-4.15E-03	-1.56E-04	-2.28E-05	-1.20E-04	-9.27E-09
Cellulose Fermentation (switchgrass) with Gasification Energy Recovery	-2.20E-03	-5.72E-03	-2.78E-04	-5.03E-05	-1.69E-04	-2.40E-08
Cellulose Gasification (corn stover)	7.80E-05	1.12E-04	1.92E-04	2.72E-05	2.19E-05	3.05E-08
Cellulose Gasification (switchgrass)	7.80E-05	1.12E-04	1.92E-04	2.72E-05	2.19E-05	3.05E-08

Table B-24: Air Emission Species of Interest from LC Stage #3 Petroleum Refinery and Ethanol Operations

Liquid Fuel Production Facility	Mass of Pollutant Emitted to Atmosphere (kg/MJ Fuel Product)					
	Mercury	Ammonia	HCl	HF	NO	NMVOC
Ethanol Dry Grind	2.91E-09	1.44E-06	4.83E-06	6.48E-07	1.02E-11	1.65E-04
Advanced Ethanol Dry Grind	3.16E-09	-2.81E-04	3.07E-06	5.14E-07	1.01E-11	-2.86E-04
Advanced Ethanol Dry Grind w/ CCS	5.31E-09	-2.80E-04	6.07E-06	8.97E-07	1.12E-11	-2.70E-04
Cellulose Fermentation (corn stover) with Combustion Energy Recovery	-3.34E-09	-1.61E-06	-8.99E-06	-1.27E-06	-2.68E-12	2.53E-05
Cellulose Fermentation (switchgrass) with Combustion Energy Recovery	-5.63E-09	-2.48E-06	-1.32E-05	-1.81E-06	-4.24E-12	1.03E-05
Cellulose Fermentation (corn stover) with Gasification Energy Recovery	-8.71E-09	2.64E-05	-1.87E-05	-2.52E-06	-6.31E-12	-2.28E-05
Cellulose Fermentation (switchgrass) with Gasification Energy Recovery	-1.24E-08	2.90E-05	-2.53E-05	-3.38E-06	-8.79E-12	-5.03E-05
Cellulose Gasification (corn stover)	1.96E-09	1.70E-05	8.27E-07	1.73E-08	7.91E-13	2.72E-05
Cellulose Gasification (switchgrass)	1.96E-09	1.70E-05	8.27E-07	1.73E-08	7.91E-13	2.72E-05

Table B-25: Water Emissions from LC Stage #3 Petroleum Refinery and Ethanol Operations

Liquid Fuel Production Facility	Mass Emitted to Body of Water (kg/m^3 Fuel Product)							
	Aluminum	Ammonia	Heavy metals	HCl	Nitrate	Nitrogen	Phosphate	Phosphorus
Ethanol Dry Grind	1.16E-06	1.14E-06	2.38E-04	6.04E-11	6.47E-06	1.04E-09	1.93E-08	7.72E-08
Advanced Ethanol Dry Grind	1.24E-06	1.22E-06	2.56E-04	5.92E-11	7.29E-06	1.02E-09	2.05E-08	7.82E-08
Advanced Ethanol Dry Grind w/ CCS	1.92E-06	1.75E-06	4.04E-04	6.42E-11	1.11E-05	1.10E-09	2.15E-08	8.70E-08
Cellulose Fermentation (corn stover) with Combustion Energy Recovery	-2.25E-06	-1.08E-06	-5.07E-04	-1.09E-11	-1.26E-05	2.32E-08	5.95E-08	1.34E-07
Cellulose Fermentation (switchgrass) with Combustion Energy Recovery	-3.21E-06	-1.81E-06	-7.18E-04	-1.80E-11	-1.81E-05	2.62E-08	5.92E-08	1.37E-07
Cellulose Fermentation (corn stover) with Gasification Energy Recovery	-4.47E-06	-2.80E-06	-9.90E-04	-2.73E-11	-2.51E-05	2.29E-08	5.67E-08	1.05E-07
Cellulose Fermentation (switchgrass) with Gasification Energy Recovery	-6.01E-06	-3.98E-06	-1.33E-03	-3.86E-11	-3.37E-05	2.58E-08	5.57E-08	1.01E-07
Cellulose Gasification (corn stover)	1.96E-08	5.84E-07	4.21E-06	4.73E-12	4.69E-07	8.22E-11	5.46E-08	4.13E-08
Cellulose Gasification (switchgrass)	1.96E-08	5.84E-07	4.21E-06	4.73E-12	4.69E-07	8.22E-11	5.46E-08	4.13E-08

Table B-26: Water of LC Stage #3 Petroleum Refinery and Ethanol Operations

Liquid Fuel Production Facility	Volume of Water (m^3/MJ Fuel Product)		
	Water In	Water Out	Net
Ethanol Dry Grind	8.67E-03	5.16E-03	3.51E-03
Advanced Ethanol Dry Grind	-3.23E-01	5.27E-03	-3.28E-01
Advanced Ethanol Dry Grind w/ CCS	-3.21E-01	6.21E-03	-3.27E-01
Cellulose Fermentation (corn stover) with Combustion Energy Recovery	6.06E-03	4.27E-04	5.63E-03
Cellulose Fermentation (switchgrass) with Combustion Energy Recovery	7.31E-03	4.69E-04	6.84E-03
Cellulose Fermentation (corn stover) with Gasification Energy Recovery	5.28E-03	4.27E-04	4.85E-03
Cellulose Fermentation (switchgrass) with Gasification Energy Recovery	4.87E-03	4.84E-04	4.38E-03
Cellulose Gasification (corn stover)	1.63E-03	3.32E-04	1.30E-03
Cellulose Gasification (switchgrass)	1.64E-03	3.35E-04	1.31E-03

Table B-27: Solid Waste of LC Stage #3 Petroleum Refinery and Ethanol Operations

Liquid Fuel Production Facility	Mass Emitted (kg/MJ Fuel Product)		
	Heavy Metals to Soil	Solid Waste (Unspecified)	Total
Ethanol Dry Grind	2.30E-06	9.33E-07	3.23E-06
Advanced Ethanol Dry Grind	2.25E-06	1.02E-06	3.27E-06
Advanced Ethanol Dry Grind w/ CCS	2.36E-06	1.70E-06	4.06E-06
Cellulose Fermentation (corn stover) with Combustion Energy Recovery	1.03E-06	-2.38E-06	-1.35E-06
Cellulose Fermentation (switchgrass) with Combustion Energy Recovery	9.99E-07	-3.36E-06	-2.36E-06
Cellulose Fermentation (corn stover) with Gasification Energy Recovery	6.81E-07	-4.61E-06	-3.93E-06
Cellulose Fermentation (switchgrass) with Gasification Energy Recovery	5.64E-07	-6.16E-06	-5.59E-06
Cellulose Gasification (corn stover)	4.10E-07	3.84E-09	4.14E-07
Cellulose Gasification (switchgrass)	4.10E-07	3.84E-09	4.14E-07

Table B-28: Energy Containing Material Inputs to LC Stage #3 Petroleum Refinery and Ethanol Operations

Process	Energy Containing Materials (MJ/MJ Ethanol)					
	Crude Oil	Hard Coal	Lignite	Natural Gas	Uranium	Total
Ethanol Dry Grind	9.34E-02	1.04E-01	1.28E-03	3.30E-01	2.98E-02	5.59E-01
Advanced Ethanol Dry Grind	9.39E-02	1.05E-01	1.29E-03	2.95E-01	2.61E-02	5.22E-01
Advanced Ethanol Dry Grind w/ CCS	9.58E-02	1.71E-01	1.59E-03	3.00E-01	4.29E-02	6.11E-01
Cellulose Fermentation (corn stover) with Combustion Energy Recovery	1.06E-01	-2.23E-01	-1.91E-04	1.73E-05	-5.47E-02	-1.72E-01
Cellulose Fermentation (switchgrass) with Combustion Energy Recovery	1.09E-01	-3.18E-01	-5.21E-04	-5.28E-03	-7.83E-02	-2.93E-01
Cellulose Fermentation (corn stover) with Gasification Energy Recovery	9.98E-02	-4.39E-01	-1.19E-03	-1.40E-02	-1.10E-01	-4.64E-01
Cellulose Fermentation (switchgrass) with Gasification Energy Recovery	1.06E-01	-3.04E-01	-3.25E-03	5.10E-02	-7.26E-02	-2.23E-01
Cellulose Gasification (corn stover)	3.98E-01	2.48E-02	4.21E-03	2.87E-02	6.11E-03	4.62E-01
Cellulose Gasification (switchgrass)	4.12E-01	2.71E-02	5.85E-03	5.90E-02	8.91E-03	5.13E-01

B.4 Life Cycle Stage #4: Ethanol Transport

LC Stage #4 begins where denatured ethanol exits ethanol product facilities, and ends with the fueling of a passenger vehicle. This stage includes product transport to bulk storage facilities and subsequent transport to refueling terminals.

B.4.1 Ethanol Transport Costs

B.4.1.1 *Domestic Pipeline Transport Costs*

The dedicated ethanol pipeline between the ethanol production facility and the bulk loading terminal and the specialized ethanol storage tanks at the bulk loading facilities are not existing infrastructure; thus, the construction of the ethanol pipeline and storage tanks are included in this study. Transport vehicles are not considered to be existing, thus manufacturing of transport vehicles is included in this LC stage.

A 100-mile pipeline is constructed between the ethanol plant and bulk storage depot for the transport of ethanol. Pipeline transport costs are dependent on two variables: (1) pipe diameter and (2) pipe length. The requirements for the size of the pipe are determined by the mass flow of the product transported.

The power requirement for pipeline transport of ethanol is assumed to be comparable to the power requirement for pipelines used for petroleum products. The electricity required for petroleum pipeline transport is 0.025 kWh/ton-mile (Oregon DEQ, 2004 and NETL, 2008). The quantity of the electricity required to transport ethanol is multiplied by the national average industrial price of electricity as shown by the high price projection tables in AEO 2009 (Table 3: Energy Prices by Sector and Source) (EIA, 2009). In 2008 dollars, the national average price of industrial electricity is $0.065/kWh. This analysis uses the high price projection tables based on the assumption that energy prices will increase, economic growth will occur, and restrictions will be imposed on conventional energy sources during the study period.

B.4.1.2 *Bulk Storage Depot Costs*

Only O&M costs are accounted for at the bulk terminal, as it is considered to be an existing terminal. However, the costs for the addition of ethanol storage tanks (which must have fixed roofs that prevent water contamination) are included in the LCC model. The size of the bulk storage facility is based on the inflow rate from the pipeline transmission of fuel and the daily amount taken out by tanker trucks, plus additional storage. The fixed O&M costs are determined on the basis of the storage facility size.

The annual quantity of electricity required for a bulk storage depot is not available in the literature, and thus is a data limitation for both the cost and environmental models. Annual energy needed to operate the fuel-processing portion of a refueling facility is used as surrogate data for this portion of the transport cost model. The quantity of the electricity required for the bulk storage facility is multiplied by the national average industrial price of electricity as shown by the high price projection tables in AEO 2009 (Table 3: Energy Prices by Sector and Source) (EIA, 2009). In 2008 dollars, the national average price of industrial electricity is $0.065/kWh.

B.4.1.3 Truck Transport Costs

The truck is divided into two parts: the cab that houses the engine and the tanker trailer which carries the fuel. The cab is a Class 8B truck with a service life of five years and, therefore, will have to be replaced six times over the study period. The truck uses conventional diesel fuel. The fuel economy for average loaded Class 8B trucks on the road in 2007 was 5.1 mpg (ORNL, 2007). The truck travels 35 miles from the bulk storage depot to each vehicle fueling station, servicing one fueling station per trip. Based on the required delivery schedule, the required number of trucks and trips is determined to estimate the capital, fixed, O&M, and fuel costs associated with truck transport.

The weight and materials of a tanker trailer are based on specifications of a petroleum trailer manufactured in 2008 (Hoffmann Transportation, 2009). To reduce curb weight (which, in turn, allows increased cargo weight) manufacturers use aluminum instead of steel for the construction of petroleum tanker trailers. This analysis assumes that aluminum accounts for the majority of the weight of the tanker trailer and that the tanker trailer has a 10 year service life.

Capital costs for the truck and 9,500 gallon tanker trailer are listed in **Table B-29**. Truck and trailer dealer information is used to obtain the costs for each of these components (Truck Paper, 2009). The costs shown in **Table B-29** are in 2009 dollars because that is basis year reported by the data source (Truck Paper, 2009). However, the LCC model normalizes the values for capital costs to a common year (2008).

Table B-29: Cost for Truck and Trailer

Capital Costs for Trucks & Trailers	Cost ($2009)
Heavy Duty Truck Class 8B: Assuming 2009 Volvo w/ Sleeper	$94,000
9,500 Gallon Tanker Trailer	$83,800

B.4.1.4 Vehicle Refueling Station Costs

The vehicle fueling station is defined as the fuel storage tank, fuel pumps, and dispensing stations. The emissions associated with energy used to transfer fuel from the underground storage tank and meter the fuel into the vehicles were estimated from the NETL Petroleum Baseline (NETL, 2008). Electricity is the primary power source for this motive action and emissions consistent with the power consumption are modeled using the U.S. power grid mix developed using the EPA eGRID database (EPA, 2007). Evaporative losses consistent with unloading the fuel from the tanker truck and refueling the vehicle at the station occur in this stage.

