Integration in a depot-based decentralized biorefinery system: Corn stover-based cellulosic biofuel

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Abstract
The current or “conventional” paradigm for producing process energy in a biorefinery processing cellulosic biomass is on-site energy recovery through combustion of residual solids and biogas generated by the process. Excess electricity is then exported, resulting in large greenhouse gas (GHG) credits. However, this approach will cause lifecycle GHG emissions of biofuels to increase as more renewable energy sources (wind, solar, etc.) participate in grid-electricity generation, and the GHG credits from displacing fossil fuel decrease. To overcome this drawback, a decentralized (depot-based) biorefinery can be integrated with a coal-fired power plant near a large urban area. In an integrated, decentralized, depot-based biorefinery (IDB), the residual solids are co-fired with coal either in the adjacent power plant or in coal-fired boilers elsewhere to displace coal. An IDB system does not rely on indirect GHG credits through grid-electricity displacement. In an IDB system, biogas from the wastewater treatment facility is also upgraded to biomethane and used as a transportation biofuel. The GHG savings per unit of cropland in the IDB systems (2.7–2.9 MgCO₂/ha) are 1.5–1.6 fold greater than those in a conventional centralized system (1.7–1.8 MgCO₂/ha). Importantly, the biofuel selling price in the IDBs is lower by 28–30 cents per gasoline-equivalent liter than in the conventional centralized system. Furthermore, the total capital investment per annual biofuel volume in the IDB is...
much lower (by ~80%) than that in the conventional centralized system. Therefore, utilization of biomethane and residual solids in the IDB systems leads to much lower biofuel selling prices and significantly greater GHG savings per unit of cropland participating in the biorefinery system compared to the conventional centralized biorefineries.

**KEYWORDS**

biofuel, biofuel selling price, biomethane, coal-fired power plant, corn stover, ethanol, greenhouse gas, integrated depot-based decentralized biorefinery, supply chain

## 1 | Introduction

The U.S. Energy Security and Independence Act of 2007 mandates 61 billion liters of cellulosic biofuel production by the year 2022 (USGPO, 2007). However, U.S. cellulosic biofuel production reached about 0.9 billion liters in 2017 (USEPA, 2017). Current pilot-scale cellulosic biorefineries are based on a centralized system design, in which all the processes for producing biofuel are centrally located. Centralized biorefineries are relatively small scale (compared to petroleum refineries) due to the low bulk density of the feedstock, which precludes transportation over large distances. In contrast, pretreated, pelletized cellulosic feedstock in decentralized biorefining systems enables very large-scale biorefineries. In the decentralized (depot-based) system, cellulosic feedstock is shipped to local depot facilities within feedstock production areas. Biomass is pretreated and pelletized in these depots, and this network of small-scale depot facilities supplies pretreated pellets to a very large biorefinery.

Regardless of whether the biorefinery systems are decentralized (depot-based) or centralized, the currently proposed process energy approach in the cellulosic biorefinery system is based on on-site energy recovery through combustion of residual solids (e.g., lignin and sludge) and biogas in the cogeneration facility. Excess electricity is exported to displace grid-electricity. The capital investment costs for on-site energy generation facility account for 28%–34% of the total capital investment in both centralized and decentralized biorefinery systems (Humbird et al., 2011; Kim et al., 2018). Greenhouse gas (GHG) credits associated with the excess electricity are a major cause of reduced lifecycle GHG emissions of cellulosic ethanol fuels and equal approximately 6–22 g CO$_2$/MJ in the centralized biorefinery system (Kim et al., 2019) and 32–45 g CO$_2$/MJ in the decentralized (depot-based) biorefinery system (Kim et al., 2018). In this analysis, the GHG credits refer to avoided GHG emissions.

The large fraction of electricity derived from coal-fired power plants supplying the current grid is the primary reason for significant GHG credits derived from excess electricity in the cellulosic biofuel system. However, electricity derived from coal is steadily declining in the U.S. In contrast, electricity from natural gas and renewable energy sources (e.g., solar, wind, biomass, hydro, geothermal, etc.) is continuously increasing (US EIA, 2017a), resulting in reduced GHG emissions associated with the grid-electricity, compared to the immediate past. Thus in the future, cellulosic biofuels will likely receive fewer GHG credits from their excess electricity. This effect will tend to increase the future lifecycle GHG emissions of cellulosic biofuels.

To overcome this problem of grid-electricity dependency of the lifecycle GHG emissions of cellulosic biofuels, residual solids can be combusted in coal-fired boilers or used on croplands as a soil amendment, instead of being combusted on-site for energy recovery in the cellulosic biorefinery (Pourhashem, Adler, McAloon, & Spatari, 2013; Scown, Gokhale, Willems, Horvath, & McKone, 2014). Utilizing residual solids as a co-product (i.e., as a substitute for coal) can reduce lifecycle GHG emissions of cellulosic biofuels and capital costs compared to the on-site combustion of residual solids (Pourhashem et al., 2013; Scown et al., 2014). Pourhashem et al. (2013) show that utilization of residual solids as a soil amendment achieves the lowest lifecycle GHG emissions of biofuel compared with coal substitution or on-site combustion.

