Figure 1S shows the life cycle GHG emissions for major life cycle stages by scenario (lignin-land amendment, electricity generation through coal substitution and onsite power generation) and by location for ethanol production. Onsite power generation is identical to the techno-economic model of Humbird et al. (1), and the land amendment and coal cofiring scenarios are modifications of this design described in more detail in this SI. Included in the figure is the biogenic carbon from feedstock production and the net GHG emissions. Table 1S summarizes GHG emissions and data sources.
Table 1S. GHG emissions sources and sinks of life cycle components: Feedstock production, Feedstock Transport, and Fuel Conversion for the studied scenarios and locations. All units in g CO2e per MJ ethanol.1

| Life Cycle Components | Model or Data Source | Boone County, IA | Queen Anne County, MD | Lenoir County, NC |
|-----------------------|----------------------|------------------|----------------------|------------------|
|                       |                      | Land Amendment   | Coal Subs. | Power | Land Amendment | Coal Subs. | Power | Land Amendment | Coal Subs. | Power |
| Harvest               | Spatari et al. 2010, SimaPro 7.3.2 (2) | 12.8 | 12.8 | 12.8 | 12.8 | 12.8 | 12.8 | 12.8 | 12.8 | 12.8 |
| Nitrogen replacement2 | Spatari et al. 2010, SimaPro 7.3.2 (2) | 0 | 5 | 5 | 0 | 5 | 5 | 0 | 5 | 5 |
| Total soil N2O emission | DayCent, Adler et al.(3) | 3.4 | 6.9 | 6.9 | 2.5 | 3.8 | 3.8 | 2.2 | 3.3 | 3.3 |
| Change in soil carbon | DayCent, Adler et al.(3) | 0.48 | 25.2 | 25.2 | -1.05 | 22.1 | 22.1 | -4.7 | 17.2 | 17.2 |
| Biogenic carbon3 | Aspen Model feedstock input | -233.6 | -233.6 | -233.6 | -233.6 | -233.6 | -233.6 | -233.6 | -233.6 | -233.6 |
| Feedstock Transport | SimaPro 7.3.2 (2) | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 | 2 |
| Protein               | MacLean and Spatari (5) SimaPro 7.3.2 (2) | 5.9 | 5.9 | 5.9 | 5.9 | 5.9 | 5.9 | 5.9 | 5.9 | 5.9 |
| Pretreatment chemicals, Nutrients, Enzymes | Spatari et al. 4 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 | 45 |
| Fermentative CO24 | Aspen Simulation | 40 | 40 | 122 | 40 | 40 | 122 | 40 | 40 | 122 |
| Boiler5 | Aspen Simulation | 1 | 0.6 | N/A6 | 1 | 0.6 | N/A | 1 | 0.6 | N/A |
| Transportation of HLFB | SimaPro 7.3.2 (2) | 49.7 | 49.7 | N/A | 35.7 | 35.7 | N/A | 33.5 | 33.5 | N/A |
| Electricity6 | SimaPro 7.3.2 (2), Jaramillo, Griffin (6), Kim and Dale (7), GREET (8), (9) | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Process | GREET (8) | 71 | 71 | N/A | 71 | 71 | N/A | 71 | 71 | N/A |
| Coproduct | N/A | 8210 | N/A | 82 | N/A | 82 | N/A | 82 | N/A | N/A |
| HLFB combustion | N/A | 8211 | N/A | 82 | N/A | 82 | N/A | 82 | N/A | N/A |
| Fuel transport & distribution | GREET (8) | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 | 1 |
| Ethanol Combustion | Stoichiometry | 40.5 | 40.5 | 40.5 | 40.5 | 40.5 | 40.5 | 40.5 | 40.5 | 40.5 |

1Emissions are calculated assuming the 100 year global warming potential from (10), for methane (25 g CO2e); nitrous oxide (298 g CO2e); and carbon dioxide (1 g CO2e) for each functional unit (MJ) of ethanol. Density and lower heating value (LHV) of ethanol used in calculations are 0.789 kg/l and 21.3 MJ/L, respectively.