As with the bulk terminal, only O&M costs are considered for the refueling stations (i.e., the electricity and other associated operating costs are considered, however, the capital costs to build and decommission the refueling station are not included as the station is an existing facility). Electricity costs are estimated based on the AEO electricity price projections (EIA, 2009) for the United States during the study period.

B.4.1 Ethanol Transport Environmental

B.4.1.1 Domestic Pipeline Transport Environmental

The power requirement for pipeline transport of ethanol products is 0.025 kWh/ton-mile (Oregon DEQ, 2004 and NETL, 2008). Electrically powered pumps are used to move the fuels through the pipeline. It is assumed that there is no product loss during pipeline transport. The emissions

associated with the electricity used for pipeline transport of ethanol are modeled using fuel profile of the MROW electricity grid. The emissions associated with the electricity used for pipeline transport of gasoline are modeled using fuel profile of the average U.S. electricity grid.

B.4.1.2 *Bulk Storage Depot Environmental*

The bulk storage depot is an existing facility and thus its construction is not included in this analysis. The emissions associated with the electricity used for the storage depot is modeled in GaBi using the eGRID 2007 data (EPA, 2007). Because no operational electricity use data was found for a bulk storage depot, the energy use is assumed to be equivalent to that of a refueling station (fuel processing energy use only). The assumption is considered valid because of the similar energy consuming components operating in a bulk storage depot and in the fuel processing portions of a refueling station. The source of this data is provided in the refueling facility description.

B.4.1.3 *Tanker Truck Transport Environmental*

Both the construction and operation of tanker trucks are included within the study boundary. The operation of a tanker truck is representative of a Class 8B (>60,000 lbs gross vehicle weight) truck-trailer combination to transport fuel to the vehicle fueling station and then return (empty) to the bulk storage depot. Conventional diesel fuel production and related fuel combustion emissions are the only two variables modeled as part of this transport process. No material loss is assumed during transport due to the short distance traveled and the product being in the liquid state.

The trucks are powered by conventional diesel fuel, having a lower heating value (LHV) of 128,450 Btu/gal and a sulfur content of 200 parts per million [ppm] (which is representative of the sulfur content in diesel produced in 2005 (NETL, 2008)). The average distance traveled is 35 miles (one-way) from the bulk storage depot to the fueling stations. One fuel station is serviced per trip, and the empty truck returns to the bulk storage depot. The fuel economy for Class 8B trucks ranges from five mpg to eight mpg based on recent U.S. Department of Transportation statistics (ORNL, 2007). An average fuel economy of six mpg is applied to Class 8B heavy-duty trucks. This modeling assumption is consistent with the fuel economy parameter used other life cycle transportation models (ANL, 2009).

DOE's Argonne National Laboratory's (ANL) Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation Model (GREET), Version 1.8, was used as the primary reference source for modeling fuel combustion emissions for truck transport (ANL, 2009). The emission factors for Class 8B trucks are determined by the EPA Office of Transportation and Air Quality Mobile 6 model and then incorporated into the GREET model. A representative average operating truck for the study period is used.

The emission factors are based on two variables: (1) the fuel economy of the truck (expressed in mpg) and (2) emission factors in grams per MMBtu of fuel consumed. The result is multiplied by the round trip distance traveled to obtain the mass of combustion emissions per mass of fuel transported. No data are available for the differences in fuel economy between an empty and fully loaded Class 8B truck. This analysis assumes that the fuel economy of a Class 8B truck is constant during the delivery of cargo and the return trip to the point of origin.

B.4.1.4 *Vehicle Refueling Station Environmental*

As is the case with the bulk storage facility, the vehicle refueling facility is considered existing for this study. The vehicle fueling station is defined as the fuel storage tank, fuel pumps, and dispensing stations. A convenience store is not included in the process, as this component does not contribute to fuel processing.

The California Air Resource Board (CARB) regulations provide a requirement for the maximum emissions allowed for both the filling of the refueling station's storage tank and the refueling of the vehicle. For the refilling of the storage tank, there is a total organic emission factor of 0.48 pounds released per thousand gallons pumped (Nguyen, 1999). For the vehicle refueling, the hydrocarbon emission content allowed for either gasoline or diesel refueling is 0.20 grams per gallon of dispensed fuel (CARB, 2007).

Electricity supplied by the regional electrical grid is assumed to power all operations at the fueling station. The fuel profile of the MROW (Midwest Reliability Organization West) electricity grid is used to model the generation of fuel distribution. The cradle-to-gate environmental profiles for fuel production and electricity generation in the GaBi database are used to model the MROW grid mix (GaBi 4, 2009).

The environmental profile for the transport of ethanol-blended fuels is shown in **Table B-30**.

Table B-30: Environmental Profile for LC Stage #4 Delivery of Ethanol Blend

		E10	E85	Units/MJ of E10 or E85
Emissions to Air: Greenhouse Gases	CO_2	5.07E-04	6.06E-04	kg CO_2e
	CH_4	2.09E-05	2.59E-05	kg CO_2e
	N_2O	2.19E-06	3.07E-06	kg CO_2e
	Total	5.3E-04	6.35E-04	kg CO_2e
Emissions to Air: CAPs	NO_X	3.75E-06	3.10E-06	kg
	SO_2	3.26E-06	2.99E-06	kg
	CO	2.41E-06	3.04E-06	kg
	VOC	9.44E-05	1.22E-04	kg
	PM	2.92E-07	3.53E-07	kg
	Lead	1.22E-10	2.02E-10	kg
Emissions to Air: Species of Interest	Mercury	7.61E-12	1.10E-11	kg
	Ammonia	2.95E-09	3.84E-09	kg
	HCl	7.32E-09	1.04E-08	kg
	HF	3.86E-09	4.97E-09	kg
	NMVOC	9.44E-05	1.22E-04	kg
Emissions to Water	Aluminum	6.69E-10	8.95E-10	kg
	Ammonia	3.43E-09	4.52E-09	kg
	Heavy metals	1.09E-07	1.51E-07	kg
	HCl	2.50E-14	3.03E-14	kg
	Nitrate	3.50E-08	4.62E-08	kg
	Nitrogen	1.69E-10	2.23E-10	kg
	Phosphate	2.84E-10	3.68E-10	kg
	Phosphorus	9.82E-11	1.16E-10	kg
Water Withdrawal	Water In	2.72E-06	3.75E-06	m^3
	Water Out	8.16E-07	1.08E-06	m^3
	Net	1.90E-06	2.67E-06	m^3
Solid Waste	Heavy Metals to Soil	2.17E-09	2.63E-09	kg
	Solid Waste (Unspecified)	3.54E-10	5.01E-10	kg
Energy Containing Material Inputs	Crude oil	7.14E-03	8.50E-03	MJ
	Hard coal	1.40E-03	1.96E-03	MJ
	Lignite	1.24E-04	1.65E-04	MJ
	Natural gas	1.04E-03	1.34E-03	MJ
	Uranium	5.45E-04	7.30E-04	MJ
	Total	1.02E-02	1.27E-02	MJ

B.5 Life Cycle Stage #5: Vehicle Use

The boundary of LC Stage #5 includes operational emissions from the combustion of E10 and E85 fuels. This is the last LC stage in the study. Emissions from the construction of a passenger

vehicle are also included within the study boundary. Routine maintenance of the vehicle over the useful lifespan is excluded from the study boundary.

B.5.1 Vehicle Use Cost

This study uses the RSP approach, which means the cost paid by the final user of the ethanol fuel (in the form of E10 and E85 blends) is an output of the cost model, not an input. No other operating costs or capital costs are included within the boundaries of LC Stage #5 of this analysis. 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 vehicle use.

B.5.2 Vehicle Use Environmental

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 MOVES model calculates emissions of CO_2, VOCs, CO, NO_X, and PM from the combustion of conventional gasoline in passenger vehicles, and the 2008 analysis (Chester, 2008) compares the CH_4 and CAPs emissions from gasoline and ethanol combustion.

The fossil CO_2 emissions for E10 and E85 combustion are calculated by multiplying the share of gasoline in each fuel blend by the CO_2 emission factor for gasoline in the MOVES model (EPA, 2008). The biogenic CO_2 emissions for E10 and E85 combustion are calculated by determining the ethanol-bound carbon in each fuel blend and assuming that all carbon in ethanol is converted to CO_2 upon combustion. Similarly, SO_2 emissions from gasoline combustion are provided by the MOVES model and are apportioned to E10 and E85 according to the gasoline content of each ethanol blend. This analysis assumes that ethanol contains negligible sulfur and thus produces negligible SO_2 emissions upon combustion.

VOC, CO, NO_x, and PM emissions are not solely a function of the elemental composition of the combusted fuel, and thus the calculation of such emissions from E10 and E85 are not as straightforward as for CO_2 or SO_2. According to Chester (2008), the combustion of E85 has VOC emissions that are 27 percent higher than an equal volume of gasoline, CH_4 emissions that are 91 percent higher than an equal volume of gasoline, CO emissions that are 18 percent lower than an equal volume of gasoline, NO_x emissions that are 54 percent lower than an equal volume of gasoline, and PM emissions that are 34 percent lower than an equal volume of gasoline. These adjustments were used to develop emission factors for E10 and E85.

Combustion of fuels during LC Stage #5 has negligible burdens related to the consumption and quality of water. The materials for the construction of passenger vehicles are the only activity of LC Stage #5 that consume water and produce water emissions. The effects of airborne pollutant washout on water quality are considered secondary and are therefore outside the scope of the water use and water quality analysis.

The functional unit of this analysis (the combustion of 1 MJ of E10 or E85 fuel) normalizes the LC results to the production, delivery, and combustion of 1 MJ of fuel in LC Stage #5. The study period is 30 years, during which time the fuel efficiency of a passenger vehicle will change. However, since the functional unit normalizes the results of the analysis to 1 MJ of fuel, the fuel efficiency of the vehicle does not affect the LC results related to vehicle *operation*. However, the LC results related to vehicle

construction are a function of vehicle fuel efficiency because the materials used for vehicle construction are apportioned to the functional unit according to the total study period (30 years) and the total lifetime mileage and fuel use of the vehicle. The average passenger vehicle fuel efficiency in 2007 was given as 22.5 mpg by the ORNL 2007 Transportation Energy Data Book (ORNL, 2007). This value is used to represent the fuel efficiency of a 2012 passenger vehicle. The Energy Independence and Security Act of 2007 mandates an average passenger vehicle fuel efficiency of 35 mpg by the year 2020 (110th Congress, 2007). This value is used to represent the fuel efficiency of a 2042 passenger vehicle (the time frame of this study is 30 years, starting in the year 2012 and ending in the year 2042). The average of the assumed 2012 and 2042 vehicle efficiencies is 28.8 mpg, which is used as the average passenger vehicle fuel efficiency for this analysis.

The LCI results for LC Stage #5, Vehicle Use, are shown **Table B-31**.

Table B-31: Environmental Profile for LC Stage #5 Vehicle Use

		E10	E85	Units/MJ of E10 or E85
Emissions to Air: Greenhouse Gases	CO_2	7.30E-02	3.05E-02	kg CO_2e
	CO_2 (biogenic)	5.13E-03	4.76E-02	kg CO_2e
	CH_4	2.73E-04	3.42E-04	kg CO_2e
	N_2O	1.67E-03	1.67E-03	kg CO_2e
	Total	7.46E-02	2.93E-02	kg CO_2e
Emissions to Air: CAPs	NO_X	2.03E-04	1.25E-04	kg
	SO_2	2.01E-05	1.90E-05	kg
	CO	3.19E-03	3.80E-03	kg
	VOC	1.01E-06	1.01E-06	kg
	PM	5.12E-06	5.12E-06	kg
	Lead	3.88E-09	3.88E-09	kg
Emissions to Air: Species of Interest	Mercury	2.52E-10	2.52E-10	kg
	Ammonia	1.22E-08	1.22E-08	kg
	HCl	1.99E-07	1.99E-07	kg
	HF	1.24E-07	1.24E-07	kg
	NMVOC	1.01E-06	1.01E-06	kg
Emissions to Water	Aluminum	1.17E-08	1.17E-08	kg
	Ammonia	7.39E-08	7.39E-08	kg
	Heavy metals	8.38E-07	8.38E-07	kg
	HCl	1.58E-13	1.58E-13	kg
	Nitrate	4.22E-08	4.22E-08	kg
	Nitrogen	2.64E-10	2.64E-10	kg
	Phosphate	6.12E-09	6.12E-09	kg
	Phosphorus	6.58E-10	6.58E-10	kg
Water Withdrawal	Water In	4.11E-05	4.11E-05	m^3
	Water Out	1.35E-05	1.35E-05	m^3
	Net	2.76E-05	2.76E-05	m^3
Solid Waste	Heavy Metals to Soil	2.55E-08	2.55E-08	kg
	Solid Waste	9.58E-10	9.58E-10	kg
Energy Containing Material Inputs	Crude Oil	1.82E-02	1.82E-02	MJ
	Hard Coal	2.81E-02	2.81E-02	MJ
	Lignite	3.01E-03	3.01E-03	MJ
	Natural Gas	1.43E-02	1.43E-02	MJ
	Uranium	9.65E-03	9.65E-03	MJ
	Total	7.32E-02	7.32E-02	MJ

APPENDIX C: DETAILED ASSUMPTIONS FOR GASOLINE LC STAGES

This analysis models the production of gasoline in parallel to the production of ethanol. Gasoline is blended with ethanol in LC Stage #4 (at the bulk loading terminal). This appendix provides details on the modeling of gasoline, from cradle-to-gate, beginning with crude oil extraction and ending with distribution operations in LC Stage #4.

