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ORIGINAL PAPER

# Quantifying the greenhouse gas emissions abatement cost of biomass co-firing in coal-powered electricity generation

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## Abstract

This paper analyzes the abatement costs associated with greenhouse gas reductions achievable by co-firing corn stover with coal at 71 coal-fired, utility-scale power plants in the Midwestern USA. The cost per metric ton of abated $CO_2$-equivalents is estimated using facility-specific supply functions for corn stover assuming best carbon management practices, county-level corn production data, a life cycle inventory tool for calculating biomass feedstock emissions, and simplified cost models for coal and co-fired capital and operating costs. Abatement costs vary substantially across the power plants modeled: mean costs were $123.71 per metric ton $CO_2$-eq at a 5% co-firing rate, $64.43 for 10% co-firing, and $49.20 for 20% co-firing, with coefficients of variation of 26%, 38%, and 48%, respectively. Lower abatement costs are primarily associated with high co-firing rates and high estimated unit costs for coal. The local corn yield and collection radius do not appear to have a substantial impact on estimated abatement costs. This advances our understanding of the abatement costs associated with co-firing biomass and coal, and the drivers of variability in abatement costs, by modeling feasible production scenarios using actual power plant and corn production data instead of idealized scenarios.

**Keywords** Biomass co-firing · Climate change mitigation · Corn stover · Emissions abatement · Greenhouse gas emissions

## Introduction

Electricity generation in coal-fired power plants is responsible for approximately one-quarter of greenhouse gas (GHG) emissions in the USA; in 2016, coal produced one-third of the country's electricity but two-thirds of the GHG emissions associated with power generation (US Environmental Protection Agency 2018). Several studies have explored the potential cost-effectiveness of co-firing biomass in existing coal-fired plants to reduce their emissions profile, identifying a wide range of abatement costs over varied scenario assumptions (Ortiz et al. 2011; Wilson et al. 2012; McGlynn et al. 2014; Schakel et al. 2014; Djomo et al. 2015). Many policies, such as the Clean Power Plan and federal Renewable Fuel Standards, have identified biomass as a potential source of emissions reductions in the electricity and transportation fuels sectors. As of 2020, 30 states have developed their own Renewable Portfolio Standards, many of which address the potential for utilizing biomass to reduce GHG emissions (National Conference of State Legislatures 2020).

However, the life cycle emissions associated with biomass can vary greatly. They depend on factors such as the choice of biomass feedstock, prior land use, geographic location, and indirect land use change implications (Farrell et al. 2006; Curtright et al. 2012; Johnson et al. 2013). With respect to the cost of abating emissions, incremental capital and operating costs are needed to repower boiler systems and process biomass for co-firing. Resource availability also plays a major role in determining the cost of co-firing; in addition to direct feedstock expenditures, a larger collection area increases transportation costs.

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As a result, there is significant scenario uncertainty in the abatement costs associated with co-firing GHG emissions reductions. Abatement costs may vary substantially by individual power plants due to differences in local resource availability and boiler capacity, even for the same feedstock and co-firing rate. This study estimates abatement costs associated with co-firing corn stover for 71 coal-fired Midwestern power plants in the Midcontinental (MISO) power region. The location and size (net MWh produced in 2016) are shown in Fig. 1. Estimated abatement costs are based on integration of spatially explicit supply curves for biomass available for sourcing to each power plant, a life cycle inventory tool to estimate GHG emissions, and a simplified model of non-fuel co-firing costs.

This analysis is intended to identify the key factors driving variation in the abatement cost associated with biomass co-firing and to provide estimates of the average abatement costs suitable for high-level planning. The results would also be useful for comparing the approximate abatement cost for co-firing technology with estimates of the social cost of carbon or estimates of abatement costs for other emissions mitigation technologies. While the analysis utilizes 2016 data reported by the US Energy Information Administration (EIA) for the MISO region at the individual power plant scale, a design-level analysis of individual power plants interested in analyzing their own abatement costs would of course rely on more detailed information than is employed here for a regional analysis.

## Materials and methods

The set of power plants included in the analysis consists of 71 utility-scale facilities in the MISO region. Power plants with significant utilization of non-coal fuel sources were excluded from the analysis. Smaller plants owned and operated by universities or private industry were also excluded. The geographic distribution and sizes of the plants are summarized in Table 1.

**Table 1** Number of included power plants and annual net generation by state (2016)

| State | Number of power plants | Median generation (MWh) | Average generation (MWh) |
|---|---|---|---|
| Illinois | 11 | 2,347,827 | 3,749,487 |
| Indiana | 14 | 1,918,654 | 3,724,339 |
| Iowa | 6 | 1,475,253 | 1,815,930 |
| Kentucky | 3 | 2,092,403 | 2,159,054 |
| Michigan | 16 | 780,677 | 2,498,416 |
| Minnesota | 4 | 1,609,641 | 2,718,759 |
| Missouri | 4 | 5,471,617 | 6,836,244 |
| North Dakota | 4 | 1,755,131 | 2,078,884 |
| Wisconsin | 9 | 3,756,559 | 3,654,989 |
| Grand total | 71 | 2,066,768 | 3,241,732 |