2We assume that application of the high lignin fermentation byproduct (HLFB) will offset the need to use fertilizers to replace nutrients, thus GHG emissions from the land amendment “feedstock” scenario include the emission from harvesting the feedstock only.

3Carbon entering the biorefinery as part of the feedstock.
Fermentative CO₂ is the release of part of the biogenic carbon in the feedstock, and is emitted from the scrubber unit operation, fermentation and wastewater treatment sections of the biorefinery. Since ethanol yield is constant for all scenarios and feedstocks, fermentative CO₂ is also identical for all scenarios.

Boiler CO₂ emissions for all scenarios are from different portions of the feedstock (biogenic carbon). The boiler feed for onsite power production includes the lignin-byproduct sludge from anaerobic digestion and process biogas and for the land amendment and substitution options the boiler input is comprised only of biogas.

Boiler emissions in the land amendment and coal substitute scenarios include combusting the anaerobic digestion biogas to provide steam requirements for the biorefinery while boiler emissions for onsite power production include emissions from combusting the anaerobic digestion biogas and HLFB to provide steam and electricity for the biorefinery.

Electricity emissions, according to NERC reliability regions (11) are calculated based on the average grid mix for regions of MRO, RFC and SERC within which Iowa, Maryland and North Carolina are located, respectively. All fuel mixes were sourced from eGRID data (12). The average grid mix for MRO region is comprised of 69% coal, 2.7% NG, 0.4% petroleum, 14% nuclear and 13.9% others. The average electricity fuel mix for RFC region has 60% coal, 7.9% NG, 0.5% petroleum, 28% nuclear and 3.6%, and the average electricity mix for the SERC region is 50% coal, 17% NG, 0.7% petroleum, 26% nuclear and 6.3% others. The average 2009 GHG emissions for the three regions are: MRO (1.05 kg CO₂e/kWh); RFC (0.75 kg CO₂e/kWh); and SERC (0.7 kg CO₂e/kWh).

This number shows the net emission from the electricity generation in the scenario of coal substitute which consists of g CO₂ e/MJ of Ethanol for the electricity used by ethanol plant, 82 g CO₂ e/MJ of Ethanol emission offset from avoided coal consumption to generate electricity (which includes the whole life cycle of the amount of coal being offset) and 82 g CO₂ e/MJ of ethanol from burning of the lignin byproduct in coal plant.

The negative emission indicates a credit for the avoided GHG emissions from the production of the electricity in the coal fired power plants when substituting HLFB for coal.

The negative emission indicates a credit for the avoided GHG emissions from the production of surplus electricity using a lignin fed boiler, which substitutes for electricity from the regional grid.

Emission resulting from the combustion of HLFB in a coal-fired power plant.
GHG emissions data for biomass conversion to ethanol were taken from the original Aspen simulation from NREL (http://www.nrel.gov/extranet/biorefinery/aspen_models/) for all scenarios. Table 1S shows the sources of the GHG emissions data for different life cycle stages. For the HLFB land amendment and coal substitute scenarios the supply of steam and electricity was modified from the original Aspen model and redesigned for a boiler using biogas as feed for producing the biorefinery’s steam requirement. For these two scenarios, the biorefinery electricity requirement is assumed to be purchased from regional utilities and is reflected in the operating cost. In addition, in the coal substitute scenario the HLFB is dried to 20% moisture and delivered to a coal power plant to be cofired with the coal.

**Sensitivity analysis**

Table 2S shows the sensitivity analysis parameters selected for the environmental uncertainty analysis. These parameters have been chosen due to their expected significance on the economic and environmental performance (life cycle GHG emission) of the biorefinery.

**Table 2S. Parameter Ranges for Life Cycle Uncertainty Analysis**

| Parameter                          | Unit                  | Reference | Minimum | Maximum |
|------------------------------------|-----------------------|-----------|---------|---------|
| Process yield                      | L of ethanol/ Mg CS   | 300       | 270     | 330     |
| Transportation distance            | Miles                 | 50        | 50      | 100     |
| Cofiring Scenario                 |                       |           |         |         |
| Coal life cycle emission          | gCO₂e/MJ              | 96        | 89      | 106     |
| Onsite Power production Scenario  |                       |           |         |         |
| Electricity Coproduct             | %                     | 100       | 0       | 100     |

\(^1\) Process yields fall within an expected range for corn stover and mixtures of corn stover, wheat straw, and barley straw based on data from Spatari et al. (4).