C.1 Life Cycle Stage #1: Raw Material Acquisition

The boundary LC Stage #1 begins with the extraction of crude oil. The boundary ends with the preparation of crude oil for transport to a petroleum refinery. The crude oil data modeled in this analysis is representative of the 2005 supply mix of U.S. gasoline supply, which includes a mix of gasoline refined in the U.S. and gasoline imported from foreign refineries (NETL, 2008). This analysis tracks only environmental flows in LC Stage #1 of gasoline production; cost flows are not tracked until LC Stage #4 of the cost model.

C.1.1 Crude Oil Acquisition

This analysis uses the 2005 U.S. national profile for petroleum products, as detailed in the NETL Petroleum Baseline Study (NETL, 2008), to represent the acquisition of crude oil for gasoline production. Additionally, the NETL LCI of Petroleum-Based Transportation Fuel Sold or Distributed in the United States (NETL, 2009a) includes an expanded inventory of LC metrics, including CAPs, other air emissions of concern, water use, and water quality. The results of the Petroleum Baseline Study (NETL, 2008) and the expanded LCI of petroleum fuels (NETL, 2009a) are the basis for modeling crude oil acquisition for this study. The crude oil supply to U.S. transportation fuels and other refinery products is depicted in **Figure C-1.**

The key assumptions for crude oil acquisition are summarized below. For more details on the data and assumptions for the pathways to the production of petroleum products, see the NETL Petroleum Baseline Study (NETL, 2008) and the NETL LCI of Petroleum-Based Transportation Fuel Sold or Distributed in the United States (NETL, 2009a).

C.1.1.1 *Crude Oil for Domestic Refined Fuels*

U.S. petroleum refineries had a 2005 feedstock mix of 62 percent imported crude oil, 32 percent domestic crude oil, and six percent NGL (natural gas liquids) and unfinished oils, as reported by refiners to EIA. **Table C-1** shows the quantities in thousand barrels per day (MBPD) of crude oil imported by the United States from each of the top 10 countries, as well as the other inputs to U.S. refineries in 2005.

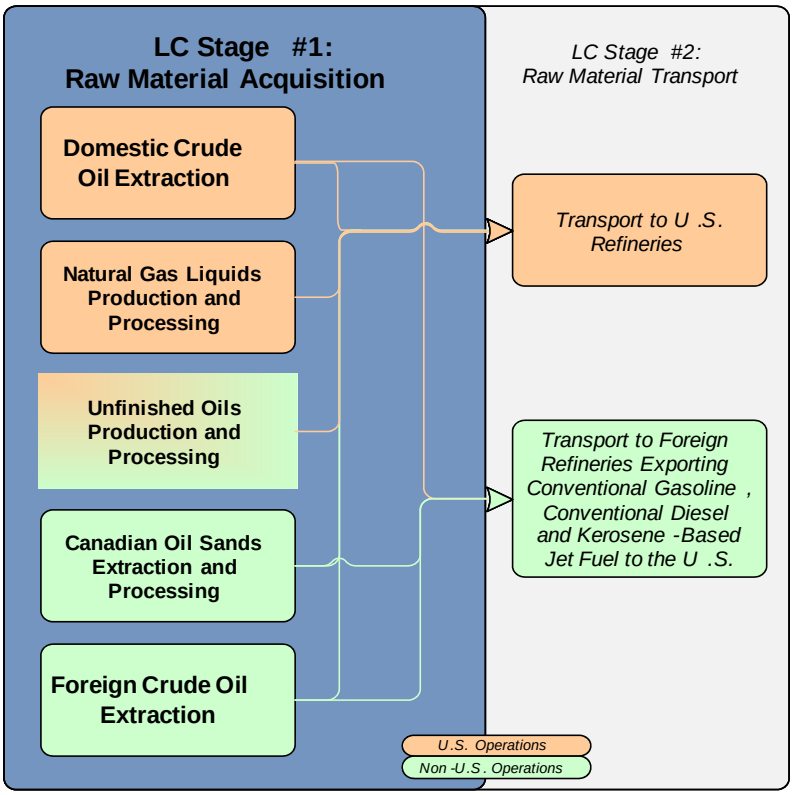

Figure C-1: Flow Diagram of Raw Material Acquisition Activities

Table C-1: Source and Quantity of Feedstock Input to U.S. Refineries in 2005 (EIA, 2008)

Feedstock Source	Input to U.S. Refineries (MBPD)
Domestic Crude Oil	5,140
Canada	1,630
Mexico	1,550
Other Imports	1,450
Saudi Arabia	1,440
Venezuela	1,240
Nigeria	1,080
Iraq	522
Angola	455
Ecuador	276
Algeria	228
Kuwait	222
NGL and Unfinished Oils	1,000
Total	**16,200**

C.1.1.2 *Crude Oil for Foreign Refined Fuels*

In addition to petroleum products from domestic refineries, the U.S. imports refined petroleum products. Upstream emissions for those materials imported to the United States were estimated and added to the U.S. refining upstream profile to gain a comprehensive view of the emissions consistent with use of liquid fuels in the United States in 2005 (NETL, 2008).

Crude oil was refined in and finished products were exported from a distinct set of foreign countries for each fuel-gasoline, diesel, and jet fuel. Feedstock extraction modeling is conducted and results are compiled for each of these sets of foreign countries (NETL, 2008).

C.1.2 Crude Oil Acquisition Environmental Profiles

The environmental profile for the extraction of crude oil, representative of the 2005 U.S. national average supply, is shown in **Table C-2**.

Table C-2: Environmental Profile per 1 m^3 of Crude Oil Extraction

		National Average, 2005	Units/m^3 of Crude Oil
Emissions to Air: Greenhouse Gases	CO_2	188	kg CO_2e
	CH_4	2.02E-03	kg CO_2e
	N_2O	3.64E-05	kg CO_2e
	Total	188	kg CO_2e
Emissions to Air: CAPs	NO_X	5.59E-01	kg
	SO_2	8.86E-01	kg
	CO	3.90E-01	kg
	VOC	8.40E-02	kg
	PM	4.12E-03	kg
	Lead	4.65E-05	kg
Emissions to Air: Species of Interest	Mercury	3.43E-07	kg
	Ammonia	3.14E-03	kg
	HCl	3.34E-04	kg
	HF	5.26E-05	kg
	NMVOC	6.78E-01	kg
Emissions to Water	Aluminum	1.60E-04	kg
	Ammonia	3.84E-03	kg
	Heavy metals	3.49E-02	kg
	HCl	1.09E-07	kg
	Nitrate	3.45E-04	kg
	Nitrogen	1.91E-06	kg
	Phosphate	8.62E-06	kg
	Phosphorus	1.64E-03	kg
Water Withdrawal	Water In	3.30E-01	m^3
	Water Out	1.71E-01	m^3
	Net	1.59E-01	m^3
Solid Waste	Heavy Metals to Soil	9.58E-03	kg
	Solid Waste (Unspecified)	negligible	kg
	Total	9.58E-03	kg
Energy Containing Material Inputs	Crude oil	37,000	MJ
	Hard coal	65.0	MJ
	Lignite	12.2	MJ
	Natural gas	2,650	MJ
	Uranium	23.9	MJ
	Total	39,700	MJ

All costs related to the acquisition of crude oil are assumed to be accounted for in the delivered cost of gasoline at the entry gate of the bulk loading terminal (LC Stage #4).

C.2 Life Cycle Stage #2: Raw Material Transport

LC Stage #2 includes transport of all crude oil to a petroleum refinery. This analysis tracks only environmental flows in LC Stage #2 of gasoline production; cost flows are not tracked until LC Stage #4 of the cost model.

C.2.1 Crude Oil Transport

The 2005 U.S. national profile for petroleum products, as detailed in the NETL Petroleum Baseline Study (NETL, 2008), was used to represent the acquisition of crude oil for gasoline production. The national average includes the transport of crude oil from domestic sources to domestic refineries, the transport of crude oil from foreign sources to domestic refineries, and the transport of crude oil from foreign sources to foreign refineries. These three crude oil transport scenarios are discussed below.

C.2.1.1 *Crude Oil from Foreign Sources to Domestic Refineries*

For all foreign crude sources to U.S. refineries, the crude is assumed to be transported 100 miles via pipeline to an ocean port or U.S. border. The energy intensity for pipeline transport is assumed to be 260 British thermal units (Btu) per ton-mile (Wang, 2008), and electricity is assumed to be the power source. The emissions from electricity generation used for pipeline operation are estimated using emissions from the U.S. power grid as a surrogate profile for that of foreign countries. This is a data limitation, but the overall impact to the LC emissions is expected to be minimal.

The energy requirement for transporting crude oil via tanker is calculated by multiplying the quantity shipped by the distance traveled, in nautical miles, and the energy intensity of transport. The return trip with petroleum products is assumed to require the same amount of energy. The values are summed for each of the different import sources and the emissions associated with consumption of that quantity of energy (as heavy fuel oil) are determined.

C.2.1.2 *Crude Oil from Domestic Sources to Domestic Refineries*

Crude oil transport within the United States is accomplished by a mix of transportation modes, including pipeline, water carrier, rail, and truck. The Oak Ridge National Laboratory Transportation Energy Data Book (ORNL, 2007), Table 2.4, outlines the domestic consumption of transportation energy by mode and fuel type. These data were used to determine the fuel powering the aforementioned transportation operations. Natural gas and electricity are the primary fuels for the operation of natural gas and petroleum pipelines, respectively (Oregon DEQ, 2004). Diesel is the primary fuel source for freight railroad operations (Oregon DEQ, 2004). Water carriers transporting freight are powered using diesel and residual fuel oil (30.5 percent diesel and 69.5 percent residual fuel oil on an energy basis). Medium/heavy trucks are powered primarily (90 percent) using diesel and petroleum tanker trucks are assumed to be powered exclusively using diesel (Oregon DEQ, 2004; ORNL, 2007).

C.2.1.3 Crude Oil from Foreign Sources to Foreign Refineries

It is assumed that all countries exporting a significant share of refined petroleum products to the U.S. have 100 miles of pipeline transport from the crude oil extraction site to a petroleum refinery. The energy intensity for pipeline transport is assumed to be 260 Btu/ton-mile (Wang, 2008), and electricity is assumed to be the power source. The emissions associated with pipeline transport are estimated using emissions from the U.S. power grid as a surrogate profile for that of foreign countries. This is noted as a data limitation but the overall impact to the LC emissions is expected to be minimal.

Canada, the Virgin Islands, and South Korea import significant quantities of foreign crude for refinery processing. It was assumed that all crude imports to Canada from the United States are by pipeline, while the balance of crude imports to Canada is by ocean freight. Transport of crude oil to the Virgin Islands and South Korea is assumed to be 100 percent by ocean freight. The Portworld distance calculator (Portworld, 2008) was used in combination with EIA data to determine port-to-port travel distances for ocean freight crude oil shipments. The port-to-port distance calculations included the constraint that waterways such as the Panama Canal, Suez Canal, and Bosporus Strait are too narrow to accommodate crude oil tankers (The Economist, 2009). The weighted average travel distance traveled by ocean freighter determined for each country is shown in **Table C-3**. Crude oil mix transport within Canada, the Virgin Islands, and South Korea is assumed to be negligible because refineries receiving crude are located at a port.

Table C-3: One-Way Travel Distance Assumptions Associated with Ocean Tanker Transport of Foreign Crude to Foreign Refineries/Ports

Receiving Country	Weighted Average Travel Distance One Way (Nautical Miles)*
Canada	4,970
Virgin Islands	1,730
South Korea	6,190

* Weighted average based on assumed waterborne import volumes only.

The environmental inventory data for the transport of crude oil from the site of extraction to petroleum refineries is shown in **Table C-4**.

Table C-4: Environmental Profile for LC Stage #2 Crude Oil Transport for the Production of Petroleum Fuel

		National Average, 2005	Units/m^3 of Crude Oil
Emissions to Air: Greenhouse Gases	CO_2	71.3	kg CO_2e
	CH_4	2.25	kg CO_2e
	N_2O	1.13E-01	kg CO_2e
	Total	73.6	kg CO_2e
Emissions to Air: CAPs	NOX	1.10	kg
	SO2	8.12E-01	kg
	CO	2.10E-01	kg
	VOC	9.23E-02	kg
	PM	5.50E-04	kg
	Lead	5.34E-06	kg
Emissions to Air: Species of Interest	Mercury	3.15E-07	kg
	Ammonia	6.72E-04	kg
	HCl	3.55E-04	kg
	HF	1.85E-04	kg
	NMVOC	4.80E-01	kg
Emissions to Water	Aluminum	4.06E-05	kg
	Ammonia	6.98E-05	kg
	Heavy Metals	7.08E-03	kg
	HCl	2.77E-09	kg
	Nitrate	3.97E-04	kg
	Nitrogen	5.96E-06	kg
	Phosphate	1.22E-05	kg
	Phosphorus	4.95E-05	kg
Water Withdrawal	Water In	9.08E-02	m^3
	Water Out	5.57E-02	m^3
	Net	3.50E-02	m^3
Solid Waste	Heavy Metals to Soil	2.42E-04	kg
	Solid Waste (Unspecified)	2.16E-05	kg
Energy Containing Material Inputs	Crude oil	880	MJ
	Hard coal	64.6	MJ
	Lignite	6.88	MJ
	Natural gas	89.6	MJ
	Uranium	32.7	MJ
	Total	1,070	MJ

C.3 Life Cycle Stage #3: Petroleum Refinery

The boundary of LC Stage #3 begins at the entrance to the energy conversion facility with the receipt of feedstock material and ends at the entrance to the pipeline used to transport the liquid fuel to the bulk fuel storage depot. This LC stage also includes all CCS equipment and operations, beginning with the capture of CO_2 in the energy conversion facility and ending with sequestration in an underground geologic structure. This analysis tracks only environmental flows in LC Stage #3 of gasoline production; cost flows are not tracked until LC Stage #4 of the cost model used in this analysis.