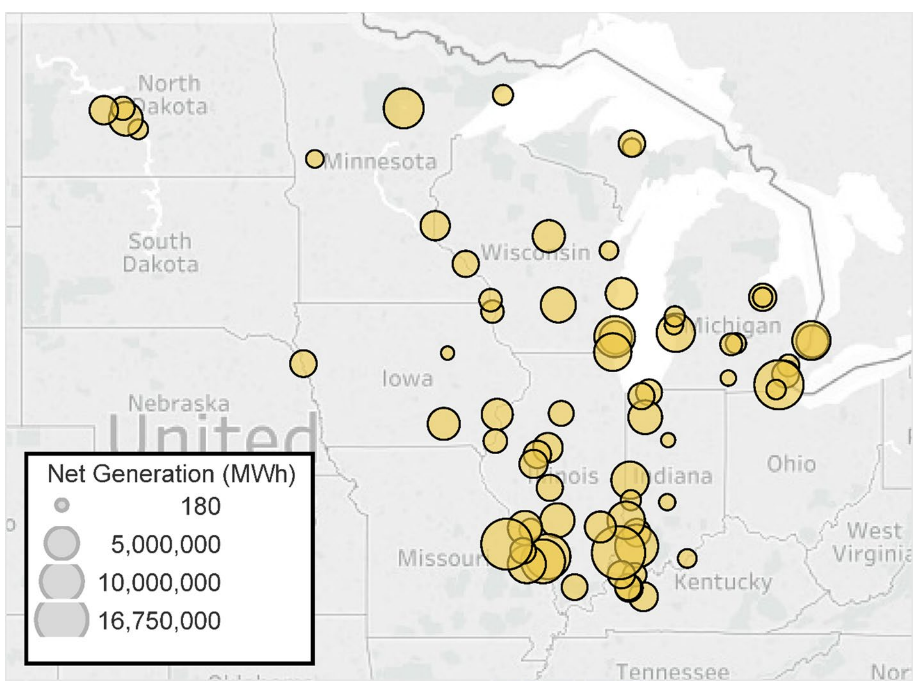


**Fig. 1** Location and annual net electricity generation of 71 coal-fired power plants in the study region (as of 2016)

## Abatement cost analysis

This analysis is restricted to the use of corn stover, as an agricultural residue, for co-firing with coal at a rate of 5%, 10%, or 20% (by energy content). Conceptually, the estimated abatement cost is equal to the difference in costs associated with co-firing biomass with the coal, divided by the difference in GHG emissions (measured in metric tons of $CO_2$-equivalents).

Calculation of the difference in costs associated with co-firing accounts for the difference in fuel costs, incremental capital and operating costs from repowering to co-fire and processing the feedstocks, and lost revenues associated with parasitic load and lost efficiency from utilization of biomass. Emissions are calculated using life cycle values. A simplified emissions model for coal incorporates emissions from combustion, fuel transport, and methane produced at the mine. For the biomass, emissions estimates come from a version of the Calculating Uncertainty in Biomass Emissions model (Curtright et al. 2011), modified to use county-level corn yield values and generate GHG emissions using the power plants as the unit of analysis. Additional details about each component of the abatement cost equation are provided in the following sections.

## Estimation of biomass utilization and coal displacement by Co-firing rate

Production data for each power plant were obtained for the year 2016 from the US EIA (US Energy Information Administration 2018). This dataset includes the quantity of fuel consumed, electricity generation (kWh), and tons of $CO_2$ emissions, broken out by plant and coal type (subbituminous, bituminous, refined, and lignite). The total annual power generation was summed over all coal types and multiplied by the assumed 5%, 10%, or 20% co-firing rate to obtain the energy content that must be replaced by the co-fired biomass. A lower heating value of 16.8 MJ per kg of corn stover was used to calculate the quantity of biomass required (International Renewable Energy Agency 2012). While baled stover is estimated to have little impact on boiler efficiency due to its low moisture content (Ortiz et al. 2011), further refinements adjust the heat rates of co-firing following Tillman (Tillman 2000).

The quantity of coal displaced by the biomass is assumed to be proportionally distributed across all coal types utilized by a plant. For example, if a plant utilizes both bituminous and subbituminous coal, the 5% co-firing scenario assumes a reduction of 5% in fuel consumption from both types. This is a simplifying assumption and may not align with actual practice if fuel costs vary substantially on an energy basis, or for other reasons.

## Estimation of biomass supply functions

Feedstock costs represent a major variable cost of biomass co-firing. This study considers the cost of obtaining corn stover, specifically the harvest and transportation costs (Langholtz et al. 2016). While the harvest location of biomass does significantly affect harvest costs, transportation costs rise with the increase in distance between harvest locations and power plants. Power plants located in areas with richer availability of local biomass pay lower transportation costs compared to power plants located in areas with low biomass density to obtain the same amount of biomass. Even in areas of high agricultural production, transportation costs constitute a large portion of total feedstock costs (Langholtz et al. 2016). Given the variation in transportation costs, the total feedstock costs to collect the same quantity of biomass are different across power plants; at a given level of feedstock cost, the supplied biomass quantities are heterogeneous across power plants. Further, heterogeneity in the electricity production at each plant means that different quantities of biomass are required to reach the same co-firing rate.

The total quantity of corn stover biomass available within a specified distance of a power plant depends on the proportion of local land being used for corn production, as well as the yield. To estimate a separate supply function for each power plant, we measure the available quantity of biomass within different radii from each plant. Specifically, we draw 80 supply circles centered on each power plant in 5 km increments for the radius (Fig. 2) and calculate the total quantity of available biomass within each circle. The feedstock cost for biomass in each circle is the total cost of harvesting and transporting biomass located at the boundary of the circle, the furthest locations with the highest transportation cost. With 80 circles, we collect 80 sets of data on biomass quantity and cost and estimate a unique biomass supply function for each power plant. We denote supply circles from smallest to largest, such that circle $r$ is defined as the circle, centered on the power plant, with a radius of $5r$ kilometers.