\(^2\) Biomass supply may be sourced from counties within a 50 to 100 mi radius of the biorefinery.

\(^3\) Based on Venkatesh et al. (13)

\(^4\) Onsite power that is sold to the grid may not perfectly substitute and displace electricity from the average composite fuel mix in each biorefinery region. Therefore, our sensitivity analysis tests the extreme cases of 0% to 100% substitution, corresponding to the most and least conservative cases.

The grid electricity fuel mix for each region supplying electricity to the selected sites were set to eGrid 2012 data for year 2009 and compared to year 2007 data to reflect the range of fuel mix in recent years in each region. Table 3S below shows the parameter ranges selected for fuel mix of the regions according to eGrid data for years 2007 and 2009. The uncertainty analysis used
uniform distributions of fuel mix between the minimum and maximum fuel range to estimate the composite range of fuel mix supply.

Table 4S shows the 20-year average (for the Base Case results in Table 1S) and minimum and maximum soil N$_2$O emissions and changes to SOC for each county and scenario. These parameter settings were used in the single-variable sensitivity analysis and uncertainty analysis (set to triangular distributions).
Table 3S. Parameter ranges for sensitivity analysis of electricity fuel mix for the studied regions (12). All units are expressed as percentages.

| Region | Coal  | Oil  | Natural Gas | Nuclear | Hydro | Wind | Wood |
|--------|-------|------|-------------|---------|-------|------|------|
| MRO    | Minimum | 69.1 | 0.45 | 2.7 | 14.1 | 3.4 | 7.8 | 1.3 |
|        | Maximum | 70.3 | 0.87 | 5.4 | 15.4 | 4.1 | 3.0 | 1.5 |
| RFC    | Minimum | 60.2 | 0.50 | 7.9 | 26.4 | 0.5 | 0.7 | 0.9 |
|        | Maximum | 64   | 0.54 | 6.5 | 28.3 | 0.8 | 0.1 | 0.7 |
| SERC   | Minimum | 50.0 | 0.7  | 14  | 24.4 | 1.7 | 0.05 | 1.7 |
|        | Maximum | 57   | 0.8  | 16.8 | 26.5 | 3.8 | 0.05 | 1.7 |
| Parameter                          | Unit         | Reference | Minimum | Maximum |
|-----------------------------------|--------------|-----------|---------|---------|
| **Boone**                         |              |           |         |         |
| Soil carbon emission              | g CO2e/MJ    | 0.5       | -18.1   | 14.4    |
| HLFB application                  | g CO2e/MJ    | 25.2      | 0.1     | 50.1    |
| Fertilizer application           | g CO2e/MJ    | 25.2      | 0.1     | 50.1    |
| Soil N2O direct and indirect Emission | g CO2e/MJ | 3.4       | 0.1     | 7.3     |
| HLFB application                  | g CO2e/MJ    | 6.9       | -0.1    | 17.4    |
| Fertilizer application           | g CO2e/MJ    | 6.9       | -0.1    | 17.4    |
| **Queen Anne's**                 |              |           |         |         |
| Soil carbon emission              | g CO2e/MJ    | -1.05     | 24.5    | 25.4    |
| HLFB application                  | g CO2e/MJ    | 22.1      | -0.7    | 40.3    |
| Fertilizer application           | g CO2e/MJ    | 22.1      | -0.7    | 40.3    |
| Soil N2O direct and indirect Emission | g CO2e/MJ | 2.5       | -0.1    | 4.4     |
| HLFB application                  | g CO2e/MJ    | 3.8       | 1.3     | 5.2     |
| Fertilizer application           | g CO2e/MJ    | 3.8       | 1.3     | 5.2     |
| **Lenoir**                        |              |           |         |         |
| Soil carbon emission              | g CO2e/MJ    | -4.7      | -25.8   | 7.3     |
| HLFB application                  | g CO2e/MJ    | 17.2      | -8.2    | 42.2    |
| Fertilizer application           | g CO2e/MJ    | 17.2      | -8.2    | 42.2    |
| Soil N2O direct and indirect Emission | g CO2e/MJ | 2.2       | -0.1    | 4       |
| HLFB application                  | g CO2e/MJ    | 3.3       | 0.6     | 5.1     |
| Fertilizer application           | g CO2e/MJ    | 3.3       | 0.6     | 5.1     |
Sensitivity of results to electricity credit for onsite power production