Lifecycle GHG emissions of biofuel produced in the depot-based decentralized biorefinery system are generally somewhat larger than those in the centralized biorefinery system due to external energy used in the depot facilities (Kim & Dale, 2015b,2016). However, utilizing residual solids as an energy coproduct (coal substitute) might lower overall lifecycle GHG emissions in the decentralized (depot-based) biorefinery system. Therefore, we investigate the effects of utilizing residual solids as a solid fuel in the depot-based decentralized biorefinery integrated with a coal-fired power plant (hereafter called an “integrated decentralized biorefinery”). Residual solids in the integrated decentralized biorefinery (IDB) are dried and then co-fired with coal either in the integrated coal-fired power plant or in coal-fired boilers elsewhere, depending on the size of the IDB. Biomethane from the wastewater treatment facility is upgraded to natural gas quality and utilized as a transportation biofuel.
We assume that the IDBs are located adjacent to high gasoline consumption areas (large urban areas) in the Midwest so that a large fraction of the biofuel produced can be consumed locally, thereby minimizing transportation costs. Corn stover is the cellulosic feedstock for biofuel in the IDB system. The IDB system modeled in this paper uses the rapid bioconversion with integrated recycle technology (RaBIT) to reduce enzyme loading in the enzymatic hydrolysis process (Jin et al., 2016; Jin, Gunawan, Uppugundla, Balan, & Dale, 2012). The RaBIT process carries out the initial enzymatic hydrolysis step for a limited time (24 h) to avoid the subsequent low-rate period and also recycles unhydrolyzed solids to the next round of enzymatic hydrolysis for further biomass conversion. The enzymes adsorbed on the unhydrolyzed solids (around 60% of the total added enzymes) are recycled so that enzyme loading for subsequent enzymatic hydrolysis is greatly reduced. The corn stover supply chains for each IDB are determined by minimizing the biofuel selling price (including ethanol and biomethane). It is assumed that ethanol and biomethane are sold at the same price on an energy basis. The results are compared to those obtained for the centralized and decentralized biorefinery systems.

2 | MATERIAL AND METHODS

2.1 | Corn stover availability and depot facility

About 66% of the corn stover produced in a corn-soybean rotation under historical tillage management practices in the Midwestern United States can be collected as a feedstock for the cellulosic biofuel system. The corn stover removal rate (66%) used in this analysis is higher than the removal rate suggested by Wilhelm, Johnson, Karlen, and Lightle (2007) to maintain soil organic carbon (SOC) level. However, Jones, Zhang, Reddy, Robertson, and Izaurralde (2017) show that the differences in GHG emissions per dry Mg due to SOC losses induced by corn stover removal at different removal rates are small. Furthermore, Karlen et al. (2014) show that there is only small difference of grain yield between a moderate corn stover removal and a high corn stover removal. A scenario with a stover removal rate of 33% is investigated in a sensitivity analysis to determine the effects of different stover removal rates on the biofuel system.

The county-level information on corn stover (e.g., grain yields, soil organic carbon (SOC) changes, GHG emissions, etc.) estimated by Kim et al. (2017) is used in this analysis. Grain yield, SOC changes, and soil nitrogen emissions were modeled at a 56 m spatial resolution using the Environmental Policy Integrated Climate (EPIC) model, and the county-level data were aggregated from the pixel-level results using a 50 year time horizon (Kim et al., 2017). The collection costs for corn stover are estimated based on the cost data for collecting and baling corn stover from field experiment data (at the W.K. Kellogg Biological Station in Michigan and at the Arlington Agricultural Research Station in Wisconsin) and literature (Adler, Grosso, & Parton, 2007; Edwards, 2014; Hess, Kenney, Ovard, Searcy, & Wright, 2009).

Depot facilities are assumed to be located at existing grain elevators in the U.S. Midwest (Kim & Dale, 2016; Kim et al., 2018). In this analysis, the depot facility locations are determined based on the following two assumptions: (1) the collection radius for the depot facilities is less than 16.1 km, and (2) the depot facility size ranges from 90 to 200 dry Mg/day. Over 1,200 grain elevators are considered as possible depot facility locations in this analysis. The total amount of corn stover available from the depot facilities in the depot-based decentralized system is about 78 Tg/year, representing about 71% of the total annual collectable corn stover in the U.S. Midwest. In the depot facility, baled corn stover is pretreated via the ammonia fiber expansion (AFEX™) technology (Teymouri, Laureano-Perez, Alizadeh, & Dale, 2005), and pretreated corn stover is dried and pelletized (Campbell et al., 2013). The external energy sources for processes in the depot facility are electricity and natural gas. The pretreated corn stover pellets are transported from depot facilities to a decentralized biorefinery by either truck or railroad, depending on the availability of rail service at the depot facilities and logistics costs.