C.3.1 Petroleum Refinery Operation Processes

The characteristics of gasoline production at a petroleum refinery are based on the 2005 U.S. petroleum supply chain as described by NETL's Petroleum Baseline Model (NETL, 2008). Additionally, the NETL LCI of Petroleum-Based Transportation Fuel Sold or Distributed in the United States (NETL, 2009a) includes an expanded inventory of LC metrics, including CAPs, other air emissions of concern, water use, and water quality. The results of the Petroleum Baseline Study (NETL, 2008) and the expanded LCI of petroleum fuels (NETL, 2009a) are the basis for modeling gasoline production for this study.

The environmental profile for the production of gasoline that is representative of the U.S. 2005 national average supply is shown in **Table C-5**.

Table C-5: Environmental Profile for LC Stage #3 Refinery Production of Gasoline

		National Average, 2005	Units/MJ Gasoline
Mass Emitted to Atmosphere	CO_2	2.63	kg CO2e
	CH_4	3.19E-02	kg CO2e
	N_2O	1.25E-02	kg CO2e
	Total	2.67	kg CO2e
Mass of Pollutant Emitted to Atmosphere	NO_X	7.15E-04	kg
	SO_2	1.79E-03	kg
	CO	2.37E-04	kg
	VOC	1.31E-04	kg
	PM	5.59E-05	kg
	Lead	2.80E-08	kg
Mass of Pollutant Emitted to Atmosphere	Mercury	5.39E-09	kg
	Ammonia	1.57E-06	kg
	HCl	7.79E-06	kg
	HF	1.02E-06	kg
	NO	7.85E-12	kg
	NMVOC	1.31E-04	kg
Mass Emitted to Body of Water	Aluminum	1.65E-06	kg
	Ammonia	1.35E-06	kg
	Heavy metals	2.00E-02	kg
	HCl	4.64E-11	kg
	Nitrate	8.62E-06	kg
	Nitrogen	8.05E-10	kg
	Phosphate	3.47E-03	kg
	Phosphorus	2.57E-08	kg
Volume of Water	Water In	1.93E-02	m^3
	Water Out	2.06E-03	m^3
	Net	1.73E-02	m^3
Mass Emitted	Heavy Metals to Soil	1.51E-06	kg
	Solid Waste (Unspecified)	1.61E-06	kg
	Total	3.12E-06	kg
Energy Containing Materials	Crude Oil	1.18E-02	MJ
	Hard Coal	5.63E-02	MJ
	Lignite	5.15E-03	MJ
	Natural Gas	1.79E-01	MJ
	Uranium	3.18E-02	MJ
	Total	2.84E-01	MJ

C.4 Life Cycle Stage #4: Gasoline Transport

LC Stage #4 begins where finished gasoline exits foreign and domestic refineries, and ends with the fueling of a passenger vehicle. This stage includes product transport to bulk storage facilities and subsequent transport to refueling terminals.

LC Stage #4 is the first point in the cost model where gasoline costs are tracked. The cost model of this analysis assumes that the cost of gasoline received at the bulk loading terminal (approximately $2.15/gallon) accounts for all upstream costs of the gasoline life cycle; thus, to avoid the double counting of costs, the cost model does not track costs for gasoline in LC Stage #1, LC Stage #2, and LC Stage #3.

Gasoline is transported from the refinery to a bulk loading terminal by pipeline (NETL, 2008). At the bulk loading terminal, gasoline is mixed with ethanol in E10 or E85 compositions. The gasoline and ethanol supply chains merge at the bulk loading terminal, and the assumptions for subsequent transport of E10 and E85 are detailed in the assumptions for the ethanol life cycle.

The construction of existing infrastructure is not included in this analysis. Existing infrastructure for this LC stage includes pipelines for transport of gasoline fuel to a bulk loading facility, the gasoline storage tanks and associated equipment at the bulk loading facility, and other equipment used for the distribution of gasoline.

C.5 Life Cycle Stage #5: Vehicle Use

The boundary of LC Stage #5 includes operational emissions from the combustion of E10 and E85 fuels. The gasoline and ethanol streams of this analysis merge at the bulk loading terminal in LC Stage #4 of this analysis; details for LC Stage #5 are provided in the previous appendix on the ethanol life cycle.

APPENDIX D: LIFE CYCLE METRICS

Table D-1 shows the full list of metrics included in this analysis.

Table D-1: Comprehensive List of Life Cycle Environmental and Cost Metrics

Category	Primary Inventory Data*	Reporting Metric per Functional Unit & Unit Process Reference Flow
Greenhouse Gases	• Carbon Dioxide (CO_2) • Methane (CH_4) • Nitrous Oxide (N_2O) • Other significant GHGs as identified/listed by IPCC and adopted by the U.S. EPA.	• Mass of Pollutant Emitted to Atmosphere • Mass Emitted to Atmosphere
Criteria Air Pollutants	• Nitrogen Oxides (NO_X) • Sulfur Dioxide (SO_2) • Carbon Monoxide (CO) • Ozone (O_3) • Particulate Matter less than or equal to 10 microns (PM10) • Lead (Pb)	• Mass Emitted to Atmosphere
Species of Interest	• Mercury • Ammonia • Hydrogen Chloride • Hydrogen Fluoride • Non-Methane VOCs (>=1%) • Other Heavy Metal (>=1%)	• Mass Emitted to Atmosphere
Solid Waste	• Heavy Metals to Soil (>=1%) • Solid Waste (unspecified)	• Mass Emitted
Raw Materials	• Coal • Crude Oil • Natural Gas • Uranium • Unconventional Fossil Resources • Renewable Resources	• Energy Content of Material
Water Emissions	• Aluminum • Ammonium/ammonia • Heavy Metals (>=1% by mass) • Hydrogen Chloride • Nitrate • Nitrogen • Phosphate • Phosphorous	• Mass Emitted to Body of Water
Water Withdrawal and Consumption	• Volume of Water Withdrawn from Surface or Groundwater Sources • Volume of Water Returned to Receiving Body of Water	• Volume of Water Withdrawn • Volume of Water Consumed
Land Use	• Area of Land Type Changed • Land Type (prior to use) • Land Type (during use) • Land Type (post use)	• Area of Land Type Changed • Land Type (prior to use) • Land Type (during use) • Land Type (post use)
Life Cycle Cost	• Capital Costs • O&M Costs • Other Expenses & By-Product Income	• RSP (Required Selling Price) • Net Present Value

* Reported per unit process when greater than one percent by reporting metric (mass, energy content, etc.).

APPENDIX E: CO-PRODUCT ALLOCATION BETWEEN GRAIN AND STOVER

It is well understood that corn grain is a valuable food crop that can also be used for the production of fuels such as ethanol. Therefore, it is necessary to allocate the resources and emissions used for growing corn between stover and grain. This analysis applies an energy-based allocation method to corn stover. The percent of resources and emissions allocated to each product is determined by their relative heating values (NETL, 2009c; Pimentel and Patzek, 2005; PSU, 2009) factored by their relative yields (Shapouri *et al.,* 2002; Brechbill, 2008). Using energy as a basis for the co-product allocation between corn grain and stover, 59 percent of the shared process emissions are allocated to stover and 41 percent are allocated to grain. (If mass-based allocation is used, 56 percent of resources and emissions are allocated to stover and 44 percent to grain.) These calculations are summarized in the following table.

Table E-1: Co-product allocation between corn grain and corn stover

Co-product	**Yield** kg/acre-year (lb/acre-year)	**Heating Value** MJ/kg (Btu/lb)	**Energy (Yield * Heating Value)** MJ/acre-year (MMBtu/acre-year)	**Energy-based allocation factors**
Corn grain	2,980 (6,570)	15.5 (6,643)	46,200 (43.8)	0.41
Corn stover	3,856 (8,501)	17.1 (7,332)	65,900 (62.5)	0.59
Total	6,835 (15,069)	N/A	112,000 (106)	1.00

References

Shapouri, H., J.A. Duffield, M. Wang. *The Energy Balance of Corn Ethanol: An Update.* U.S. Department of Agriculture, Office of the Chief Economist, Office of Energy Policy and New Uses. Agricultural Report No. 813. July 2002.

Brechbill, S. and Tyner, W. (2008). *The Economics of Biomass Collection, Transportation, and Supply to Indiana Cellulosic and Electric Utility Facilities.* Working Paper #08-03. Department of Agricultural Economics, Purdue University.

APPENDIX F: DETAILED RESULTS

This appendix shows cradle-to-grave LC results for the 18 pathways of this analysis. These results include greenhouse gas emissions, resource energy consumption, net water withdrawal, criteria air pollutants, other air emissions of concern, transformed land area, and greenhouse gas emissions from transformed land. All results in this appendix are expressed on the basis of the delivery of 1 MJ of E10 or E85.

The results for greenhouse gas emissions for the E10 and E85 pathways are shown in **Table F-1** and **Table F-2**, respectively. These tables show the results for each life cycle stage. Values for CO_2, N_2O and CH_4 are expressed in terms of carbon dioxide equivalents (CO_2e).

Table F-1: Greenhouse Gas Emissions in kg CO_2e per 1 MJ of E10 Fuel

		LC Stage #1	LC Stage #2	LC Stage #3	LC Stage #4	LC Stage #5	Total
Dry Grind Corn (E10)	Fossil CO_2	5.55E-03	1.32E-03	9.14E-03	2.35E-04	7.30E-02	8.92E-02
	N_2O (CO_2e)	9.84E-04	2.00E-06	3.79E-05	9.50E-07	1.67E-03	2.69E-03
	CH_4 (CO_2e)	1.67E-03	3.99E-05	1.50E-04	7.40E-06	2.73E-04	2.14E-03
	Biogenic CO_2	-6.04E-03	0	1.05E-03	0	5.13E-03	1.37E-04
	Net CO_2e	2.17E-03	1.36E-03	1.04E-02	2.44E-04	8.01E-02	**9.42E-02**
Dry Grind Corn w/ oil extraction (E10)	Fossil CO_2	5.60E-03	1.32E-03	8.85E-03	2.35E-04	7.30E-02	8.90E-02
	N_2O (CO_2e)	1.06E-03	2.01E-06	3.43E-05	9.50E-07	1.67E-03	2.77E-03
	CH_4 (CO_2e)	1.67E-03	4.00E-05	1.42E-04	7.40E-06	2.73E-04	2.13E-03
	Biogenic CO_2	-6.43E-03	0	3.42E-03	0	5.13E-03	2.12E-03
	Net CO_2e	1.90E-03	1.36E-03	1.24E-02	2.44E-04	8.01E-02	**9.60E-02**
Dry Grind Corn w/ oil extraction and CCS (E10)	Fossil CO_2	5.59E-03	1.32E-03	8.12E-03	2.35E-04	7.30E-02	8.83E-02
	N_2O (CO_2e)	1.04E-03	2.01E-06	3.58E-05	9.50E-07	1.67E-03	2.75E-03
	CH_4 (CO_2e)	1.67E-03	4.00E-05	1.51E-04	7.40E-06	2.73E-04	2.14E-03
	Biogenic CO_2	-6.43E-03	0	2.32E-03	0	5.13E-03	1.03E-03
	Net CO_2e	1.88E-03	1.36E-03	1.06E-02	2.44E-04	8.01E-02	**9.42E-02**
Biochem Stover w/ FBC cogen (E10)	Fossil CO_2	5.79E-03	1.34E-03	6.12E-03	2.35E-04	7.30E-02	8.65E-02
	N_2O (CO_2e)	1.25E-03	2.19E-06	3.08E-05	9.50E-07	1.67E-03	2.95E-03
	CH_4 (CO_2e)	1.67E-03	4.24E-05	6.81E-05	7.40E-06	2.73E-04	2.06E-03
	Biogenic CO_2	-1.25E-02	0	7.02E-03	0	5.13E-03	-3.79E-04
	Net CO_2e	2.17E-03	1.36E-03	1.04E-02	2.44E-04	8.01E-02	**9.42E-02**
Biochem Switchgrass w/ FBC cogen (E10)	Fossil CO_2	6.39E-03	1.36E-03	5.61E-03	2.35E-04	7.30E-02	8.66E-02
	N_2O (CO_2e)	2.68E-03	2.31E-06	2.88E-05	9.50E-07	1.67E-03	4.38E-03
	CH_4 (CO_2e)	1.69E-03	4.40E-05	5.65E-05	7.40E-06	2.73E-04	2.07E-03
	Biogenic CO_2	-1.35E-02	0	8.35E-03	0	5.13E-03	2.41E-06
	Net CO_2e	-2.71E-03	1.40E-03	1.40E-02	2.44E-04	8.01E-02	**9.30E-02**
Biochem Stover w/ gasifier cogen (E10)	Fossil CO_2	5.79E-03	1.34E-03	4.93E-03	2.35E-04	7.30E-02	8.53E-02
	N_2O (CO_2e)	1.25E-03	2.19E-06	2.61E-05	9.50E-07	1.67E-03	2.95E-03
	CH_4 (CO_2e)	1.67E-03	4.24E-05	2.98E-05	7.40E-06	2.73E-04	2.03E-03
	Biogenic CO_2	-1.25E-02	0	6.34E-03	0	5.13E-03	-1.05E-03
	Net CO_2e	-3.81E-03	1.39E-03	1.13E-02	2.44E-04	8.01E-02	**8.92E-02**
Biochem Switchgrass w/ gasifier cogen (E10)	Fossil CO_2	6.39E-03	1.36E-03	4.10E-03	2.35E-04	7.30E-02	8.51E-02
	N_2O (CO_2e)	2.68E-03	2.31E-06	2.29E-05	9.50E-07	1.67E-03	4.37E-03
	CH_4 (CO_2e)	1.69E-03	4.40E-05	8.25E-06	7.40E-06	2.73E-04	2.03E-03
	Biogenic CO_2	-1.35E-02	0	7.19E-03	0	5.13E-03	-1.16E-03
	Net CO_2e	-2.72E-03	1.40E-03	1.13E-02	2.44E-04	8.01E-02	**9.03E-02**
Thermochem Stover (E10)	Fossil CO_2	5.78E-03	1.34E-03	7.34E-03	2.35E-04	7.30E-02	8.77E-02
	N_2O (CO_2e)	1.24E-03	2.18E-06	3.54E-05	9.50E-07	1.67E-03	2.95E-03
	CH_4 (CO_2e)	1.67E-03	4.23E-05	8.90E-05	7.40E-06	2.73E-04	2.08E-03
	Biogenic CO_2	-1.25E-02	0	7.15E-03	0	5.13E-03	-1.92E-04
	Net CO_2e	-3.77E-03	1.38E-03	1.46E-02	2.44E-04	8.01E-02	**9.25E-02**
Thermochem Switchgrass (E10)	Fossil CO_2	6.23E-03	1.35E-03	7.34E-03	2.35E-04	7.30E-02	8.81E-02
	N_2O (CO_2e)	2.38E-03	2.26E-06	3.54E-05	9.50E-07	1.67E-03	4.09E-03
	CH_4 (CO_2e)	1.69E-03	4.33E-05	8.90E-05	7.40E-06	2.73E-04	2.10E-03
	Biogenic CO_2	-1.19E-02	0	7.21E-03	0	5.13E-03	3.95E-04
	Net CO_2e	-1.64E-03	1.39E-03	1.47E-02	2.44E-04	8.01E-02	**9.47E-02**