Table 5S shows the result of a sensitivity analysis looking at the effect of change in the process yield as well as the electricity credit for the process where the electricity is produced onsite and is sold to the grid for the Boone, Iowa site. Results show the greater influence of electricity coproduct on the life cycle GHG emissions of the onsite power production scenario depicting that if the coproduced electricity does not displace the marginal electricity the loss of this credit for onsite power production scenario can result in almost doubling the life cycle GHG emissions. In all cases that do not include the electricity co-product credit, the resulting cellulosic ethanol would not meet RFS2 (14) criteria for a cellulosic biofuel as the life cycle GHG intensity estimated is above 37.2 g CO₂e/MJ, the threshold level required for a 60% reduction relative to the 2005 baseline GHG intensity of gasoline (93 g CO₂e/MJ).

Table 5S. Sensitivity of the net GHG results to electricity credit in onsite power production scenario

| Selling electricity (284 L/Mg CS) | Mean ethanol yield (306 L/Mg CS) | High ethanol yield (328 L/Mg CS) |
|-----------------------------------|----------------------------------|----------------------------------|
| Selling electricity               | 31                               | 35                               | 39                               |
| Not selling electricity           | 74                               | 68                               | 64                               |

Economic Analysis

Total Capital investment

The main difference between the three scenarios we compare is the boiler and power generation section of the biorefinery. As noted, the boiler in the ethanol biorefinery with onsite power production (modeled by Aden et al. (15) and Humbird et al. (1) has been replaced with a smaller boiler sized for the biorefinery’s steam requirements that is fed biogas produced onsite. Thus the boiler is much smaller in the HLFB land-amendment and coal substitution scenarios compared to the larger boiler and turbo generator equipment in design by Humbird et al. (1). In the coal substitution option, the HLFB is dried from 45% moisture to 20% moisture using a rotary dryer. Three dryers are considered for this purpose. In the HLFB option, storage costs for the HLFB are included in the capital cost.

The capital cost of the biogas boiler is taken from a natural gas boiler which is obtained from a quotation by Victory Engineering and the price of the rotary dryers are obtained from a quote by R. Simon (Dryers) Ltd (Table 6S). Cost for an enclosed concrete storage tank is included for 180
days of HLFB storage. The storage equipment is expected to be similar to storage of dewatered biosolids filter cake from wastewater treatment facilities that also apply high nutrient content biosolids to agricultural land. All other equipment costs are identical to costs specified by Humbird et al. (1) except the power production section (Table 7S).

**Table 6S-Lignin-land amendment and byproduct as coal substitute with coal scenarios equipment installed cost that are different from model by Humbird et al. (1).**

| Item                              | Source                     |
|-----------------------------------|----------------------------|
| Natural gas boiler                | Victory Engineering        |
| Rotary dryer                      | R. Simon (Dryers) Ltd.     |

**Table 7S-Total Installed Equipment Costs (2007 U.S.\$)**

| Process Area                        | Land Amendment | Coal Substitute | Onsite Power Production |
|--------------------------------------|----------------|-----------------|--------------------------|
| A100 (Feedstock Storage and Handling) | $24,200,000    | $24,200,000    | $24,200,000              |
| A200 (Pretreatment and Neutrilization) | $32,900,000    | $32,900,000    | $32,900,000              |
| A300 (Enzymatic hydrolysis and Fermentation) | $31,300,000    | $31,300,000    | $31,300,000              |
| A400 (Enzyme production)            | $18,700,000    | $18,700,000    | $18,700,000              |
| A500 (Recovery)                     | $22,300,000    | $22,300,000    | $22,300,000              |
| A600 Wastewater Treatment (WWT)     | $49,300,000    | $49,300,000    | $49,300,000              |
| A700 (Storage)                      | $40,000,000    | $5,000,000     | $5,000,000               |
| A800 (Boiler,)                      | $7,200,000     | $11,100,000    | $65,800,000              |
| A900 (Utilities)                    | $6,900,000     | $6,900,000     | $6,900,000               |
| Total Installed Equipment Cost      | $208,700,000   | $177,500,000   | $232,200,000             |