2.2 | Integrated biorefinery locations and process

Twelve coal-fired power plants near large urban areas in the U.S. Midwest are selected as IDB locations based on the total population within an 80 km radius of the coal-fired power plant. The IDB/coal-fired power plant locations are: Will County, Illinois (Chicago, 472 PJ/year); Wayne County, Michigan (Detroit, 256 PJ/year); Washington County, Minnesota (Minneapolis, 178 PJ/year); Milwaukee County, Wisconsin (Milwaukee, 157 PJ/year); St. Louis County, Missouri (St. Louis, 147 PJ/year); Hamilton County, Ohio (Cincinnati, 132 PJ/year); Marion County, Indiana (Indianapolis, 125 PJ/year); Wyandotte County, Kansas (Kansas City, 120 PJ/year); Douglas County, Nebraska (Omaha, 56 PJ/year); Columbia County, Wisconsin (Dane, 50 PJ/year); Linn County, Iowa (Cedar Rapids, 31 PJ/year); Clay County, Minnesota (Fargo, 15 PJ/year).

The cities noted inside the parentheses are the adjacent large urban areas, and the numbers inside the parentheses are the energy values of the annual gasoline consumption within an 80 km radius of the IDB location. The regional gasoline consumption is estimated as a product of the population size within an 80 km radius of the IDB location and the U.S. gasoline consumption per capita (US EIA, 2017b). The characteristics of the individual power plants are summarized in the
Supporting information (see Table S4). The rail service used by the power plant is assumed to be shared with the IDB.

The Aspen Plus model developed by the National Renewable Energy Laboratory (NREL) (Humbird et al., 2011) is modified for this analysis by removing processes associated with pretreatment and the cogeneration facilities from the biorefinery. The biorefinery is reconfigured to accommodate the RaBIT process, including incorporating centrifuges in the enzymatic hydrolysis step. Unhydrolyzed solids are separated by centrifuges, and recycled to the enzymatic hydrolysis process. In addition to centrifuges, a rotary dryer for drying residual solids, a natural gas-fired steam boiler, and equipment to upgrade raw biogas to biomethane (pipeline quality renewable natural gas, RNG) are also added in the IDB. Residual solids are dried to about 20% moisture content via a rotary dryer. The natural gas steam boiler generates thermal energy for the biorefinery. Sugar conversion factors by enzymatic hydrolysis (kg of fermentable sugars/kg of dry pellets) for the AFEX-pretreated corn stover pellets are based on literature (Sarks et al., 2016), and ethanol yields from the pretreated corn stover pellets in the RaBIT process are about 324 L of ethanol/dry Mg. Biofuel yield in the IDB is 326 gasoline-equivalent liter/dry Mg, including 221 gasoline-equivalent liter/dry Mg of ethanol and 105 gasoline-equivalent liter/dry Mg of biomethane.

Because of equipment limitations, only a portion of the residual solids from the large-scale IDBs can be co-fired with coal in the adjacent coal-fired power plant. The remaining residual solids are exported to coal-fired boilers elsewhere to displace additional coal. The fraction of residual solids co-fired in the adjacent coal-fired power plant varies with the biorefinery size and the capacity of the power plant. In this analysis, the co-firing limit for residual solids is assumed to be 15% on an energy basis (Scown et al., 2014).

2.3 Minimum biofuel selling price

The price of pretreated pellets estimated by Kim et al. (2018) is used in this analysis. The minimum biofuel selling price (MBSP) is estimated by regression equations based on results from the modified Aspen Plus model (see Figure S1). The equipment costs for additional equipment (i.e., centrifuge, rotary dryer and natural gas steam boiler) are obtained from an Aspen Plus model for a corn dry mill (USDA, 2016). The costs for the biogas upgrading equipment have been estimated based on an NREL report (Saur & Jalalzadeh-Azar, 2010). The cost year is 2013, and the relevant costs are updated with the producer price index (https://www.bls.gov/ppi/) or the chemical engineering plant cost index (http://www.chemengonline.com/pci-home). The 2013 fuel prices in the Annual Energy Outlook (US EIA, 2013a) (i.e., natural gas and electricity) are used. The selling price of residual solids is assumed to be 20% below the price of coal (on an energy basis) to offset the additional costs for co-firing in the power plant (e.g., equipment retrofits, etc.) (Pourhashem et al., 2013; USDOE, 2004). The U.S. annual electric utility data (US EIA, 2013b) provide the cost of coal used by each power plant. The selling price of residual solids exported to co-fired boilers elsewhere is equal to 80% of the U.S. coal price at the mine site.

2.4 Life cycle analysis

The functional unit in the biofuel production system is defined as one megajoule of biofuel. The system boundaries in the lifecycle GHG emissions of biofuel include corn stover collection, transportation and storage of baled corn stover, the depot facility, transportation of pretreated pellets, the IDB, displaced coal, transportation and distribution of biofuel, combustion of biofuel, and relevant upstream processes. The GHG emissions of corn stover production are obtained from Kim et al. (2017). In this study, marginal analysis was used to assign SOC changes over the entire soil profile and also soil N2O emissions to corn stover. The process data estimated for the depot (Kim et al., 2018) are used to calculate GHG emissions associated with the depot. The GHG emissions associated with the IDB and energy consumption (i.e., electricity and thermal energy) are estimated based on the mass and energy balance resulting from the modified Aspen Plus model, and the GHG emissions associated with biomethane losses (assumed to be 1%, Saur & Jalalzadeh-Azar, 2010) are also included.