Table F-2: Greenhouse Gas Emissions in kg CO_2e per 1 MJ of E85 Fuel

		LC Stage #1	LC Stage #2	LC Stage #3	LC Stage #4	LC Stage #5	Total
Dry Grind Corn (E85)	Fossil CO_2	7.60E-03	6.99E-04	2.15E-02	2.71E-04	3.05E-02	6.06E-02
	N_2O (CO_2e)	9.50E-03	1.66E-06	4.48E-05	1.45E-06	1.67E-03	1.12E-02
	CH_4 (CO_2e)	8.88E-04	2.67E-05	6.56E-04	8.59E-06	3.42E-04	1.92E-03
	Biogenic CO_2	-6.05E-02	0	1.05E-02	0	4.76E-02	-2.47E-03
	Net CO_2e	-4.26E-02	7.27E-04	3.28E-02	2.81E-04	8.00E-02	**7.12E-02**
Dry Grind Corn w/ oil extraction (E85)	Fossil CO_2	8.04E-03	7.06E-04	1.87E-02	2.71E-04	3.05E-02	5.81E-02
	N_2O (CO_2e)	1.03E-02	1.71E-06	9.60E-06	1.45E-06	1.67E-03	1.20E-02
	CH_4 (CO_2e)	9.01E-04	2.73E-05	5.71E-04	8.59E-06	3.42E-04	1.85E-03
	Biogenic CO_2	-6.44E-02	0	3.43E-02	0	4.76E-02	1.74E-02
	Net CO_2e	-4.52E-02	7.35E-04	5.35E-02	2.81E-04	8.00E-02	**8.93E-02**
Dry Grind Corn w/ oil extraction and CCS (E85)	Fossil CO_2	7.94E-03	7.06E-04	1.13E-02	2.71E-04	3.05E-02	5.07E-02
	N_2O (CO_2e)	1.01E-02	1.71E-06	2.40E-05	1.45E-06	1.67E-03	1.18E-02
	CH_4 (CO_2e)	8.98E-04	2.73E-05	6.70E-04	8.59E-06	3.42E-04	1.95E-03
	Biogenic CO_2	-6.44E-02	0	2.33E-02	0	4.76E-02	6.44E-03
	Net CO_2e	-4.55E-02	7.35E-04	3.53E-02	2.81E-04	8.00E-02	**7.09E-02**
Biochem Stover w/ FBC cogen (E85)	Fossil CO_2	9.97E-03	9.51E-04	-8.69E-03	2.71E-04	3.05E-02	3.30E-02
	N_2O (CO_2e)	1.22E-02	3.59E-06	-2.58E-05	1.45E-06	1.67E-03	1.38E-02
	CH_4 (CO_2e)	9.36E-04	5.17E-05	-1.65E-04	8.59E-06	3.42E-04	1.17E-03
	Biogenic CO_2	-1.26E-01	0	7.03E-02	0	4.76E-02	-7.64E-03
	Net CO_2e	-1.02E-01	1.01E-03	6.14E-02	2.81E-04	8.00E-02	**4.03E-02**
Biochem Switchgrass w/ FBC cogen (E85)	Fossil CO_2	1.60E-02	1.12E-03	-1.39E-02	2.71E-04	3.05E-02	3.40E-02
	N_2O (CO_2e)	2.65E-02	4.74E-06	-4.59E-05	1.45E-06	1.67E-03	2.81E-02
	CH_4 (CO_2e)	1.13E-03	6.74E-05	-2.82E-04	8.59E-06	3.42E-04	1.26E-03
	Biogenic CO_2	-1.35E-01	0	8.37E-02	0	4.76E-02	-3.82E-03
	Net CO_2e	-9.15E-02	1.19E-03	6.95E-02	2.81E-04	8.00E-02	**5.95E-02**
Biochem Stover w/ gasifier cogen (E85)	Fossil CO_2	9.97E-03	9.51E-04	-2.07E-02	2.71E-04	3.05E-02	2.10E-02
	N_2O (CO_2e)	1.22E-02	3.59E-06	-7.32E-05	1.45E-06	1.67E-03	1.38E-02
	CH_4 (CO_2e)	9.36E-04	5.17E-05	-5.50E-04	8.59E-06	3.42E-04	7.90E-04
	Biogenic CO_2	-1.26E-01	0	6.36E-02	0	4.76E-02	-1.44E-02
	Net CO_2e	-1.02E-01	1.01E-03	4.23E-02	2.81E-04	8.00E-02	**2.11E-02**
Biochem Switchgrass w/ gasifier cogen (E85)	Fossil CO_2	1.60E-02	1.12E-03	-2.89E-02	2.71E-04	3.05E-02	1.89E-02
	N_2O (CO_2e)	2.65E-02	4.74E-06	-1.06E-04	1.45E-06	1.67E-03	2.81E-02
	CH_4 (CO_2e)	1.13E-03	6.74E-05	-7.65E-04	8.59E-06	3.42E-04	7.79E-04
	Biogenic CO_2	-1.35E-01	0	7.21E-02	0	4.76E-02	-1.55E-02
	Net CO_2e	-9.15E-02	1.19E-03	4.23E-02	2.81E-04	8.00E-02	**3.23E-02**
Thermochem Stover (E85)	Fossil CO_2	9.90E-03	9.40E-04	3.48E-03	2.71E-04	3.05E-02	4.51E-02
	N_2O (CO_2e)	1.21E-02	3.56E-06	1.99E-05	1.45E-06	1.67E-03	1.38E-02
	CH_4 (CO_2e)	9.26E-04	5.13E-05	4.43E-05	8.59E-06	3.42E-04	1.37E-03
	Biogenic CO_2	-1.25E-01	0	7.16E-02	0	4.76E-02	-5.77E-03
	Net CO_2e	-1.02E-01	9.95E-04	7.52E-02	2.81E-04	8.00E-02	**5.45E-02**
Thermochem Switchgrass (E85)	Fossil CO_2	1.44E-02	1.05E-03	3.48E-03	2.71E-04	3.05E-02	4.96E-02
	N_2O (CO_2e)	2.35E-02	4.28E-06	1.99E-05	1.45E-06	1.67E-03	2.52E-02
	CH_4 (CO_2e)	1.07E-03	6.14E-05	4.43E-05	8.59E-06	3.42E-04	1.53E-03
	Biogenic CO_2	-1.20E-01	0	7.22E-02	0	4.76E-02	1.11E-04
	Net CO_2e	-8.07E-02	1.11E-03	7.58E-02	2.81E-04	8.00E-02	**7.65E-02**

The resource energy profile for each pathway is shown in **Figure F-1** and **Table F-3**.

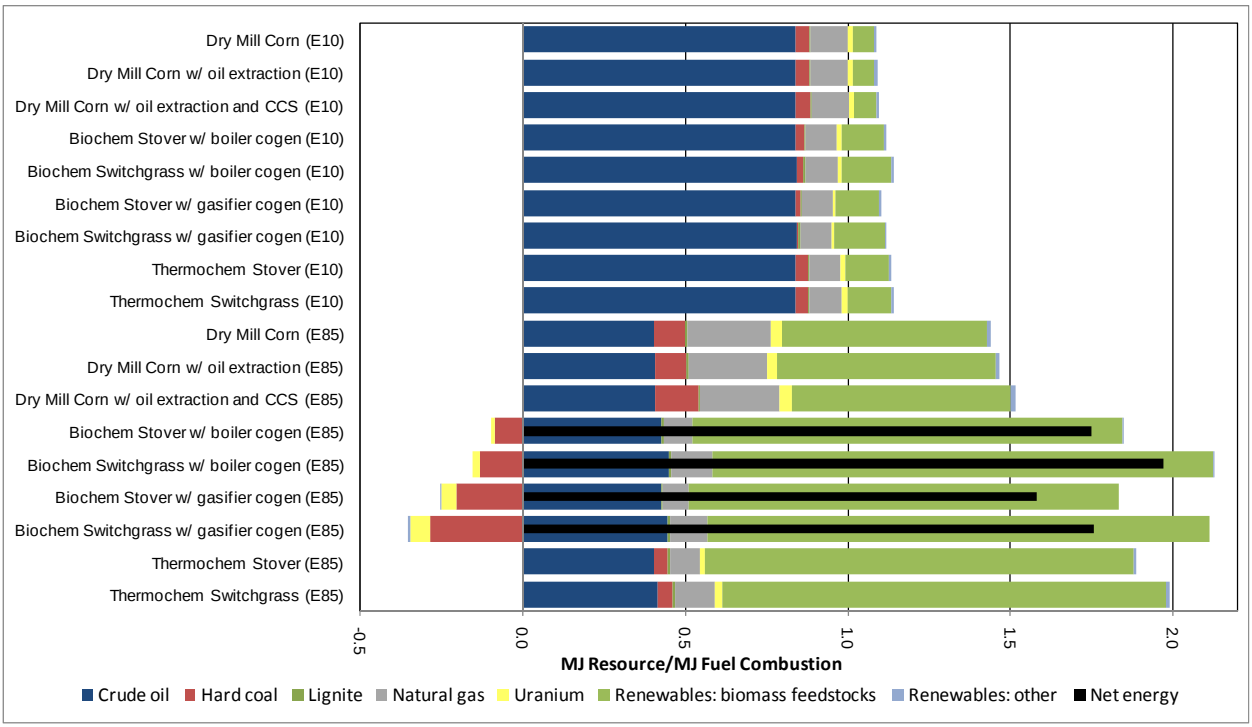

Figure F-1: Resource Energy Profile for E10 and E85 Pathways

Table F-3: Resource Energy in MJ per 1 MJ of E10 or E85 Fuel

	Crude Oil	Hard Coal	Lignite	Natural Gas	Uranium	Renewable (biomass)	Renewable (other)	Total
Dry Grind Corn (E10)	8.38E-01	4.44E-02	4.27E-03	1.13E-01	1.67E-02	6.30E-02	8.62E-03	1.09
Dry Grind Corn w/ oil extraction (E10)	8.38E-01	4.45E-02	4.28E-03	1.11E-01	1.66E-02	6.71E-02	8.64E-03	1.09
Dry Grind Corn w/ oil extraction and CCS (E10)	8.38E-01	4.81E-02	4.30E-03	1.11E-01	1.75E-02	6.71E-02	8.82E-03	1.10
Biochem Stover w/ FBC cogen (E10)	8.41E-01	2.65E-02	4.26E-03	9.60E-02	1.22E-02	1.32E-01	7.73E-03	1.12
Biochem Switchgrass w/ FBC cogen (E10)	8.43E-01	2.16E-02	4.46E-03	9.97E-02	1.13E-02	1.54E-01	7.52E-03	1.14
Biochem Stover w/ gasifier cogen (E10)	8.40E-01	1.44E-02	4.21E-03	9.52E-02	9.15E-03	1.32E-01	7.14E-03	1.10
Biochem Switchgrass w/ gasifier cogen (E10)	8.42E-01	6.43E-03	4.39E-03	9.87E-02	7.42E-03	1.54E-01	6.78E-03	1.12
Thermochem Stover (E10)	8.38E-01	3.93E-02	4.27E-03	9.64E-02	1.53E-02	1.31E-01	8.32E-03	1.13
Thermochem Switchgrass (E10)	8.39E-01	3.95E-02	4.44E-03	9.94E-02	1.55E-02	1.36E-01	8.35E-03	1.14
Dry Grind Corn (E85)	4.05E-01	9.60E-02	5.97E-03	2.58E-01	3.21E-02	6.32E-01	1.15E-02	1.44
Dry Grind Corn w/ oil extraction (E85)	4.07E-01	9.69E-02	6.12E-03	2.41E-01	3.03E-02	6.72E-01	1.17E-02	1.46
Dry Grind Corn w/ oil extraction and CCS (E85)	4.07E-01	1.34E-01	6.26E-03	2.43E-01	3.96E-02	6.72E-01	1.35E-02	1.51
Biochem Stover w/ FBC cogen (E85)	4.28E-01	-8.35E-02	5.89E-03	8.75E-02	-1.34E-02	1.32E+00	2.52E-03	1.75
Biochem Switchgrass w/ FBC cogen (E85)	4.50E-01	-1.33E-01	7.87E-03	1.24E-01	-2.29E-02	1.54E+00	4.37E-04	1.97
Biochem Stover w/ gasifier cogen (E85)	4.25E-01	-2.04E-01	5.34E-03	7.97E-02	-4.40E-02	1.32E+00	-3.35E-03	1.58
Biochem Switchgrass w/ gasifier cogen (E85)	4.45E-01	-2.84E-01	7.17E-03	1.14E-01	-6.14E-02	1.54E+00	-6.94E-03	1.76
Thermochem Stover (E85)	4.02E-01	4.46E-02	6.02E-03	9.17E-02	1.73E-02	1.32E+00	8.46E-03	1.89
Thermochem Switchgrass (E85)	4.16E-01	4.69E-02	7.66E-03	1.22E-01	2.01E-02	1.37E+00	8.79E-03	1.99