Table 7S shows the individual costs of each process area in 2007 U.S.\$. As can be seen from this table the main difference in equipment costs come from the boiler area (A800), and secondly from HLFB storage. Total project investment includes additional cost categories summarized in Table 8S from Humbird et al. (1), which were factored into the total capital cost for all the three scenarios.
Table 8S- Additional Costs for Determining Total Project Investment (Adapted from (15))

| Item                | Description                                                                                                                                                                                                                                                                                                                                 | Amount                                      |
|---------------------|---------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------------|---------------------------------------------|
| Warehouse           | Site Development: Includes fencing, curbing, parking, lot, roads, well drainage, rail system, soil borings, and general paving. This factor allows for minimum site development assuming a clear site, with no unusual problems such as right-of-way, difficult land clearing, or unusual environmental problems. | 1.5% of Total Installed Equipment Cost      |
| Site Development    |                                                                                                                                                                                                                                                                                                                                            | 9% of the installed cost of process equip. (areas A100, A200, A300, and A500).                  |
| Prorateable Costs   | This includes fringe benefits, burdens, and insurance of the construction contractor.                                                                                                                                                                                                                                                      | 10% of Total Installed Cost                 |
| Field Expenses      | Consumables, small tool equip. rental, field services, temporary construction facilities, and field construction supervision.                                                                                                                                                                                                         | 10% of Total Installed Cost                 |
| Home Office and Const. | Engineering plus incidentals, purchasing, and construction.                                                                                                                                                                                                                     | 25% of Total Installed Cost                 |
| Project Contingency | Small because of the detail included in the process design.                                                                                                                                                                                                                                                                             | 3% of Total Installed Cost                  |
| Other Costs         | Start-up and commissioning costs. Land, rights-of-way, permits, surveys, and fees. Piling, soil compaction/dewatering, unusual foundations. Sales, use, and other taxes. Freight, insurance in transit and import duties on equipment, piping, steel, instrumentation, etc. Overtime pay during construction. Field insurance. Project team. Transportation equipment, bulk shipping containers, plant vehicles, etc. Escalation or inflation of costs over time. Interest on construction loan. | 10% of Total Capital Investment             |

Table 9S shows the total project investment costs for land amendment, coal substitute and onsite power production scenarios.

Table 9S-Total Project Investment for land amendment, coal substitute and onsite power production scenarios (2007 U.S.$)

|                        | Land Amendment | Coal Substitute | Onsite Power Production |
|------------------------|----------------|-----------------|-------------------------|
| Direct Costs:          |                |                 |                         |
| Total Installed Equipment Cost | $208,700,000   | $177,500,000    | $232,200,000            |
| Warehouse              | $4,200,000     | $4,200,000      | $4,200,000              |
| Site Development       | $9,500,000     | $9,500,000      | $9,500,000              |
| Additional piping      | $4,700,000     | $4,700,000      | $4,700,000              |
| Indirect Costs:        |                |                 |                         |
| Field Expenses + Prorateable Expenses | $45,400,000 | $39,200,000 | $50,200,000 |
| Home Office & Construction Fee | $45,400,000 | $39,200,000 | $50,200,100 |
| Project Contingency    | $22,700,000    | $19,600,000     | $25,100,000             |
| Other Costs (Startup, Permits, etc.) | $22,700,000 | $19,600,000 | $25,100,000 |
| Fixed Capital Investment | $363,000,000  | $313,500,000    | $401,000,000            |
| Total Capital Investment | $383,000,000  | $331,100,000    | $422,900,000            |

Table 9S shows that the total project investment for the high lignin byproduct land amendment and coal substitute scenarios are about 40 and 90 million dollars less than the lignin boiler scenario (1), which gets
reflected in loan payments (at 8% borrowing) with the assumed 40% equity financing. This difference in project investment is also reflected in evaluating the depreciation costs.