The GHG credits from residual solids co-fired with coal in the adjacent power plant are equal to the lifecycle GHG emissions of coal combusted in the adjacent power plant, including GHG emissions of mining, transportation, and combustion in the power plant (NREL, 2012; USEPA, 2009). In contrast, no GHG emissions associated with transportation of coal are included in the GHG credits from residual solids co-fired elsewhere with coal in coal-fired boilers. The lifecycle GHG emissions of coal combustion from the U.S. lifecycle inventory (LCI) database (NREL, 2012) are modified in calculating the GHG credits from residual solids co-fired with coal in coal-fired boilers elsewhere. GHG emissions associated with the upstream and the downstream processes (e.g., diesel, electricity, natural gas, materials, transportation and distribution of biofuel, combustion of biofuel, etc.) are derived from the literature (Argonne National Laboratory, 2017; NREL, 2012; USEPA, 2010). GHG emissions associated with electricity consumed in the biorefinery system (including depot facilities and the biorefinery) are equal to either the GHG emissions of marginal electricity or the GHG emissions of the grid-electricity, depending on the total electricity demand in the corn stover-based biofuel system, as described below.
2.5 | Description of the biorefinery systems being compared

Three different biorefinery configurations are also investigated to provide relevant comparisons to the IDB system, namely: the IDB system without RaBIT (system B), the conventional depot-based decentralized biorefinery system (system C), and the conventional centralized biorefinery system (system D) (see Figure S2). By “conventional” we mean that all the residual solids and biogas produced by the system are combusted on-site to produce process heat and electricity, and the excess electricity is exported to the grid. The reference system, the IDB system with RaBIT, is denoted as system A. The ethanol yield in systems B and C is 313 L/dry Mg (Kim et al., 2018), and the ethanol yield in the centralized biorefinery system is 327 L/dry Mg (Humbird et al., 2011). The MBSP and lifecycle GHG emissions in the centralized biorefinery system are estimated based on the Aspen Plus model developed by the NREL (Humbird et al., 2011), while the MBSP and lifecycle GHG emissions associated with the conventional depot-based decentralized biorefinery system are estimated based on Kim et al. (2018). The MBSP and lifecycle GHG emissions in system B are estimated by methods similar to those used in system A.

It is assumed that the decentralized biorefineries in systems B and C follow the same supply chains determined in system A. In the centralized biorefinery system (D), local storage facilities are assumed to be located at the existing grain elevators, while the centralized biorefinery is located at the centroid of the county. Baled corn stover is transported by truck from farms to a local storage facility. The collection radii of the local storage facilities are assumed to be less than or equal to 16.1 km. Based on the county-level corn stover availability, over 1,300 local storage facilities are available to the centralized biorefinery system.

It is assumed that all the farmers within the collection radius of the local storage facility participate in supplying baled corn stover to the local storage facility. The local storage facility sizes range from 74 to 200,235 dry Mg/year. The smallest local storage facility is located in Pine County, Minnesota, where the available corn stover density is 0.09 Mg/km², while the average available corn stover density in the Midwest is 84 Mg/km². The total amount of corn stover available from the local storage facilities in the centralized system is about 73 Tg/year, or approximately 67% of the total collectable corn stover in the U.S. Midwest.

Contrast, farmers in the centralized biorefinery system receive their economic benefits directly from selling untreated corn stover. The farm-gate price of corn stover in the centralized biorefinery system includes profit in addition to the corn stover collection costs. Based on the farm-gate price and the quantity of corn stover forecasted in the 2016 Billion-Ton Report (USDOE, 2016), about 36% of the corn stover collection costs are assumed to be added to the farm-gate price as profit in the centralized biorefinery system. The farm-gate price of corn stover in the U.S. Midwest is US$ 44/dry Mg and 75 Tg at US$ 55/dry Mg (USDOE, 2016).

2.6 | Corn stover supply chain systems

The corn stover supply chain for a biorefinery is determined by minimizing the biofuel selling price for a given biorefinery within constraints (see Equations (1) and (2)). In the IDB system, the minimum size of the commercial decentralized biorefinery (700 dry Mg/day) is the only constraint. The centralized biorefinery system has two separate constraints: biorefinery size and collection radius. The biorefinery size in the centralized system is between 700 and 2000 dry Mg/day, and the collection radius is less than the maximum distance for a daily trip by truck (~354 km). It is assumed that a depot facility in the IDB system supplies pretreated pellets to only one IDB and a local storage facility in the centralized biorefinery system also supplies baled corn stover to one centralized biorefinery.

The supply chains in the IDB system are determined by Equation (1).

Objective function: Minimize MBSP

Constraint: \[ S_k \geq S_{\text{min}} \] (1)

where MBSP is the minimum biofuel selling price (US$/L), which is a function of the biorefinery size, the delivered cost of pellets, and the characteristics of the adjacent coal-fired power plant (e.g., thermal input, coal price, etc.). The biofuel selling price in each IDB is estimated by regression equations (see Figure S1). Size is the biorefinery size (dry Mg/day) and is calculated by Equation (3). \( S_{\text{min}} \) is the minimum commercial scale, 700 dry Mg/day. Subscript \( k \) is the \( k \)th biorefinery in the IDB system.