Table F-4: Net Water Withdrawal in m^3 per 1 MJ of E10 or E85 Fuel

	LC Stage #1	LC Stage #2	LC Stage #3	LC Stage #4	LC Stage #5	Total
Dry Grind Corn (E10)	8.19	9.40E-04	5.44E-02	1.09E-03	1.42E-02	8.26
Dry Grind Corn w/ oil extraction (E10)	8.19	9.42E-04	4.23E-02	1.09E-03	1.42E-02	8.25
Dry Grind Corn w/ oil extraction and CCS (E10)	8.19	9.42E-04	4.29E-02	1.09E-03	1.42E-02	8.25
Biochem Stover w/ boiler cogen (E10)	4.34	9.74E-04	7.37E-02	1.09E-03	1.42E-02	4.43
Biochem Switchgrass w/ boiler cogen (E10)	17.3	9.87E-04	8.09E-02	1.09E-03	1.42E-02	17.4
Biochem Stover w/ gasifier cogen (E10)	4.34	9.74E-04	8.14E-02	1.09E-03	1.42E-02	4.44
Biochem Switchgrass w/ gasifier cogen (E10)	17.3	9.87E-04	8.69E-02	1.09E-03	1.42E-02	17.4
Thermochem Stover (E10)	4.97	9.74E-04	5.29E-02	1.09E-03	1.42E-02	5.04
Thermochem Switchgrass (E10)	17.7	9.78E-04	5.29E-02	1.09E-03	1.42E-02	17.7
Dry Grind Corn (E85)	61.5	6.21E-04	6.42E-02	1.59E-03	1.42E-02	61.5
Dry Grind Corn w/ oil extraction (E85)	61.5	6.40E-04	-5.70E-02	1.59E-03	1.42E-02	61.4
Dry Grind Corn w/ oil extraction and CCS (E85)	61.5	6.40E-04	-5.10E-02	1.59E-03	1.42E-02	61.4
Biochem Stover w/ boiler cogen (E85)	32.6	9.63E-04	2.57E-01	1.59E-03	1.42E-02	32.9
Biochem Switchgrass w/ boiler cogen (E85)	130	1.09E-03	3.30E-01	1.59E-03	1.42E-02	130
Biochem Stover w/ gasifier cogen (E85)	32.6	9.63E-04	3.34E-01	1.59E-03	1.42E-02	32.9
Biochem Switchgrass w/ gasifier cogen (E85)	130	1.10E-03	3.89E-01	1.59E-03	1.42E-02	130
Thermochem Stover (E85)	37.3	-4.37E-01	-3.39E-01	2.14E-03	2.76E-02	36.6
Thermochem Switchgrass (E85)	132	1.01E-03	4.92E-02	1.59E-03	1.42E-02	133

The results for CAP emissions are shown in **Figure F-2** through **Figure F-4** and **Table F-5** through **Table F-8**. These CAP emissions include SO_2 (sulfur dioxide), NO_x (nitrogen oxides), CO (carbon monoxide), and Pb (lead). These figures show CAP emissions for each of the 18 pathways and each of the five LC stages.

In some cases, negative emissions result from co-products that displace products from non-ethanol supply chains. The dry grind and biochemical pathways have co-products that result in the displacement of emissions. The thermochemical pathways do not have any co-products that result in the displacement of emissions. For the biochemical ethanol pathways, which include the export of electricity to the MROW electricity grid, the magnitude of displacement is large enough to result in negative emissions of SO_2, NO_x, and Pb from LC Stage #3. The following figures represent negative emissions by showing a bar to the left of the vertical axis. To indicate the net emissions of the entire life cycle of pathways with negative emissions, a narrow black bar is shown within the associated data series.

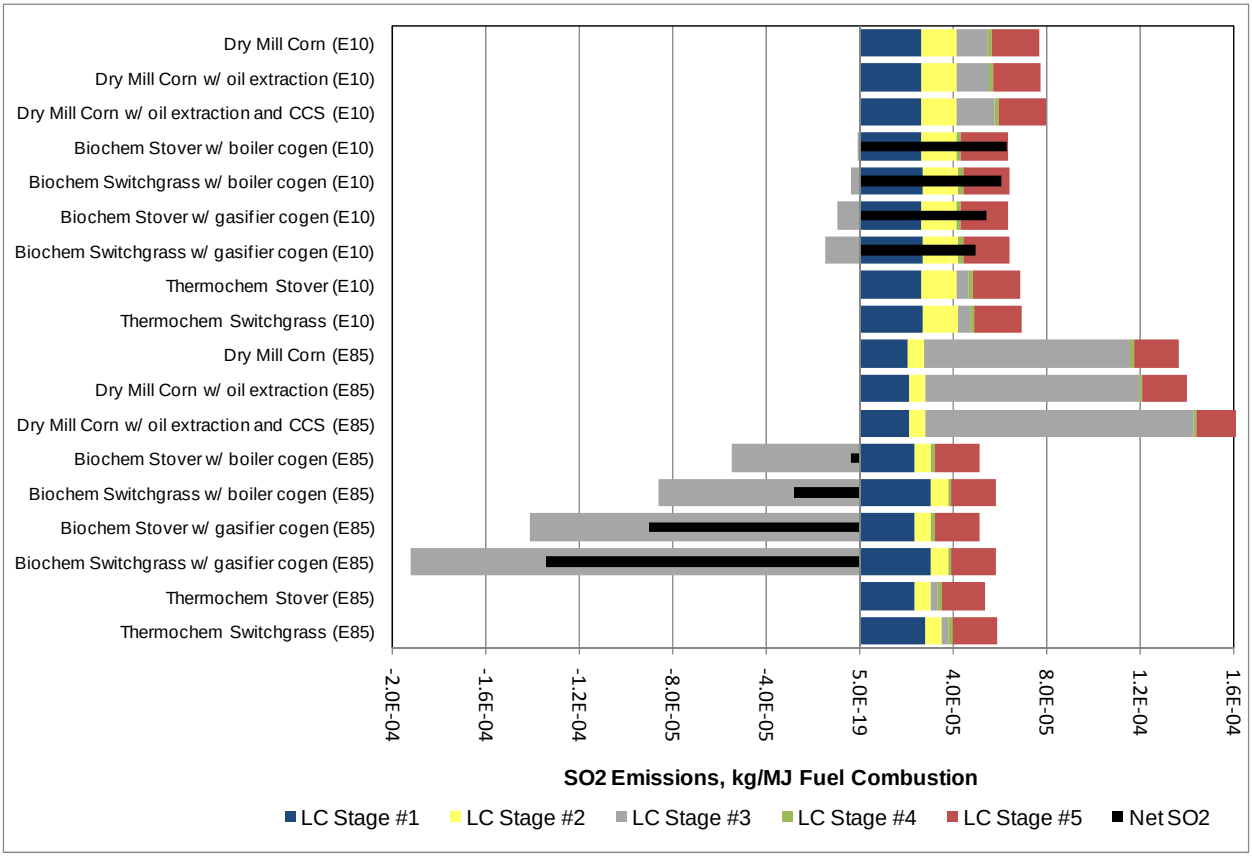

Figure F-2: SO_2 Emissions from E10 and E85 Pathways (Cradle-to-Combustion)

As demonstrated by the diversity of LC stages shown in **Figure F-2**, SO_2 emissions originate from many activities of the E10 and E85 pathways. SO_2 is an emission associated with the production of gasoline, the production and combustion of diesel used in farm equipment and biomass trucks, the production of fertilizers, and the generation of electricity. These activities are a part of every pathway of this study, yet occur in varying proportions. All pathways use gasoline, but E10 fuel has a higher volume of gasoline than E85 fuel. All pathways include the combustion of diesel in farm equipment and biomass trucks, but the proportion of diesel combustion in farm equipment and biomass trucks increases with an increasing use of biomass. All pathways use fertilizer, but corn stover pathways use significantly more fertilizer than other pathways due to the nutrient replacement required after the collection of stover. Finally, all pathways use electricity, but the biochemical ethanol pathways co-generate electricity from residual biomass and, in turn, displace MROW grid electricity. The overall balance of SO_2 emissions demonstrates that the dry grind pathways to E85 production have the highest SO_2 emissions, while biochemical pathways have negative net SO_2 emissions (due to the export of electricity).

Table F-5: SO_2 Emissions in kg per 1 MJ of E10 or E85 Fuel

	LC Stage #1	LC Stage #2	LC Stage #3	LC Stage #4	LC Stage #5	Total
Dry Grind Corn (E10)	2.71E-05	1.51E-05	5.05E-06	1.89E-06	2.01E-05	6.92E-05
Dry Grind Corn w/ oil extraction (E10)	2.66E-05	1.50E-05	5.05E-06	1.89E-06	2.01E-05	6.87E-05
Dry Grind Corn w/ oil extraction and CCS (E10)	2.73E-05	1.51E-05	-1.44E-05	1.89E-06	2.01E-05	5.00E-05
Biochem Stover w/ boiler cogen (E10)	2.66E-05	1.51E-05	-9.33E-06	1.89E-06	2.01E-05	5.44E-05
Biochem Switchgrass w/ boiler cogen (E10)	2.73E-05	1.51E-05	-3.86E-06	1.89E-06	2.01E-05	6.05E-05
Biochem Stover w/ gasifier cogen (E10)	2.66E-05	1.51E-05	-7.06E-07	1.89E-06	2.01E-05	6.30E-05
Biochem Switchgrass w/ gasifier cogen (E10)	2.64E-05	1.50E-05	1.62E-05	1.89E-06	2.01E-05	7.96E-05
Thermochem Stover (E10)	2.64E-05	1.50E-05	1.39E-05	1.89E-06	2.01E-05	7.73E-05
Thermochem Switchgrass (E10)	2.63E-05	1.50E-05	1.36E-05	1.89E-06	2.01E-05	7.69E-05
Dry Grind Corn (E85)	2.81E-05	7.24E-06	3.03E-06	1.51E-06	1.90E-05	5.88E-05
Dry Grind Corn w/ oil extraction (E85)	2.34E-05	7.08E-06	3.03E-06	1.51E-06	1.90E-05	5.40E-05
Dry Grind Corn w/ oil extraction and CCS (E85)	3.04E-05	7.44E-06	-1.92E-04	1.51E-06	1.90E-05	-1.34E-04
Biochem Stover w/ boiler cogen (E85)	2.36E-05	7.19E-06	-1.41E-04	1.51E-06	1.90E-05	-8.98E-05
Biochem Switchgrass w/ boiler cogen (E85)	3.04E-05	7.44E-06	-8.63E-05	1.51E-06	1.90E-05	-2.79E-05
Biochem Stover w/ gasifier cogen (E85)	2.36E-05	7.19E-06	-5.47E-05	1.51E-06	1.90E-05	-3.39E-06
Biochem Switchgrass w/ gasifier cogen (E85)	2.10E-05	7.04E-06	1.15E-04	1.51E-06	1.90E-05	1.63E-04
Thermochem Stover (E85)	2.12E-05	7.04E-06	9.14E-05	1.51E-06	1.90E-05	1.40E-04
Thermochem Switchgrass (E85)	2.04E-05	7.03E-06	8.85E-05	1.51E-06	1.90E-05	1.36E-04

As shown in

Table F-6 and **Table F-7**, the majority of NO_x and CO emissions occur during LC Stage #5 (vehicle use). At least 60 percent of NO_x emissions and nearly 100 percent of CO emissions occur during vehicle use (LC Stage #5). Thus, the characteristics of E10 and E85 combustion influence the overall LC results for NO_x and CO emissions. The combustion of E10 and E85 demonstrate a tradeoff between NO_x (nitrogen oxides) and CO (carbon monoxide) emissions. The majority of NO_x and CO emissions occur in the final life cycle stage – the combustion of fuel in a passenger vehicle. The E10 pathways have higher NO_x emissions than the E85 pathways because when E10 is combusted it has a higher NO_x emission factor than E85. Conversely, the E85 pathways have higher CO emissions than the E10 pathways, because when E85 is combusted it has a higher CO emission factor than E10.