Table 10S shows the detailed operating costs of the three scenarios.

**Table 10S- Operating cost for land amendment, coal substitute and onsite power production scenarios (2007 U.S.$)**

|                              | Land Amendment ($)/yr | Coal Substitute ($)/yr | Onsite Power Production ($)/yr |
|------------------------------|-----------------------|------------------------|--------------------------------|
| Feedstock + handling         | $45,200,000           | $45,200,000            | $45,200,000                    |
| Sulfuric Acid                | $1,500,000            | $1,500,000             | $1,500,000                     |
| Ammonia                      | $4,000,000            | $4,000,000             | $4,000,000                     |
| Glucose (Enzyme Production)  | $11,800,000           | $11,800,000            | $11,800,000                    |
| Other Raw Material Costs     | $7,500,000            | 7,500,000              | $7,500,000                     |
| Waste Disposal               | $1,500,000            | 1,500,000              | $1,500,000                     |
| Electricity                  | $12,900,000           | $12,900,000            | -6,600,000                     |
| Byproduct transportation     | $1,400,000            | $400,000               | N/A                            |
| Fixed Costs                  | $10,700,000           | $10,700,000            | $10,700,000                    |
| Capital Depreciation         | $10,200,000           | $10,500,000            | $13,400,000                    |
| Byproduct Credit             | -$10,800,000          | -$4,900,000            | N/A                            |
| Average Income Tax           | $7,500,000            | $7,500,000             | $7,500,000                     |
| Total operating cost         | $103,200,000          | $108,600,000           | $97,300,000                    |
| Amortized capital cost       | $22,000,000           | $19,000,000            | $24,500,000                    |
| Total amortized cost         | $125,400,000          | $127,600,000           | $121,400,000                   |

1Electricity is calculated based on the average industrial electricity prices for the state of Iowa for both cases reported by department of energy (16).
2The Iowa State Grain Truck Transportation Calculator is an interactive spreadsheet model found at [http://www.extension.iastate.edu/agdmg/crops/xls/a3-29graintransportation.xls](http://www.extension.iastate.edu/agdmg/crops/xls/a3-29graintransportation.xls)
3Not applicable
4Fixed costs are comprised of maintenance, insurance, taxes, and other expenses noted in Humbird et al. (1).
5Capital depreciation is calculated assuming 20 years of production for the biorefinery
6In the overall operating cost of the land amendment scenario no price for lignin as a land amendment was assumed. A break-even cost analysis for this scenario comparing onsite-power production suggests a cost of $65/ton for the lignin byproduct (with 45% moisture content) for the purpose of land amendment.
7The price of lignin the byproduct was determined based on its energy content and relative to the 2010 price of coal in the state of Iowa (17).
8Annual payment of loan with an equity of 40% (1)

**Location effect on Biorefinery Characteristics and Costs**

The biorefinery location will affect both its environmental and economic performance. At the state level, location will impact operating costs due to electricity, natural gas and coal prices, which subsequently also affects the income from selling the byproduct as a coal substitute to local coal-fired power plants. Location will also affect the price of the biomass feedstock which
includes the cost of chopping, baling the residue, on-farm hauling of bales, and fertilizer replacement (18). Figure 2S shows the change in operating cost of the ethanol plant established in different states for the land amendment, coal substitute and onsite power production scenarios. Variability in operating cost for the land amendment and onsite power production scenarios in different states is due to the electricity price differences in each state and the variability in operating cost for coal substitute scenario comes from the electricity and coal cost changes in different states. Operating cost throughout the different states ranges from $111,000,000 to $154,000,000 and from 97,300,000 to 142,000,000 for land amendment and coal substitution scenarios, respectively.