The supply chains in the centralized biorefinery system are determined by Equation (2).

Objective function: Minimize MBSP

Constraints:

\[ S_{\text{min}} \leq S \leq S_{\text{max}} \]

\[ r_{d_{k,j}} \leq R_{\text{max}} \] (2)
where subscript \( n \) represents the \( n \)th biorefinery in the centralized biorefinery system. \( S_{\text{max}} \) is the upper limit of the centralized biorefinery size (=2,000 dry Mg/day) based on baled corn stover. \( d_{kj} \) is the road distance between the \( n \)th centralized biorefinery and the \( j \)th local storage facility. \( R_{\text{max}} \) is the upper limit of the collection radius, which is equal to a daily round trip by truck (~354 km). The minimum biofuel (ethanol) selling price in the centralized biorefinery system is a function of the biorefinery size and the delivered cost of feedstock, and is estimated by the regression equation used in Kim et al. (2019). The biorefinery size, denoted “Size,” is:

\[
\text{Size}_k = \sum_j p_{kj} \cdot a_{kj} \cdot M_j \cdot (1 - f_{\text{loss}})
\]

(3)

where \( p_{kj} \) is the participating integer of the \( j \)th depot (local storage) in the \( k \)th decentralized (centralized) biorefinery. \( a_{kj} \) is the availability integer of the \( j \)th depot (local storage) for the \( k \)th decentralized (centralized) biorefinery. \( a_{kj} = 0 \) when the \( j \)th depot (local storage) already participates in supply chains for the previous biorefineries. Otherwise, \( a_{kj} = 1 \). \( M_j \) is the size of the \( j \)th depot (local storage) (dry Mg/day). \( f_{\text{loss}} \) is the fraction of dry mass lost during transportation, assumed to be 2% loss regardless of the feedstock format (Argonne National Laboratory, 2017). The minimization function in both systems is solved by mixed integer nonlinear programming algorithms.

Previous studies (Kim & Dale, 2016; Kim et al., 2018) show that the sequence of the biorefineries affects the overall supply chain system. Following the energy demand-oriented supply chain approach (Kim & Dale, 2016), the first supply chain is assumed to be established for an IDB located in the Chicago area, the highest gasoline consumption area among the urban areas considered here. The next supply chain is established for an IDB in the Detroit area. The sequence of the remaining supply chains follows the respective regional gasoline consumption levels.

In contrast, the sequence of the supply chains in the centralized biorefinery system follows the county-level corn stover availability. The first biorefinery in the centralized biorefinery system is assumed to be located in the county with the most available corn stover. The second biorefinery is located in the county with the next most available corn stover, excluding counties already participating in the supply chain for the first biorefinery. The rest of the biorefineries follow the same pattern by selecting among remaining counties, that is, counties not participating in previously assigned supply chains.

### Results

#### 3.1 Integrated decentralized biorefineries

Twelve integrated decentralized biorefineries (IDBs) located in the U.S. Midwest can process about 98% of the pretreated pellets available at depot facilities and can produce about 21.9 billion gasoline-equivalent liters (5.8 billion gasoline-equivalent gallons) of corn stover-based biofuel per year. Note that the biofuel volume is expressed as gasoline-equivalent volumes hereafter. The annual biofuel production in the individual IDBs ranges from 0.5 to 3.63 billion liters (with an average volume of 1.83 ± 1.04 billion liters, 0.13–0.96 billion gasoline-equivalent gallons). The energy value of the products of the individual IDBs ranges from 22 to 65 PJ/year (see Table 1), and the energy-equivalent fractions of the three biofuels produced (ethanol, biomethane, and residual solids) are 47%, 22%, and 31%, respectively. The transportation biofuels (ethanol and biomethane) produced in most IDBs could be consumed within an 80 km radius, thereby reducing biofuel distribution costs.

Between 29 and 169 depot facilities supply pretreated pellets to the individual IDBs (see Figure S3). The largest IDB is located in the Minneapolis area, which is also the third highest gasoline-consuming area among the urban areas investigated. A total of 169 depot facilities supply the pretreated pellets to this particular IDB, and most of these depot facilities are located in Iowa and Minnesota (see Figure S3). Table 1 summarizes the characteristics of each of the 12 IDBs.

#### 3.2 Biofuel selling price

The MBSP values in the IDB system are US$ 0.65–0.86/L (gasoline-equivalent liter) with a volume-weighted average MBSP of US$ 0.73 ± 0.06/L. The delivered cost of feedstock (including pellet and logistics costs) to the IDB accounts for about 65%–74% of the biofuel selling price, US$ 0.46–0.63/L (see Figure 1). The credits for the combustion value of the residual solids are around US$ 0.02/L. The external energy costs in the biorefinery (i.e., electricity and natural gas) are US$ 0.08–0.09/L. The biorefinery costs (including material costs, equipment investment, ROI, and other costs in the biorefinery) range from US$ 0.13 to 0.20/L, depending on the biorefinery size. The IDB located in the Minneapolis area has the lowest costs of production, while the highest production costs are for the biorefinery located in the Cincinnati area.