Corn stover is considered an ideal feedstock for co-firing (International Energy Agency, International Renewable Energy Agency 2013). Most power plants in the MISO

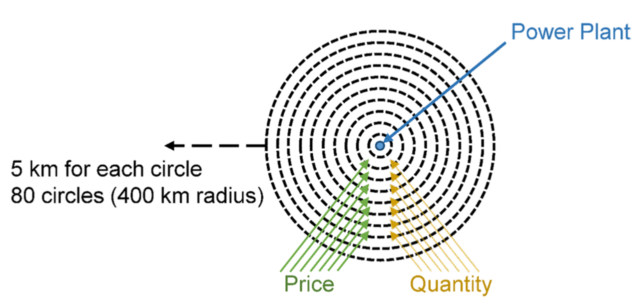


**Fig. 2** Illustrative supply circles around a power plant

region are located in the US Corn Belt and surrounded by intense production of corn and corn residues, making the region a good study area. The total available quantity of corn stover residue within each supply circle is measured using the Cropland Data Layer dataset (CDL) from the US Department of Agriculture (National Agriculture Statistics Service 2010). CDL data show the crops planted on each grid cell at a 30 m resolution. The land area of all corn-producing grid cells is aggregated to calculate the total production area of corn within each circle. The total quantity of corn stover available for co-firing within each supply circle is calculated by combining the yield data for corn and corn stover and a stover harvest rate of 33% (Thompson and Tyner 2014). Yields were calculated using a six-year moving average of harvested bushels per acre from 2010 to 2015 (National Agriculture Statistics Service 2018). In county-year combinations where yield data are unavailable, yields are imputed using a linear model based on methods from Schlenker and Roberts (Schlenker and Roberts 2009), as implemented by Haqiqi and Hertel (Haqiqi et al. 2018). The yield within each circle was assumed to equal these average yields, except in a handful of cases of urban power plants in counties with no agricultural production. In these cases, yields from adjacent counties were used instead.

The feedstock cost of corn stover includes harvest costs and transportation costs. Harvest costs are obtained from Thompson and Tyner (Thompson and Tyner 2014), which include the costs of equipment, labor, fuel, processing, storage, and replacement of nutrients removed by residue harvest. Transportation cost data are from the US Department of Energy Billion-Ton Report (2016). The data include logistics costs (which do not depend on transportation distance) and other transportation costs that are calculated based on the travel distance, laden and unladen transport costs per mile, and travel time value of money (Langholtz et al. 2016). Transport distances are calculated as the geodesic straight-line distance between a grid cell and the power plant, multiplied by an average tortuosity factor to account for roads deviating from straight lines. Specific values for the data used are reported in Table 2. The marginal cost $c_r$ of obtaining the marginal quantity $q_r$ of corn stover available within supply circle $r$ (i.e., the biomass contained in circle $r$ but not circle $r-1$) is

$$c_r = q_r\left(P + 3.107\bar{r}\tau\left(\left(D_l + D_u\right) + T/v\right)\right)$$

where $q_r$ is the dry tonnage of biomass collected from all corn-producing grid cells within circle $r$ but outside of circle $r-1$, $\bar{r}$ is the average distance of those corn-producing grid cells to the power plant, $P$ is the sum of harvest and logistics costs per dry ton, $D_l$ and $D_u$ are the laden and unladen transport costs per dry ton per mile, $\tau$ is the tortuosity factor, $T$ is the time cost of transport per dry ton per hour, and $v$ is the average velocity of transport in miles per hour. The constant factor converts the average distance $\bar{r}$ from kilometers to miles (5 km = 3.107 miles).

Midwestern states in the MISO region are major corn producers. Availability of corn stover is high, and we assume that stover is treated as a residue not used for other purposes such as production of cellulosic ethanol. However, stover plays a role in soil replenishment, so the analysis assumes a cost for nutrient replacement after its removal (as noted in the previous paragraph). Under this assumption, the collection radius required for each plant and co-firing rate very rarely exceeds 100 km, as shown in Fig. 3. This distance is well below the radius beyond which densification for transport (i.e., pelletization) becomes economically advantageous (Ortiz et al. 2011). As such, the calculations of life cycle GHG emissions, processing costs, and transport costs assume the corn stover is simply baled.

This analysis focuses on the variability in abatement costs associated with each power plant if they were to

**Table 2** Parameters used to calculate quantities and costs of corn stover

| Parameter | Value | References |
|---|---|---|
| Yield of corn | Varies spatially | USDA NASS 2010–2015; Haqiqi and Hertel (2018) |
| Grain-stover mass ratio | 1:1 | Perlack and Turhollow (2003); Langholtz and Stokes (2016) |
| Harvest rate | 33% | Thompson and Tyner (2014) |
| Harvest costs | \$42.12/dry ton[1] | Thompson and Tyner (2014) |
| Logistics cost (transportation) | \$28.80/dry ton | Langholtz and Stokes (2016) |
| Tortuosity factor | 1.2 | Quear (2008); Tyner et al. (2010) |
| Distance cost, loaded | \$0.038/dry ton/mile | Langholtz and Stokes (2016) |
| Distance cost, unloaded | \$0.027/dry ton/mile | Langholtz and Stokes (2016) |
| Time cost (transportation) | \$3.90/dry ton/hour | Langholtz and Stokes (2016) |
| Average transportation speed | 45 miles/hour | Assumed |