Additionally, the biochemical pathways displace NO_x emissions because of the sale of electricity to the MROW grid. The combination of the low NO_x emissions from E85 combustion and the

displaced electricity from the thermochemical ethanol plants gives the thermochemical pathways for E85 production the lowest NO_x profiles of all pathways of this analysis.

Table F-6: NO_x Emissions in kg per 1 MJ of E10 or E85 Fuel

	LC Stage #1	LC Stage #2	LC Stage #3	LC Stage #4	LC Stage #5	Total
Dry Grind Corn (E10)	1.49E-05	2.04E-05	7.19E-06	2.17E-06	2.03E-04	2.48E-04
Dry Grind Corn w/ oil extraction (E10)	1.50E-05	2.04E-05	6.17E-06	2.17E-06	2.03E-04	2.47E-04
Dry Grind Corn w/ oil extraction and CCS (E10)	1.50E-05	2.04E-05	5.47E-06	2.17E-06	2.03E-04	2.46E-04
Biochem Stover w/ boiler cogen (E10)	1.68E-05	2.04E-05	2.05E-06	2.17E-06	2.03E-04	2.44E-04
Biochem Switchgrass w/ boiler cogen (E10)	1.55E-05	2.04E-05	2.05E-06	2.17E-06	2.03E-04	2.43E-04
Biochem Stover w/ gasifier cogen (E10)	1.72E-05	2.04E-05	-9.31E-07	2.17E-06	2.03E-04	2.42E-04
Biochem Switchgrass w/ gasifier cogen (E10)	1.55E-05	2.04E-05	8.93E-08	2.17E-06	2.03E-04	2.41E-04
Thermochem Stover (E10)	1.72E-05	2.04E-05	-4.35E-06	2.17E-06	2.03E-04	2.39E-04
Thermochem Switchgrass (E10)	1.55E-05	2.04E-05	-2.73E-06	2.17E-06	2.03E-04	2.38E-04
Dry Grind Corn (E85)	2.00E-05	9.36E-06	5.31E-05	1.39E-06	1.25E-04	2.09E-04
Dry Grind Corn w/ oil extraction (E85)	2.09E-05	9.37E-06	4.28E-05	1.39E-06	1.25E-04	2.00E-04
Dry Grind Corn w/ oil extraction and CCS (E85)	2.11E-05	9.37E-06	3.59E-05	1.39E-06	1.25E-04	1.93E-04
Biochem Stover w/ boiler cogen (E85)	3.89E-05	9.40E-06	1.51E-06	1.39E-06	1.25E-04	1.77E-04
Biochem Switchgrass w/ boiler cogen (E85)	2.58E-05	9.28E-06	1.51E-06	1.39E-06	1.25E-04	1.63E-04
Biochem Stover w/ gasifier cogen (E85)	4.32E-05	9.61E-06	-2.83E-05	1.39E-06	1.25E-04	1.51E-04
Biochem Switchgrass w/ gasifier cogen (E85)	2.60E-05	9.41E-06	-1.81E-05	1.39E-06	1.25E-04	1.44E-04
Thermochem Stover (E85)	4.32E-05	9.61E-06	-6.26E-05	1.39E-06	1.25E-04	1.17E-04
Thermochem Switchgrass (E85)	2.60E-05	9.41E-06	-4.63E-05	1.39E-06	1.25E-04	1.16E-04

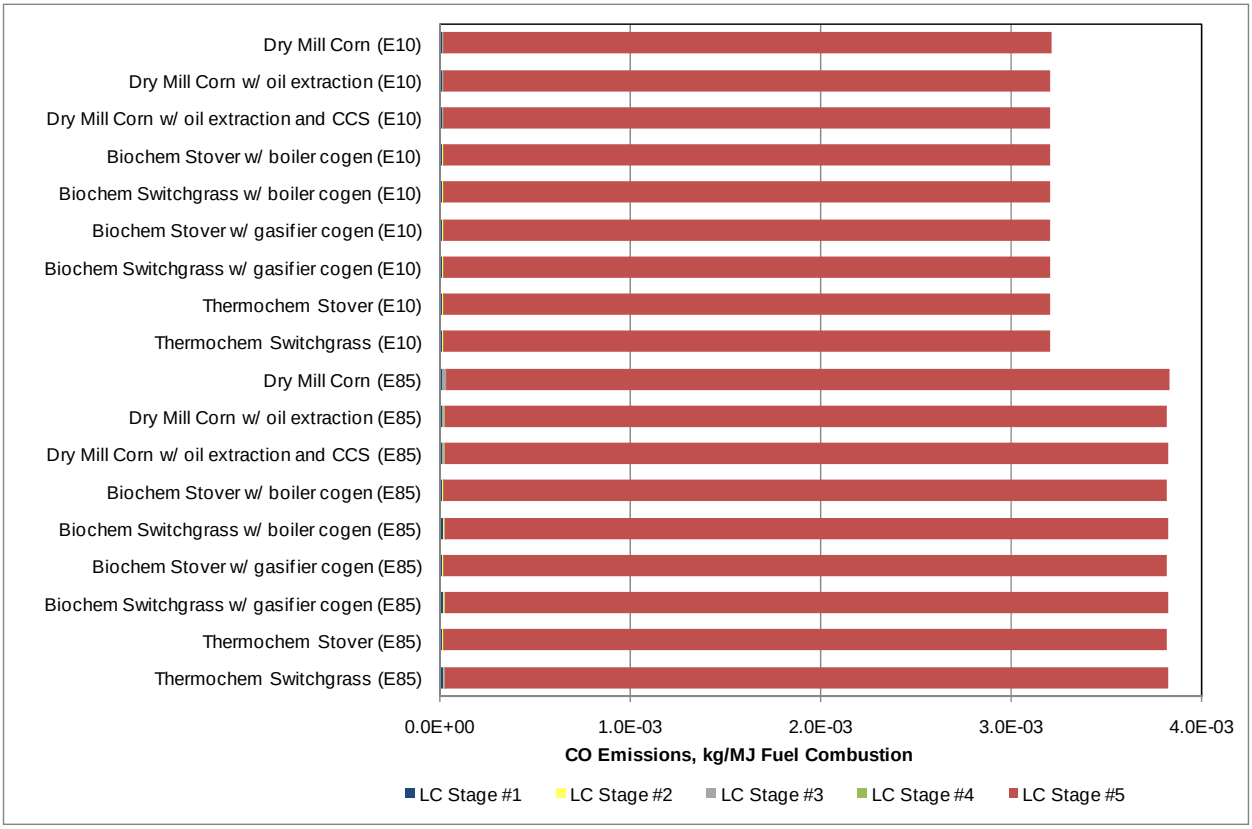

Figure F-3: CO Emissions from E10 and E85 Pathways (Cradle-to-Combustion)

Table F-7: CO Emissions in kg per 1 MJ of E10 or E85 Fuel

	LC Stage #1	LC Stage #2	LC Stage #3	LC Stage #4	LC Stage #5	Total
Dry Grind Corn (E10)	9.32E-06	3.92E-06	2.38E-06	1.22E-06	3.19E-03	3.21E-03
Dry Grind Corn w/ oil extraction (E10)	9.36E-06	3.92E-06	1.33E-06	1.22E-06	3.19E-03	3.21E-03
Dry Grind Corn w/ oil extraction and CCS (E10)	9.35E-06	3.92E-06	1.40E-06	1.22E-06	3.19E-03	3.21E-03
Biochem Stover w/ boiler cogen (E10)	9.66E-06	3.97E-06	9.17E-07	1.22E-06	3.19E-03	3.21E-03
Biochem Switchgrass w/ boiler cogen (E10)	1.02E-05	4.00E-06	7.07E-07	1.22E-06	3.19E-03	3.21E-03
Biochem Stover w/ gasifier cogen (E10)	9.66E-06	3.97E-06	-3.63E-08	1.22E-06	3.19E-03	3.21E-03
Biochem Switchgrass w/ gasifier cogen (E10)	1.02E-05	4.00E-06	-3.74E-07	1.22E-06	3.19E-03	3.21E-03
Thermochem Stover (E10)	9.65E-06	3.96E-06	9.35E-07	1.22E-06	3.19E-03	3.21E-03
Thermochem Switchgrass (E10)	1.01E-05	3.99E-06	9.35E-07	1.22E-06	3.19E-03	3.21E-03
Dry Grind Corn (E85)	1.00E-05	2.11E-06	1.75E-05	1.54E-06	3.80E-03	3.83E-03
Dry Grind Corn w/ oil extraction (E85)	1.05E-05	2.14E-06	7.05E-06	1.54E-06	3.80E-03	3.82E-03
Dry Grind Corn w/ oil extraction and CCS (E85)	1.04E-05	2.14E-06	7.74E-06	1.54E-06	3.80E-03	3.82E-03
Biochem Stover w/ boiler cogen (E85)	1.35E-05	2.58E-06	2.91E-06	1.54E-06	3.80E-03	3.82E-03
Biochem Switchgrass w/ boiler cogen (E85)	1.92E-05	2.93E-06	7.97E-07	1.54E-06	3.80E-03	3.82E-03
Biochem Stover w/ gasifier cogen (E85)	1.35E-05	2.58E-06	-6.65E-06	1.54E-06	3.80E-03	3.81E-03
Biochem Switchgrass w/ gasifier cogen (E85)	1.92E-05	2.93E-06	-1.00E-05	1.54E-06	3.80E-03	3.81E-03
Thermochem Stover (E85)	1.34E-05	2.55E-06	3.09E-06	1.54E-06	3.80E-03	3.82E-03
Thermochem Switchgrass (E85)	1.74E-05	2.77E-06	3.09E-06	1.54E-06	3.80E-03	3.82E-03

As shown in **Figure F-4** and **Table F-8**, the E85 pathways have higher lead emissions than the E10 pathways. The Pb emissions of the E10 pathways are 5 to 20 percent lower than the corresponding E85 pathways. The higher Pb emissions of the E85 pathways are due to diesel combustion during the production of biomass feedstocks in LC Stage #1. However, the biochemical technology that employs a gasifier for electricity cogeneration for E85 production displaces enough Pb emissions (as shown by the bars to the left of the vertical axis in **Figure F-4**) to result in net Pb emissions that are comparable to the E10 pathways.

Since the pathways of this analysis do not include significant inputs of coal, mercury emissions are relatively low for all pathways of this analysis.

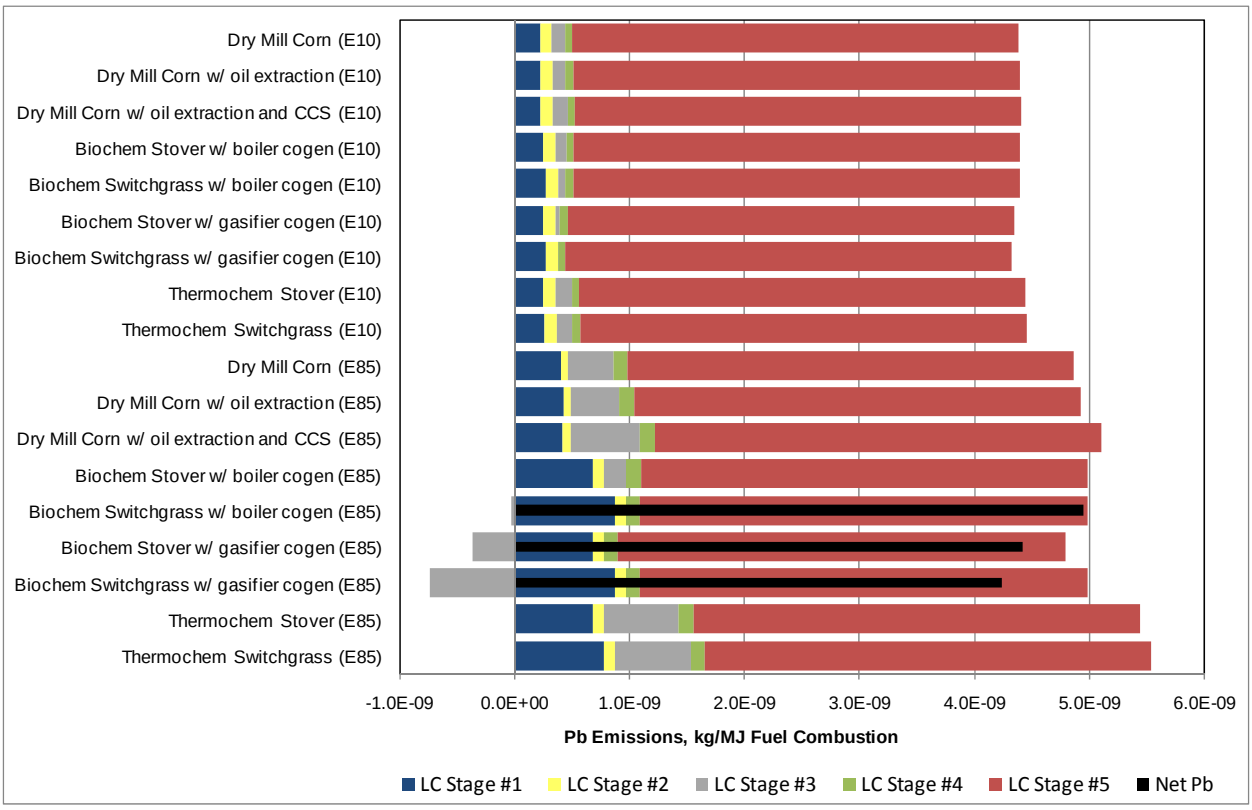

Figure F-4: Pb Emissions from E10 and E85 Pathways (Cradle-to-Combustion)