The logistics costs in the IDB system are US$ 0.05–0.15/L. Over 25% of the pretreated pellets processed in the IDBs (except for the biorefineries in the Cincinnati and the Fargo areas) are transported by railroad. The highest logistics costs are observed for the IDB located in the Cedar Rapids area, in which the mass-weighted collection radius for trucks is about 503 km, longer than the mass-weighted collection radii for trucks in other IDBs.
3.3 | Lifecycle GHG emissions

The lifecycle GHG emissions of corn stover-based biofuel in the IDB system are 28–40 g CO₂/MJ if marginal electricity is assumed for the IDBs and the associated depot facilities. The fuel mixes in the marginal electricity case are 44% natural gas and 56% renewable resources (i.e., hydro, geothermal, solar, wind), based on the electricity projections in the Power Sector Modeling Platform from the U.S. Environmental Protection Agency (USEPA, 2015). When the state electricity grid (instead of marginal electricity) is assumed to provide electricity in the IDB system, the lifecycle GHG emissions of biofuel increase by 20%–38%, and range from 39 to 58 g CO₂/MJ.

The IDB system (including depot facilities and biorefinery) consumes between about 0.7% and 7.5% of the total electricity generated in a given state. About 54% of the total electricity demand in the IDB system is associated with the biorefinery, and the rest of the electricity demand is due to electricity consumed in the depot facilities. The annual electricity demand of the IDB system is greater than the state average electricity generation for a single power plant (see Table S5). Each state in the Midwest would therefore likely build new power plants to meet the additional electricity demand from the IDB system. The energy source in newly built power plants would be either natural gas or renewable resources, in other words, marginal electricity. The lifecycle GHG emissions of corn stover-based biofuel in the individual IDBs are listed in Table 1. The volume-weighted average lifecycle GHG emissions of biofuel in the IDB system are 33.6 ± 3.6 g CO₂/MJ.

Figure 2 summarizes GHG emissions of corn stover biofuel in the IDB system. GHG emissions associated with the pretreated pellets are the major GHG source in the lifecycle GHG emissions of corn stover biofuel. Most GHG emissions of the pretreated pellets are due to carbon dioxide releases.
ural gas consumption in the biorefinery are 19.3 g CO2/MJ, depending on the biorefinery size, while GHG emissions due to the logistics involved are 5.6 g CO2/MJ, and GHG emissions during storage are 3.7 g CO2/MJ. The GHG emissions of natural gas consumption in the depot facility are 16 g CO2/MJ. The GHG emissions associated with soil N2O are negative (−12 to −2 CO2/MJ) because no replacement nitrogen nutrients are needed in the corn-soybean rotation (Kim et al., 2017). The GHG emissions associated with diesel consumption in collecting and baling corn stover range from 2.6 to 3.1 g CO2/MJ, and GHG emissions during storage are 3.7 g CO2/MJ. The GHG emissions of transportation of the baled corn stover are 0.3–0.4 g CO2/MJ, while GHG emissions due to transportation of the pretreated pellets are 0.8–2.8 g CO2/MJ.

The biorefineries considered here consume marginal electricity at 6.6 g CO2/MJ. The GHG emissions of natural gas consumption in the biorefinery are 19.3 g CO2/MJ. The GHG credits associated with residual solids are 45.8–50.2 g CO2/MJ, depending on the biorefinery size, the capacity of the adjacent power plant and the type of coal it consumes. The GHG credits from residual solids displacing coal in the adjacent power plant range from 1.6 to 45.8 g CO2/MJ. All residual solids from the IDB in the Cincinnati area are co-fired with coal in its adjacent power plant; hence the GHG credits from this portion of residual solids are the highest of all the biorefineries modeled in this paper. The GHG credits of the remaining residual solids co-fired with coal elsewhere are 0.0–48.5 g CO2/MJ. Despite larger GHG credits from the utilization of residual solids as a soil amendment in the centralized system (Pourhashem et al., 2013), the location of the IDBs (adjacent to urban area) could limit the use of residual solids as a soil amendment due to the logistics involved.

3.4 | Comparisons

The different biorefinery systems (A, B, C, and D as defined above) are compared in Table 2. Biofuel yields in these four corn stover biorefinery systems range from 213 to 336 L/dry Mg. The fraction of ethanol in the overall biofuel produced (which consists of both ethanol and biomethane) is 68% in system A, 63% in system B, and 100% in systems C and D. Despite lower ethanol yields, system B achieves the highest overall biofuel yield. Lower ethanol yields in system B lead to less fermentable sugars converted to ethanol, resulting in more biomethane and residual solids. System B produces 3% less ethanol than system A does, but 17% more biomethane and 7% more residual solids.

In the conventional centralized biorefinery system (D), 95 centralied biorefineries are established in the U.S. Midwest (see Figure S4). The centralized biorefineries located in Illinois, Iowa, Minnesota, and Nebraska produce over 66% of the total ethanol fuels produced in the centralized biorefinery system. The annual biofuel (ethanol) production in the individual centralized biorefineries is 0.06–0.16 billion liters, and the total biofuel volume in the centralized biorefinery system is 14.2 billion liters/year. The biofuel selling prices in the centralized biorefinery system are US$ 0.97–1.49/L, and the lifecycle GHG emissions are 9.8–58.1 g CO2/MJ.