[1] \$46.43/Mg in the literature, converted with 1 Mg = 1.1023 US ton

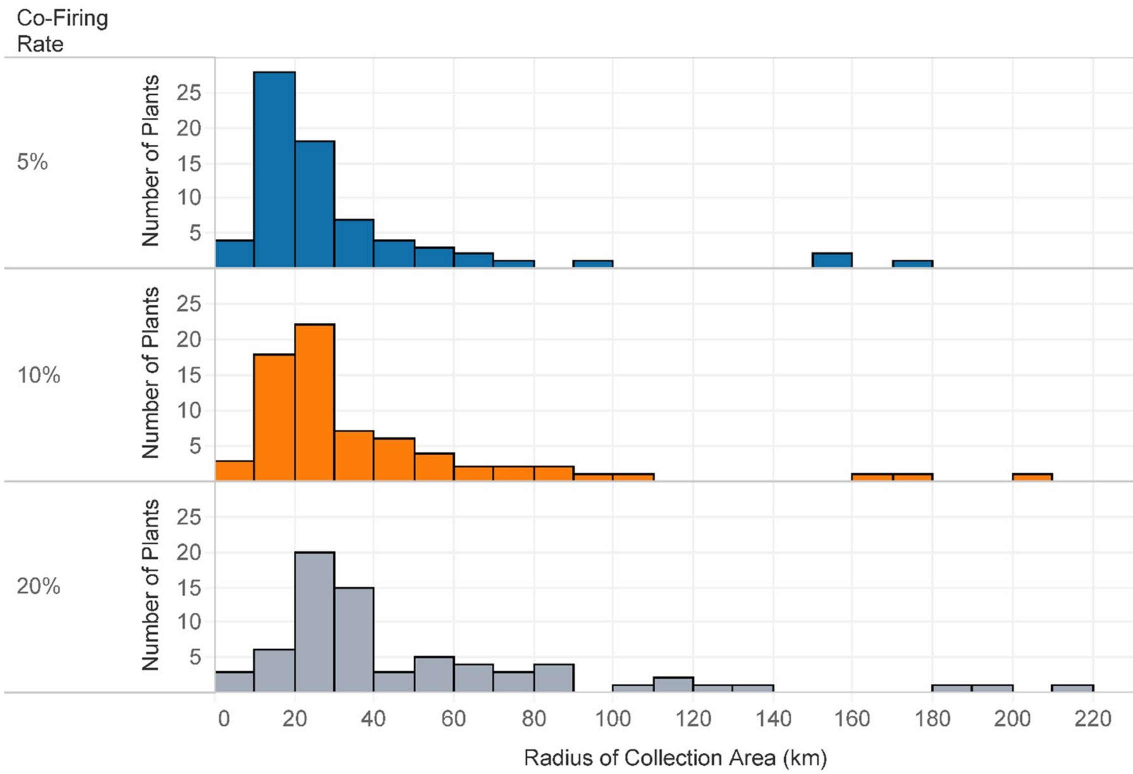


**Fig. 3** Frequency distribution of collection radius size by co-firing rate

choose to co-fire biomass, independent of other plants' actions. Thus, geospatial proximity between some of the plants is ignored; if multiple power plants acted simultaneously, potential overlap in collection areas could impact resource availability and prices.

The calculated feedstock cost is the sum of harvest and transportation costs for the biomass harvested on the boundary of each circle, representing the highest cost within the circle. It can also be understood as the price that a power plant needs to pay to purchase the last unit of biomass available within a given supply circle. This approach yields 80 values defining the relationship between the quantity and price, specific to each power plant, associated with sourcing biomass from within a radius of 0 to 400 km (in practice, all plants are able to satisfy their biomass tonnage requirements at distances well less than 400 km). Because the supply circles are concentric, the marginal tonnage available at the price associated with each supply circle is calculated. The total costs to obtain the biomass required for a given plant and co-firing rate are calculated by summing over the marginal costs associated with each supply circle until the required tonnage is met. Equivalently, we multiply the total tonnage required by the average supply cost over each supply circle utilized; as such, rents do not accrue to infra-marginal producers.

## Estimation of coal costs

As noted previously, the analysis assumes that the tonnage of coal displaced by biomass co-firing is distributed proportionally across all fuel types, in accordance with the specified co-firing rate. These quantities are then multiplied by assumed costs for each coal type (as summarized in Table 3). The costs from the table are adjusted for transportation costs, assuming that transportation represents approximately 25% of the total delivered price (US Energy Information Administration 2015).

## Estimation of incremental costs

Co-firing biomass with coal can require additional capital expenditures for biomass-specific equipment. It also incurs incremental operating expenses related to the storage,

**Table 3** Assumed plant-gate costs of coal by type

| Coal type | Cost ($ per ton) | References |
|---|---|---|
| Bituminous | $19.46 | US EIA (2015) |
| Subbituminous | $68.59 | US EIA (2015) |
| Refined | $67.95 | KPMG (2017) |
| Lignite | $29.74 | US EIA (2015) |

handling, and processing of biomass before firing. Finally, parasitic load associated with processing and handling, and the minor decrease in efficiency associated with use of corn stover both represent opportunity costs in the form of lost revenue.