Table F-8: Pb Emissions in kg per 1 MJ of E10 or E85 Fuel

	LC Stage #1	LC Stage #2	LC Stage #3	LC Stage #4	LC Stage #5	Total
Dry Grind Corn (E10)	2.26E-10	9.97E-11	1.13E-10	6.71E-11	3.88E-09	4.39E-09
Dry Grind Corn w/ oil extraction (E10)	2.28E-10	9.98E-11	1.16E-10	6.71E-11	3.88E-09	4.39E-09
Dry Grind Corn w/ oil extraction and CCS (E10)	2.28E-10	9.98E-11	1.34E-10	6.71E-11	3.88E-09	4.41E-09
Biochem Stover w/ boiler cogen (E10)	2.54E-10	1.02E-10	9.36E-11	6.71E-11	3.88E-09	4.40E-09
Biochem Switchgrass w/ boiler cogen (E10)	2.72E-10	1.03E-10	7.09E-11	6.71E-11	3.88E-09	4.40E-09
Biochem Stover w/ gasifier cogen (E10)	2.54E-10	1.02E-10	3.79E-11	6.71E-11	3.88E-09	4.34E-09
Biochem Switchgrass w/ gasifier cogen (E10)	2.72E-10	1.03E-10	8.42E-13	6.71E-11	3.88E-09	4.33E-09
Thermochem Stover (E10)	2.53E-10	1.02E-10	1.40E-10	6.71E-11	3.88E-09	4.45E-09
Thermochem Switchgrass (E10)	2.63E-10	1.03E-10	1.40E-10	6.71E-11	3.88E-09	4.46E-09
Dry Grind Corn (E85)	4.03E-10	6.59E-11	3.88E-10	1.25E-10	3.88E-09	4.86E-09
Dry Grind Corn w/ oil extraction (E85)	4.25E-10	6.73E-11	4.22E-10	1.25E-10	3.88E-09	4.92E-09
Dry Grind Corn w/ oil extraction and CCS (E85)	4.23E-10	6.73E-11	6.03E-10	1.25E-10	3.88E-09	5.10E-09
Biochem Stover w/ boiler cogen (E85)	6.85E-10	9.36E-11	1.94E-10	1.25E-10	3.88E-09	4.98E-09
Biochem Switchgrass w/ boiler cogen (E85)	8.68E-10	1.02E-10	-3.35E-11	1.25E-10	3.88E-09	4.94E-09
Biochem Stover w/ gasifier cogen (E85)	6.85E-10	9.36E-11	-3.65E-10	1.25E-10	3.88E-09	4.42E-09
Biochem Switchgrass w/ gasifier cogen (E85)	8.68E-10	1.02E-10	-7.36E-10	1.25E-10	3.88E-09	4.24E-09
Thermochem Stover (E85)	6.81E-10	9.27E-11	6.58E-10	1.25E-10	3.88E-09	5.44E-09
Thermochem Switchgrass (E85)	7.77E-10	9.48E-11	6.58E-10	1.25E-10	3.88E-09	5.54E-09

Table F-9 shows the land transformed for each pathway. Ethanol pathways that utilize corn stover or corn grain as the sole feedstock result in no land transformation for LC Stage 1. Land transformed for LC Stages 3 and 4 for all pathways are relatively consistent, based on the size of the ethanol facility, as well as whether or not CCS is used. Also, because results are normalized per MJ of fuel, land use rates vary based on the fraction of ethanol in the blended fuel (E10 or E85).

Table F-9: Land Transformed, Per Reference Flow for Each LC Stage (m^2/MJ)

Pathway	LC Stage 1	LC Stage 3	LC Stage 4
Dry Grind Corn (E10)	0	0	0
Dry Grind Corn w/ oil extraction (E10)	0	0	0
Dry Grind Corn w/ oil extraction and CCS (E10)	0	1.43E-07	1.09E-06
Biochem Stover w/ boiler cogen (E10)	0	1.37E-06	1.05E-05
Biochem Switchgrass w/ boiler cogen (E10)	0	1.23E-06	1.09E-06
Biochem Stover w/ gasifier cogen (E10)	0	1.18E-05	1.05E-05
Biochem Switchgrass w/ gasifier cogen (E10)	0	1.43E-07	9.52E-07
Thermochem Stover (E10)	0	1.37E-06	9.14E-06
Thermochem Switchgrass (E10)	4.72E-04	1.43E-07	9.52E-07
Dry Grind Corn (E85)	4.53E-03	1.37E-06	9.14E-06
Dry Grind Corn w/ oil extraction (E85)	0	1.43E-07	9.52E-07
Dry Grind Corn w/ oil extraction and CCS (E85)	0	1.37E-06	9.14E-06
Biochem Stover w/ boiler cogen (E85)	4.72E-04	1.43E-07	9.52E-07
Biochem Switchgrass w/ boiler cogen (E85)	4.53E-03	1.37E-06	9.14E-06
Biochem Stover w/ gasifier cogen (E85)	0	1.43E-07	1.09E-06
Biochem Switchgrass w/ gasifier cogen (E85)	0	1.37E-06	1.05E-05
Thermochem Stover (E85)	5.41E-04	1.43E-07	1.09E-06
Thermochem Switchgrass (E85)	5.19E-03	1.37E-06	1.05E-05

Table F-10: GHG Emissions due to Land Transformation, Per Reference Flow for Each LC Stage (kg CO_2e)

Pathway	LC Stage 1	LC Stage 3	LC Stage 4
Dry Grind Corn (E10)	0	0	0
Dry Grind Corn w/ oil extraction (E10)	0	0	0
Dry Grind Corn w/ oil extraction and CCS (E10)	0	7.96E-07	1.14E-07
Biochem Stover w/ boiler cogen (E10)	0	7.64E-06	1.10E-06
Biochem Switchgrass w/ boiler cogen (E10)	0	9.11E-07	1.14E-07
Biochem Stover w/ gasifier cogen (E10)	0	8.74E-06	1.10E-06
Biochem Switchgrass w/ gasifier cogen (E10)	0	7.96E-07	1.00E-07
Thermochem Stover (E10)	0	7.64E-06	9.60E-07
Thermochem Switchgrass (E10)	2.15E-03	7.96E-07	1.00E-07
Dry Grind Corn (E85)	2.06E-02	7.64E-06	9.60E-07
Dry Grind Corn w/ oil extraction (E85)	0	7.96E-07	1.00E-07
Dry Grind Corn w/ oil extraction and CCS (E85)	0	7.64E-06	9.60E-07
Biochem Stover w/ boiler cogen (E85)	2.15E-03	7.96E-07	1.00E-07
Biochem Switchgrass w/ boiler cogen (E85)	2.06E-02	7.64E-06	9.60E-07
Biochem Stover w/ gasifier cogen (E85)	0	7.96E-07	1.15E-07
Biochem Switchgrass w/ gasifier cogen (E85)	0	7.64E-06	1.10E-06
Thermochem Stover (E85)	2.46E-03	7.96E-07	1.15E-07
Thermochem Switchgrass (E85)	2.36E-02	7.64E-06	1.10E-06

APPENDIX G: TRANSFORMED LAND AREA

There were four relevant land use types identified within the footprints of the various facilities. These are grassland, forest, agriculture, and barren. Barren includes dirt or rocky soils that have been denuded of vegetation, as well as paved surfaces.

Among switchgrass, corn stover, and corn grain, it was assumed that only switchgrass results in land use change from non-agriculture to agriculture (the other sources of biomass utilize existing agricultural lands). **Figure G-1** shows two characteristic parcels for switchgrass production in the Midwest. As shown, barren areas account for 59% of the total area, forest for 29%, and grassland for 12%. No agricultural lands were considered for switchgrass production.

The assumed geographical region for the ethanol plants of this analysis is the U.S. Midwest. Specifically, in order to assess the land use effects of ethanol plants, this analysis uses the land characteristics of Iowa. Iowa has one existing land use category: agriculture (100%), as shown in **Figure G-2**. Due to the proximity of the ethanol plant site to the CCS pipeline and ethanol transport pipeline, agriculture is assumed to be the original state land use for these facilities as well. No land use change is calculated for LC Stage 3 of the basic dry grind ethanol pathways (those that do not use corn oil extraction or CCS). Otherwise, the advanced dry grind plants (those with corn oil extraction or CCS), the biochemical ethanol plants, and the thermochemical ethanol plants are modeled as newly constructed facilities that do cause a land use change in LC Stage #3.

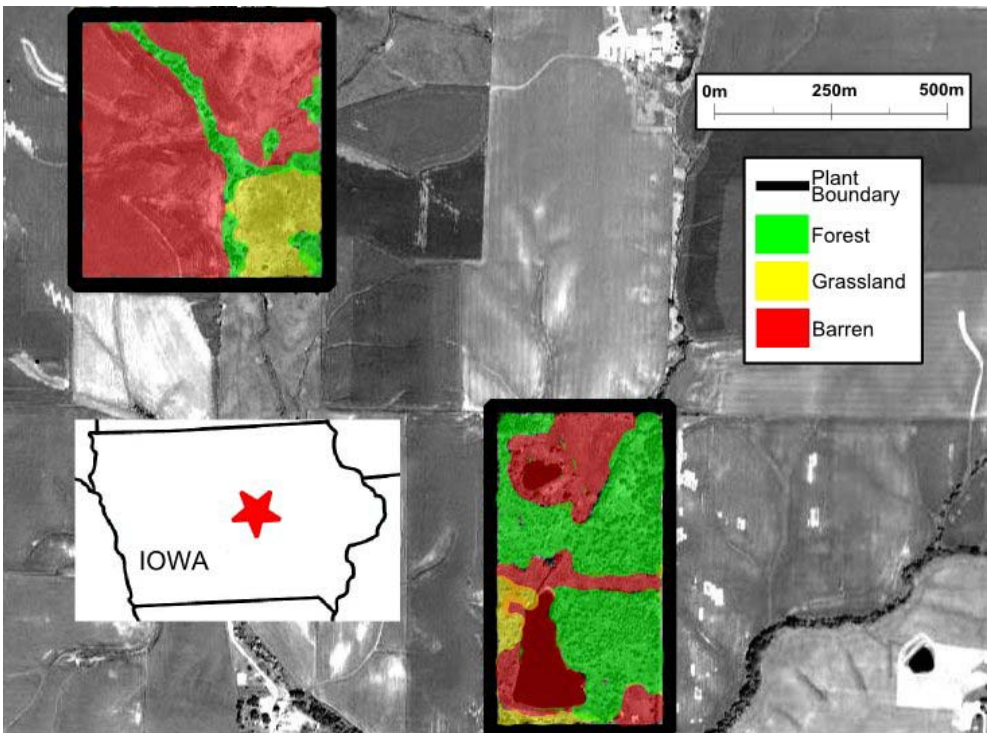

Figure G-1: Existing Condition Land Use Assessment: Switchgrass Production

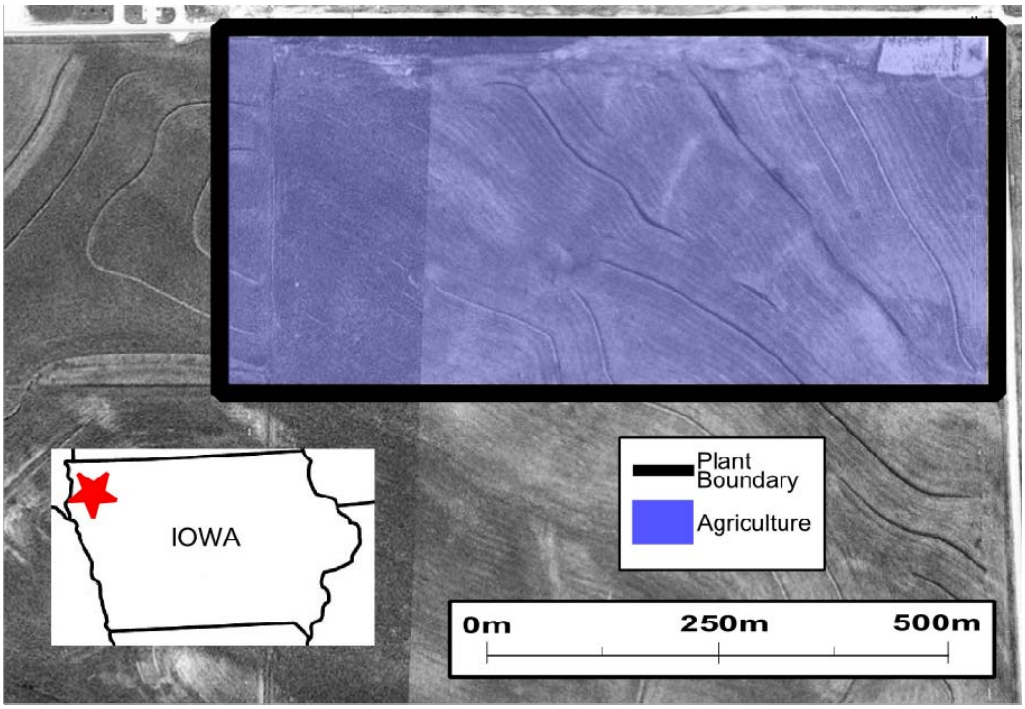

Figure G-2: Existing Condition Land Use Assessment for New Ethanol Plant Construction