The IDB systems (A and B) yield the lowest biofuel selling price among the systems considered. The biofuel selling price in the IDB systems is 27%–29% lower than that in the centralized biorefinery system (D), and all the biofuels produced in the IDB systems are priced below the lowest prices achieved in the centralized biorefinery system. The differences in the biofuel selling price between system A and system B are very small; hence, the effects of RaBIT on the biofuel price are not significant due to the relatively positive trade-off between ethanol production and biomethane production. In contrast, utilization of biomethane and residual solids can reduce biofuel selling price by 27% compared to the case in which only ethanol is produced.

The production costs (including costs for feedstock, materials, fuel and equipment, labor, return on investment, and others) in the corn stover-based biorefinery are US$ 0.75–1.08/L. The delivered cost of feedstock (including pellet and logistics) in the depot-based decentralized biorefineries is 65%–71% of the production costs, while only 39% of the production costs in the centralized biorefineries are for the delivered cost of feedstock. A “mature” process is characterized by feedstock costs amounting to about 70% of total production costs.

The material costs in the corn stover-based biorefinery range from US$ 0.06 to $ 0.17/L, and over 50% of the material costs are associated with glucose consumed during enzyme production, US$ 0.04–0.10/L. Due to the lower enzyme loadings achieved in the RaBIT process, the decentralized
biorefineries in system A have the lowest material costs of the systems considered. The credits (including credits from excess electricity and residual solids if applicable) are US$ 0.02–0.09/L. The depot-based decentralized biorefineries in system C exhibit the highest credits, followed by the centralized biorefineries in system D.

The total capital investment per annual biofuel volume in the corn stover-based biorefinery systems is US$ 0.54–2.95/L. The biorefineries in system D have the highest total capital investment per annual biofuel volume due to the relatively small-scale biorefineries that result from poor logistic properties of baled corn stover and the need for additional equipment for pretreatment and cogeneration in the biorefinery. The biorefineries in the IDB systems have lower total capital investment per annual biofuel volume. The utilization of biomethane and residual solids in systems A and B can reduce capital investment in boilers. However, the IDBs in systems A and B require external energy costing about US$ 0.09/L.

The lifecycle GHG emissions in the IDB systems (A and B) are lower than those in the centralized biorefinery system (D) (see Table 2). Utilization of biomethane and residual solids in the depot-based decentralized biorefinery system can reduce the lifecycle GHG emissions by 35%–40% compared to system C. The lifecycle GHG emissions in system B are slightly lower (6%–8%) than those in system A because of larger GHG credits from residual solids. The volume-weighted GHG credits from residual solids are 49.9 ± 0.8 g CO₂/MJ in system A and 51.5 ± 0.8 g CO₂/MJ in system B. The GHG credits from the excess electricity in systems C and D are 29.4 ± 6.6 g CO₂/MJ and 13.2 ± 3.9 g CO₂/MJ, respectively. The GHG credits after subtracting GHG emissions of external energy in the IDBs (i.e., electricity and natural gas) are greater than the GHG credits from the excess electricity in systems D, 23.7 ± 0.8 g CO₂/MJ in system A and 26.0 ± 0.8 g CO₂/MJ in system B.

A lower corn stover removal rate (33%) increases the projected biofuel selling price by 12%–15% compared to a stover removal rate of 66% due to higher farm-gate price of corn stover and reduced capacity of the biorefinery in the decentralized biorefinery system. The state electricity grid (instead of marginal electricity) provides electricity for the IDB system in some states (e.g., Kansas, Missouri and etc.). The annual electricity demand of the IDB system in those states is less than the state average electricity generation for a single power plant. The IDB systems provide better performance compared to the conventional centralized biorefinery system, even when about 33% of the corn stover is collected as a feedstock for the cellulosic biofuel system.

| TABLE 2 | Comparison of the four biorefinery systems studied [System A: integrated decentralized system with RaBIT; System B: integrated decentralized system without RaBIT; System C: conventional depot-based decentralized biorefinery system; System D: conventional centralized biorefinery system] |
| | Unit | System A | System B | System C | System D |
| Number of biorefineries in the U.S. Midwest | 12 | 12 | 12 | 95 |
| Biorefinery capacity<sup>a</sup> billion liters/year | 1.83 (±1.04) | 1.88 (±1.08) | 1.19 (±0.68) | 0.15 (±0.02) |
| Overall biofuel production billion liters/year | 21.91 | 22.58 | 14.31 | 14.22 |
| Biofuel yield<sup>a</sup> liter/dry Mg | 326 | 336 | 213 | 222 |
| Ethanol yield liter/dry Mg | 220 | 213 | 213 | 222 |
| MBSP<sup>b</sup><sub>e</sub> $/L | 0.73 (±0.06) | 0.75 (±0.05) | 1.03 (±0.09) | 1.03 (±0.06) |
| Production costs<sup>c</sup><sub>e</sub> $/L | 0.75 (±0.05) | 0.78 (±0.06) | 1.13 (±0.09) | 1.08 (±0.06) |
| Credits from co-product<sup>d</sup><sub>e</sub> $/L | 0.02 | 0.02 | 0.09 | 0.05 |
| Total capital investment per annual biofuel volume<sup>e</sup> $/L | 0.54 (±0.1) | 0.56 (±0.09) | 1.17 (±0.21) | 2.95 (±0.19) |
| Lifecycle GHG<sup>e</sup> g CO₂/MJ | 33.57 (±3.6) | 31.08 (±3.5) | 52.02 (±6.8) | 35.41 (±8.8) |
| Overall GHG savings Tg CO₂/year | 40.8 | 43.8 | 18.38 | 25.65 |
| GHG savings per unit of biofuel<sup>e</sup> g CO₂/MJ | 59.51 (±3.6) | 62.0 (±3.5) | 41.06 (±6.8) | 57.67 (±8.8) |
| GHG savings per unit of cropland<sup>e</sup> Mg CO₂/ha | 2.66 (±0.39) | 2.86 (±0.40) | 1.20 (±0.24) | 1.74 (±0.44) |
| GHG savings per unit of corn stover consumed<sup>e</sup> kg CO₂/dry Mg | 533 (±32.1) | 573 (±32.2) | 241 (±40.0) | 353 (±54.1) |