Costs for each of these categories are adopted from the baled herbaceous feedstock scenario in Ortiz, et al. (Ortiz et al. 2011), inflated to the year 2018. Values for the 20% co-firing rate are extrapolated from the 2%, 5%, and 10% scenarios presented in that report. These are summarized in Table 4; all values are given in terms of dollars per kWh of production.

### Estimation of life cycle coal emissions

GHG emissions associated with the coal-fired electricity life cycle are dominated by combustion emissions of carbon dioxide (Jaramillo et al. 2007; Whitaker et al. 2012). Emissions from combustion in 2016 are reported by the US EIA, specific to each plant and coal type (US Energy Information Administration 2018). As noted in Sect. 2.2, the specified co-firing rate scenario determines the quantity of each coal type displaced by biomass. For each plant, the reduction in GHG emissions from coal combustion is therefore calculated by reducing the EIA-reported emissions for each coal type by the same proportion as the reduction in fuel tonnage. This approach accounts for the fact that different power plants have different emissions factors.

As concluded by Whitaker et al. (2012), transportation emissions are assumed to be 3% of combustion emissions on average. The vast majority of GHG emissions from coal production are attributable to coal mine methane emissions; this analysis assumes the median value of 63 g $CO_2$–eq/kWh from Whitaker, et al. (2012). These three categories—combustion, transportation, and production—collectively represent over 99% of the life cycle emissions for coal-based electricity generation.

### Estimation of life cycle biomass emissions

GHG emissions associated with the co-fired corn stover are calculated using the Calculating Uncertainty in Biomass Emissions (CUBE) model, a life cycle inventory tool developed by analysts at RAND Corporation for the US Department of Energy's National Energy Technology Laboratory (Curtright et al. 2011). CUBE estimates the life cycle GHG emissions associated with production of seven different biomass feedstocks over a wide range of production scenarios driving differences in emissions, including production on different prior land use types, over different lengths of time, and in different geographic locations (Johnson et al. 2013). Full details on the methods, data sources used, and validation for estimating life cycle biomass emissions are available in Curtright, et al. (Curtright et al. 2011). The original version of the model calculated "farm-to-gate" emissions agnostic of the end use of the biomass (i.e., electrification or conversion to liquid fuels for transportation). This analysis adds combustion emissions for the biomass based on the carbon content of corn stover (Kumar et al. 2008). The CUBE model has also been modified to utilize county-specific yields and to report estimates of emissions associated with the tonnage needed for each combination of power plant and co-firing rate.

The system boundary of CUBE excludes indirect land use change. This exclusion is reasonable when considering emissions attributable to corn stover, an agricultural residue, for individual power plants acting in isolation (Taheripour and Tyner 2013). The system boundary does include GHG sources such as $N_2O$ release from volatilization of fertilizer; direct emissions from agrochemical production and application, cultivation, transportation, and processing; and other minor sources such as emissions due to storage losses.

Assumptions about the production scenario within CUBE are harmonized with the supply function analysis where required (e.g., harvest ratio, yield). Because resource availability was derived from actual corn production acreages in the supply curve analysis, it is assumed that all production occurs on existing row crop land when assessing GHG emissions from soil and root carbon storage. This includes carbon from emissions associated with nutrient replacement (Anderson-Teixeira et al. 2009). If future renewable energy policies strongly incentivize land use change for production of biomass for electrification, this assumption should be revisited. Other management practices impacting GHG emissions, such as passive field drying and low-loss storage methods (e.g., covered bales), are taken from the default production scenarios prescribed by the CUBE model.

**Table 4** Incremental costs associated with co-firing biomass ($ per kWh). Source: Ortiz et al. (2011)

| Co-Firing rate | Capital costs | Operating costs (Biomass) | Operating costs (Coal) | Lost revenue | Total marginal cost |
|---|---|---|---|---|---|
| 5% | $ 0.014 | $ 0.089 | $ 0.006 | $ 0.004 | $ 0.102 |
| 10% | $ 0.014 | $ 0.044 | $ 0.006 | $ 0.007 | $ 0.059 |
| 20% | $ 0.014 | $ 0.022 | $ 0.006 | $ 0.018 | $ 0.048 |

## Results and discussion

Figure 3 presents an intermediate result, the collection radius required to source the necessary quantity of biomass to achieve a 5%, 10%, or 20% co-firing rate. Even under the 20% co-firing rate scenario, the clear majority of power plants are able to source sufficient biomass from within a 50 km radius. This may be an artifact of using the MISO region as the study domain, which overlaps heavily with major corn-producing states. In other parts of the world where corn is not the dominant crop (or in the case of analyzing other biomass feedstocks), a larger collection radius may be required.

**Table 5** Summary of abatement costs by co-firing rate

| Co-Firing rate | Median | Average | Standard Deviation |
|---|---|---|---|
| 5% | \$ 119.94 | \$ 123.71 | \$ 31.63 |
| 10% | \$ 56.85 | \$ 64.43 | \$ 24.73 |
| 20% | \$ 41.29 | \$ 49.20 | \$ 23.37 |

The estimated abatement costs (\$ per metric ton $CO_2$–eq) are provided in Table 5 (median, average, and standard deviation), as summarized over all 71 power plants in the data set.

Abatement costs decrease substantially for higher co-firing rates, due to incremental capital costs that decline on a per-kWh basis when co-firing greater quantities of biomass. The full distribution of abatement costs over the 71 power plants is shown in Fig. 4, with the same values mapped geospatially along with the size of the plant in Fig. 5.