![Figure 2S: Operating cost changes due to change of location of the plant](image)

Location dependent factors such as climate, soil type, and land use history are critical in the HLFB soil amendment option where the interaction between the byproduct and the environment (soil and atmosphere) affects change in SOC and N₂O. Amending the soil with the HLFB can provide carbon and nutrients for the soil as well as being a means of carbon sequestration. Climate, temperature and moisture which vary throughout the US influence soil carbon storage. Temperature increases the biological activity which results in higher CO₂ release but this also depends on the material that is being decomposed. Ogle et al. (19) show that under different crop management practices such as long term cultivation, tillage or no-till management, tropical
climate soil can store more carbon than in temperate climate. They argue that the biochemical kinetics of the processes involved with (1) breakdown of soil organic matter (SOM) following cultivation, (2) formation of aggregates in soils after a change in tillage, and (3) increased productivity and C input with the implementation of a new cropping practice, are likely to occur at a more favorable rate under the temperature regimes of tropical regions and in more moist climatic conditions (19).

Feedstock type, composition and availability also vary by state and region. In order to investigate the effect of biorefinery location on environmental impacts and economics we evaluated three distinct sites that could meet residue supply needs for a 2000 dry metric ton per day facility and also minimize operating cost. In selecting of the sites lower operating costs (the locations were chosen from the top ten states having lowest operating costs per scenario). The sites selected were Boone County in Iowa, Queen Anne’s County in Maryland, and Lenoir in North Carolina. All of the sites can sufficiently supply biomass residue to satisfy the 2000 dry metric ton/day biorefinery requirement. Available corn stover, wheat straw, and barley straw and potential expanded winter crop production (20) from surrounding farmlands within a 50 mile radius of the biorefinery plant location, were considered as feedstocks for bioethanol production for these locations. We assume that 50% of corn stover and 75% of wheat and barley straw could be harvested. The composition of the feedstock at each location depends on the biomass available in those agricultural areas. The biorefinery feedstock for Boone in Iowa State is solely supplied by corn stover while it comprises 57% corn stover, 24% of Wheat straw and 19% of Barley straw in Queen Anne’s County in Maryland. Feedstock in Lenoir County in North Carolina is 41% corn stover, 32% wheat straw and 27% barley straw. The HLFB composition (carbon, nitrogen and lignin) and flow rate were calculated for the three feedstocks, and ethanol yields were assumed identical to that specified by Humbird et al. (1), in our base case scenarios, but were set to a more conservative yield (300±30) for the stochastic analysis. This yield range is expected to capture variability in glucan and xylan composition for mixes of three feedsocks, and pretreatment, hydrolysis, and fermentation differences expected at scale as described by Spatari et al. (4). The biogeochemical model DayCent was used to estimate N and C fluxes when amending the land with the HLFB or replacing N nutrients for the stover removal for power generation scenarios 2 and 3. Simulation results for HLFB land amendment at all three sites resulted in a lower loss of SOC than in the two power generation co-product scenarios. This demonstrates that using HLFB
not only minimizes the consumption of fertilizers and lowers the emission but additionally allows for near maintenance of SOC (Table 1S). Moreover, simulations for Lenoir County in North Carolina suggest additional storage of SOC and low N₂O emissions, which might, as Ogle et al. (19) state, be due to the climate of the region, thus potentially suggesting that the application of the byproduct for this location can be more effective than other selected regions. In addition, this region has the lowest GHG emission for all the studied scenarios. Overall, the biogeochemical GHG emission results (Table 7S) indicate that location has an important effect on the life cycle GHG emission of the biofuel production cycle, and some locations may be more favorable for siting the biorefinery than others.