<sup>a</sup>Including ethanol and biomethane. <sup>b</sup>Biofuel selling price = Production costs—Credits from co-product (i.e., electricity or residual solids if applicable). <sup>c</sup>Including costs for feedstock, material, fuel, capital investment, labor, return on investment, and others. <sup>d</sup>Including credits from excess electricity and residual solids if applicable. <sup>e</sup>Volume-weighted averages.
Systems A and B reduce overall GHG emissions by 41–44 Tg CO₂/year, while systems C and D can save 18–26 Tg CO₂/year. The IDB systems reduce GHG emissions per unit of corn stover consumed by about 1.5–1.6 fold more than does the centralized biorefinery system. However, the GHG savings per unit of biofuel or per unit of corn stover does not take into account the land-use efficiency of the different biorefinery systems (i.e., the volume of biofuel produced per hectare). Cropland is a scarce resource and is a principal constraint in the overall biofuel system. The GHG savings per unit of cropland (the ratio of the GHG savings by a biorefinery to the total cropland involved in its supply chain) show how much GHG emissions can be reduced per hectare of cropland involved in the supply chain for a given biorefinery, (i.e., land-use efficiency in terms of GHG savings). The two IDB systems (A and B) achieve much higher GHG savings per area of cropland than do the conventional centralized biorefinery systems.

In order to assess the GHG savings of the biorefineries, Figure 3 shows the different types of GHG savings associated with the individual biorefineries and their lifecycle GHG emissions. Biofuel in Area α of the figure has two important properties: (1) lower biofuel selling price and (2) greater GHG savings (or lower lifecycle GHG emissions). Over 90% of the biofuels produced in systems A and B, amounting to about 20 billion liters (see Table S6), are in Area α of this figure regardless of how the GHG savings are quantified. Only 1.24–2.33 billion liters of biofuels in system D are in Area α, accounting for 9%–16% of the total biofuel volume produced in system D. No biofuels in system C are found in Area α. All the biofuel volumes produced in the IDB systems are located in Areas α and β, while about 80% of the biofuels in the centralized system (~11 billion liters) are in Areas γ and δ.

4 | DISCUSSION

Utilization of biomethane and residual solids in the IDB (depot-based) systems leads to significantly lower biofuel selling prices compared to the conventional centralized
biorefineries. The biofuels produced in the IDB systems are equivalent to 12%–101% of the regional gasoline consumption (within an 80 km radius). About 79 centralized biorefineries (of 95 in total) produce more biofuel than the gasoline volume (on an energy basis) consumed in their counties, and those “surplus” biofuels account for 60% of the total biofuels produced in the centralized biorefinery system. Surplus biofuels would probably need to be exported from the counties in which they were produced. In addition, biofuels produced in the IDB systems would have lower logistics costs than biofuels produced in the centralized biorefinery system, leading to lower prices at the pump. The IDB systems also offer a much lower capital investment per annual unit of biofuel produced, and thus would likely be more attractive to investors. Furthermore, the IDB systems more effectively utilize croplands to reduce overall GHG emissions and can supply less-GHG intensive biofuels at lower prices than can the centralized biorefinery systems.

It is likely that optimal biorefinery systems will vary somewhat by region. For example, the IDBs in Michigan and Wisconsin can produce biofuels in Area α of Figure 3 (low cost/low GHGs), while either the integrated decentralized or the centralized biorefinery systems can probably produce biofuels in Area α in the northern or central parts of Illinois (see Figures S6–S7). Therefore, an optimized biorefinery system in a given region should be determined based on the relevant regional conditions (e.g., corn stover availability, farm-gate price of biomass, SOC changes, etc.). As we have shown in past work (Kim & Dale, 2015a), “all biomass is local.”

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AUTHORS’ CONTRIBUTIONS

SK, BED, RCI, and TR conceptualized and designed the research. SK, MJ, XZ, ADR, MS, and KDT performed the research. SK and BED analyzed the data. SK, BED, MJ, XZ, PM, CDJ, RCI, and VB wrote the manuscript.

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SUPPORTING INFORMATION

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