As noted in the Introduction section, many different factors could lead to variation in the abatement costs by power plant, such as power plant characteristics (e.g., average fuel costs, production capacity), or geospatial variation in feedstock yields or corn production density. To examine this, further analysis of the abatement costs as a function of explanatory variables such as these is necessary.

Figure 6 shows the estimated abatement cost for each power plant at co-firing rates of 5%, 10%, and 20%, as a function of the local corn yield. As suggested visually, the relationship between corn yield and the cost of reducing GHG emissions through co-firing is insignificant when controlling for the co-firing rate (Pearson correlation values of

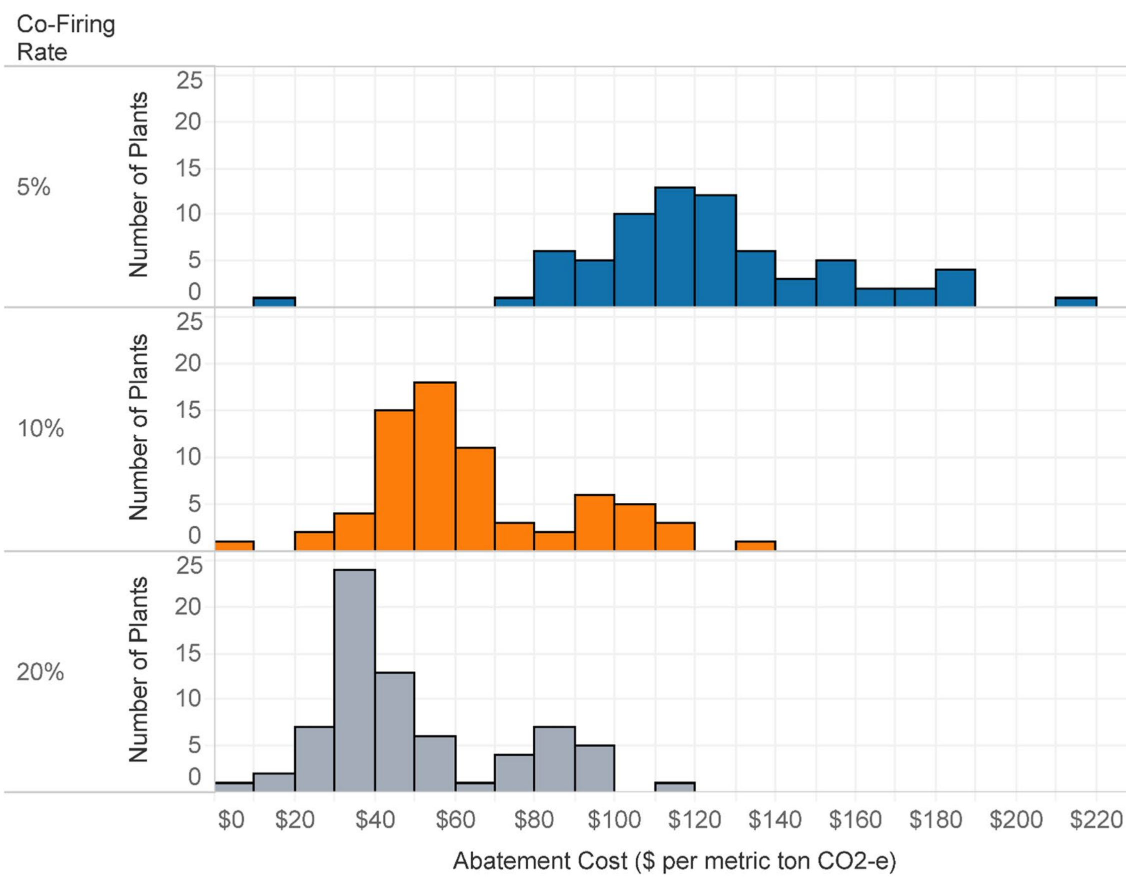


**Fig. 4** Histogram of abatement costs by co-firing rate

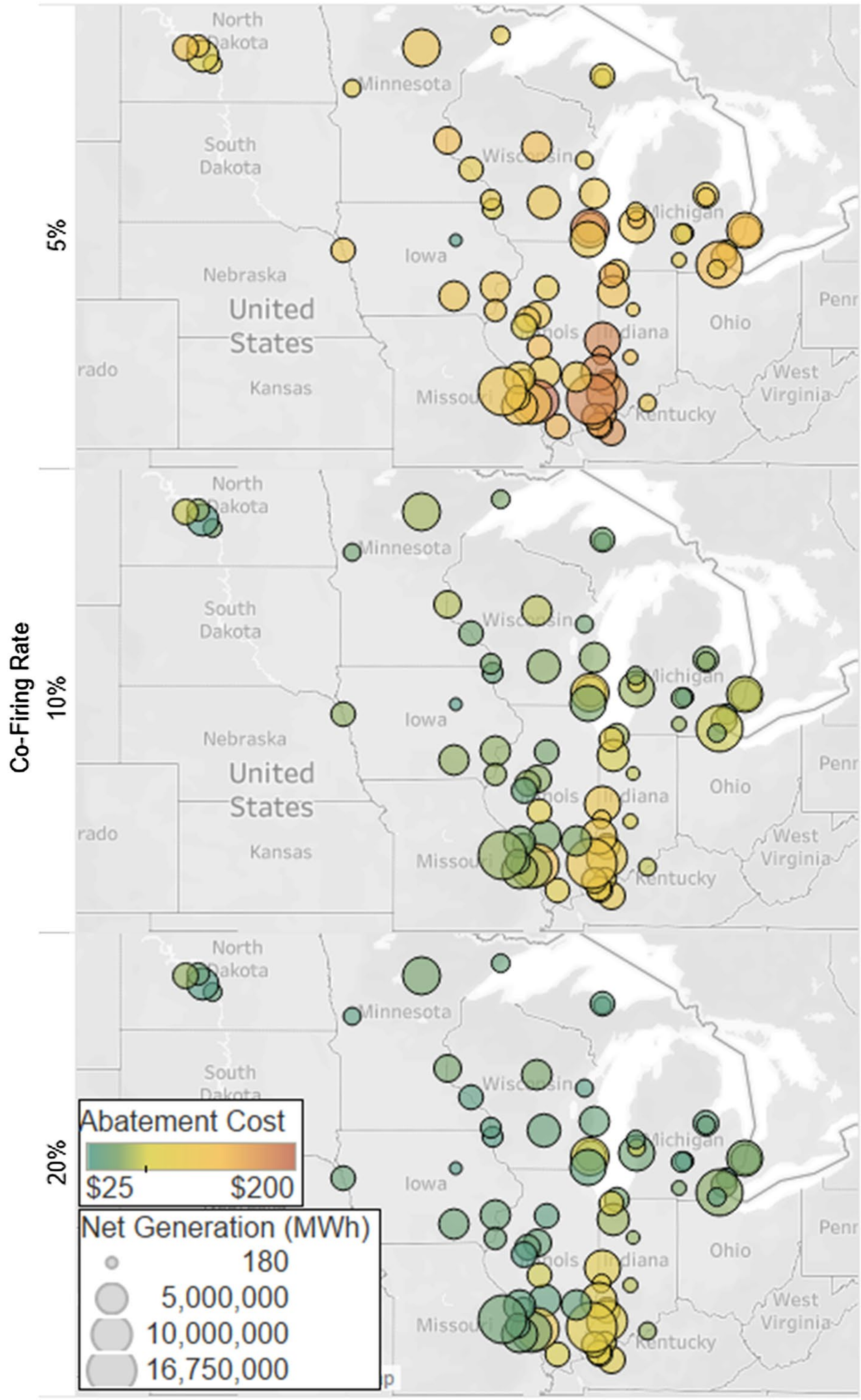


**Fig. 5** Abatement costs ($ per metric ton $CO_2$-equivalent) by power plant and co-firing rate. The size of each dot indicates the net generation (MWh) of the plant in 2016

− 0.11, − 0.08, and − 0.07 at co-firing rates of 5%, 10%, and 20%, respectively).

Similarly, abatement costs appear to have little correlation with the size of the required collection radius (after controlling for the chosen co-firing rate). Perhaps this is not surprising, as the collection