**Comparison of Ethanol Biorefinery Design by Humbird et al. (1) and Aden et al. (15)**

The bioconversion technology examined in this paper consists of enzymatic hydrolysis and fermentation. Ammonia is used in the Aspen design by Humbird et al. (1) to increase the pH of the hydrolyzate. As well, the lignin fraction of feedstock is fed to the boiler along with the sludge from anaerobic digestion and biogas from wastewater treatment. In an earlier Aspen design by NREL (15) the same corn stover (2000 dry metric ton/day) was converted to ethanol through the same process with a slight difference in simultaneous saccharification and use of lime to raise the pH in the pretreatment and hydrolyzate conditioning step. Although both designs have the same feedstock input rate, the ethanol production rate in the NREL 2002 design (69 MMgal/yr) is higher than the NREL 2011 design (61 MMgal/yr). In the NREL 2002 model the concentrated syrup from the evaporator and the lignin streams (consisting of unconverted lignin and some of the cellulose and hemicellulose from the feedstock that will remain unconverted through the hydrolysis process) are fed to the combustor. Table 12S compares the HLFB characteristics of the NREL 2002 and 2011 designs. Biogas from wastewater treatment, which is high in methane, is fed to the boiler along with other streams in both of the models, but the magnitude of this flowrate is different. In the NREL 2002 model (15) 625 kg/hr of biogas containing 324 kg/hr methane goes to combustor while in the NREL 2011 model (1) significantly more (21,860 kg/hr) biogas is fed to the boiler, and it contains 5,378 kg/hr of methane. Therefore using the HLFB in the NREL 2002 model for either the land amendment or coal substitute case would result in remaining insufficient energy source from biogas for producing steam needs of the biorefinery. In this case as additional purchased natural gas (NG) would be needed to satisfy the steam
requirement of the biorefinery. A parallel analysis investigating the three options for the lignin by-product with the NREL 2002 design indicated higher net life cycle GHG emissions for the HLFB amendment case but slightly lower GHG emissions for the coal substitution case (Table 12S). Operating costs are significantly higher for the HLFB land amendment and coal substitution scenarios with the 2002 model compared to on-site power generation due to the need to purchase natural gas in addition to electricity (Table 13S). However, capital costs remain lower for land amendment and coal substitution compared to onsite power generation due to the smaller boiler without a turbo-generator.
Table 11S. High lignin byproduct characteristics of the NREL 2002 and 2011 designs

|                   | NREL 2002\(^1\) | NREL 2011\(^2\) |
|-------------------|------------------|------------------|
| Flow rate (kg/hr) | 84,215           | 36,537           |
| Carbon content (%)| 21.6             | 48               |
| Nitrogen Content (%)| 0.7             | 1.9              |
| Lignin (%)        | 16.8             | 26.9             |

\(^1\)Aden et al. (15)
\(^2\)Humbird et al. (1)

Table 12S. Environmental analysis results of the NREL 2002 and 2011 design\(^{1,2}\)

|                    | 2002 | 2011 | 2002 | 2011 | 2002 | 2011 |
|--------------------|------|------|------|------|------|------|
|                    | Land Amendment | Land Amendment | Coal Substitute | Coal Substitute | Onsite Power Production | Onsite Power Production |
| Feedstock          | 32.6 | 0    | 32.6 | 12.8 | 32.6 | 12.8 |
| Feed Transport     | 1.8  | 2    | 1.8  | 2    | 1.8  | 2    |
| Chemical & Enzymes | 7.5  | 5.9  | 7.5  | 5.9  | 7.5  | 5.9  |
| Boiler             | 58   | 40   | 58   | 40   | 99   | 122  |
| Fermentative CO\(_2\) | 35   | 45   | 35   | 45   | 35   | 45   |
| Electricity        | 13   | 49.7 | 13   | 49.7 | -7   | -22.3 |
| Byproduct Transport| 1    | 1.1  | 0.5  | 0.6  | 0    | 0    |
| Fuel transport & distribution | 0.9 | 1 | 0.9 | 1 | 0.9 | 1 |
| Ethanol Combustion | 71   | 71   | 71   | 71   | 71   | 71   |
| Carbon Sequestration (crop) | -208.7 | -234 | -208.7 | -234 | -208.7 | -234 |
| Soil loss          | 0    | 3.88 | 27   | 32.4 | 27   | 32.4 |
| Net GHG            | 12.1 | -2.3 | 38.6 | 32   | 59.1 | 40.5 |

\(^1\)All units are gCO2e/MJ of ethanol
\(^2\)Prices are for Iowa
Table 13S. Capital and operating cost analysis results of the NREL 2002 and 2011 design

| Scenarios            | 2002  | 2011  | 2002  | 2011  |
|----------------------|-------|-------|-------|-------|
|                      | Capital cost | Capital cost | Operating cost | Operating cost |
| Land amendment       | 131,200,000 | $383,000,000 | $177,000,000 | $125,400,000 |
| Coal Substitute      | 137,300,000 | $331,100,000 | $171,000,000 | $127,800,000 |
| Onsite Power production | 204,000,000 | $422,900,000 | $131,300,000 | $121,400,000 |

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