radius is partially determined by the local corn yield and the co-firing rate (in addition to the production density of corn and the size of the power plant). Further refinement of the analysis could develop a better measure of local corn production density to test whether it can explain more of the variance in abatement costs. However, this may not be the case,

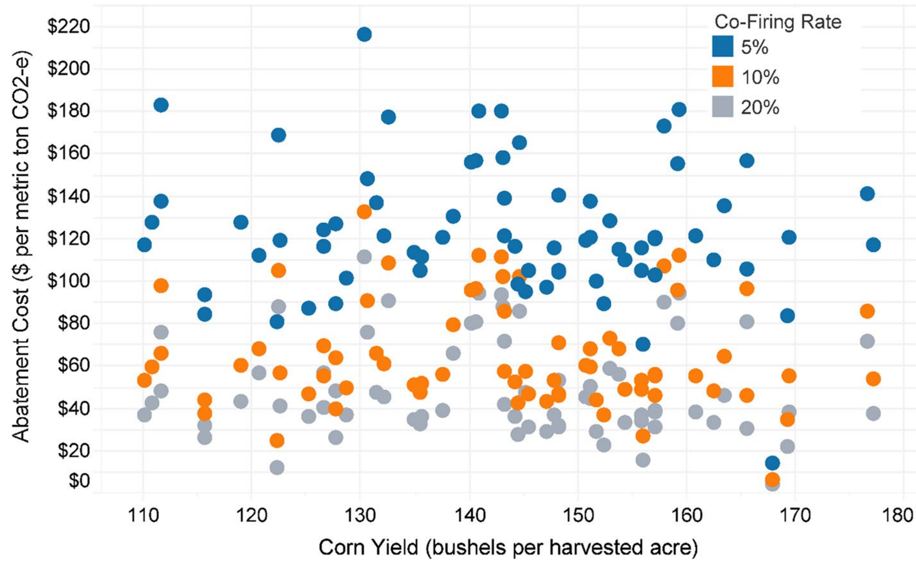


**Fig. 6** Abatement cost by co-firing rate, as a function of local corn yield

as production density is likely to be somewhat correlated with local yields.

Figure 7 examines the relationship between the size of the power plant and the estimated abatement costs. The trend lines for each co-firing rate are fit using a cubic polynomial; they all have F statistics with p values less than 0.0001.

The key findings from Fig. 7 are that abatement costs are generally an increasing function of the power plant size. This is intuitive, given that larger plants would require larger quantities of biomass for a specified co-firing rate, resulting in a larger collection area and transportation costs associated with feedstock sourcing. Visually, it appears that there may be a slight decline in abatement costs for the very largest power plants; this seems plausible if greater electricity production is correlated with marginally more expensive average fuel costs.

Figure 8 portrays the relationship between abatement cost, co-firing rate, and the unit cost of coal fuel ($ per kWh, where variation stems from the plants' fuel mixes among the four coal types reported by EIA). The trend lines in Fig. 8 are also fit using cubic polynomials. Again, all three lines have F statistics with $p$ values less than 0.0001, indicating a statistically significant relationship between the abatement cost and the unit cost of coal fuel. Abatement costs should clearly be a decreasing function of average unit fuel costs, and this is indeed observed.

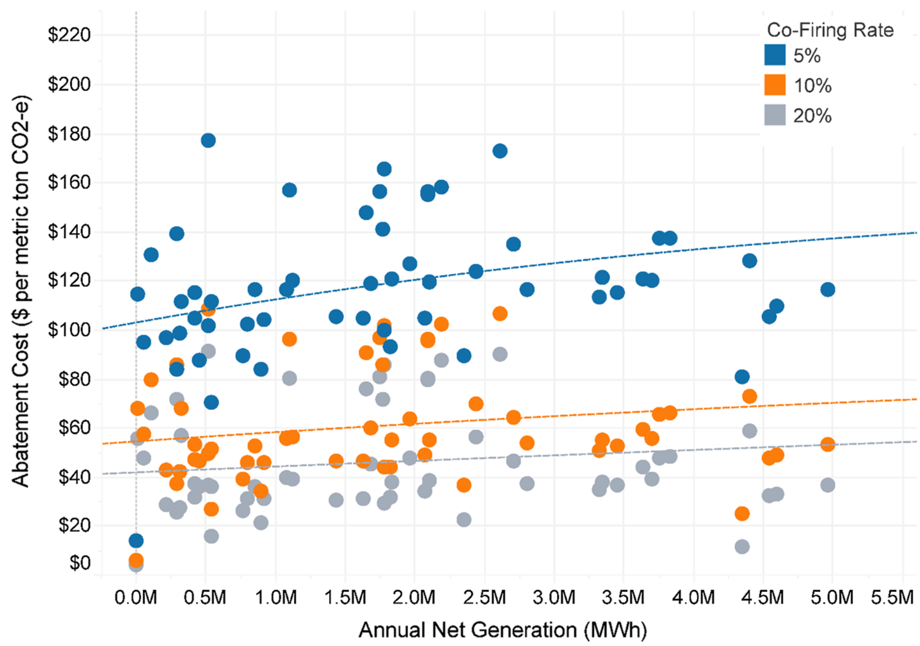


**Fig. 7** Abatement cost by co-firing rate, as a function of electricity generation

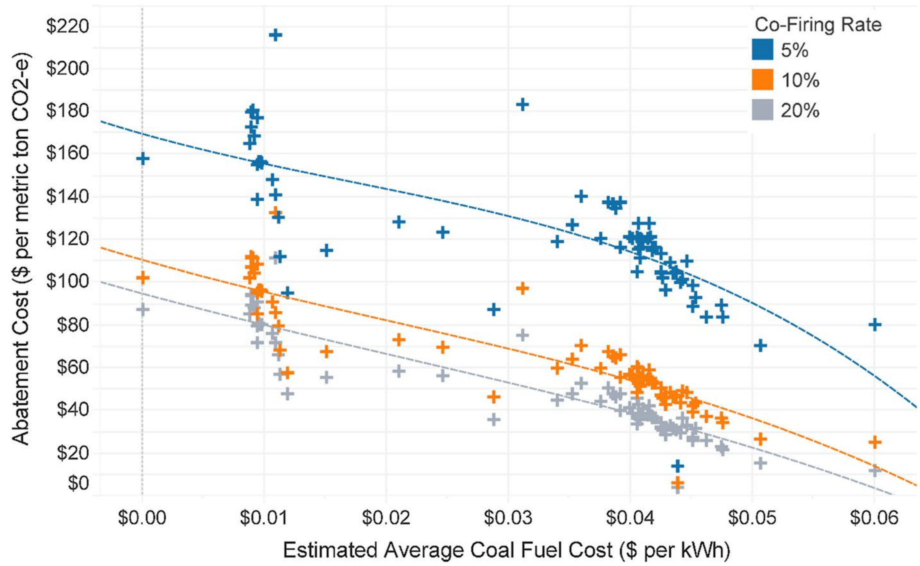


**Fig. 8** Abatement cost by co-firing rate, as a function of unit coal fuel costs

**Table 6** Regression statistics from a linear model of abatement costs

| | Estimate | SE | *p* value |
|---|---|---|---|
| *5% Co-fire* | | | |
| (Intercept) | 1.69E+02 | 2.34E+01 | 6.48E-10 |
| Generation (kWh) | 3.49E-09 | 6.65E-10 | 1.76E-06 |
| Coal unit cost ($/kWh) | − 1.44E+03 | 1.55E+02 | 1.27E-13 |
| Corn yield (bu/acre) | − 6.84E-02 | 1.52E-01 | 6.53E-01 |
| Collection radius (km) | − 8.07E-03 | 8.33E-02 | 9.23E-01 |
| *10% Co-fire* | | | |
| (Intercept) | 1.05E+02 | 1.24E+01 | 4.09E-12 |
| Generation (kWh) | 1.90E-09 | 3.55E-10 | 1.16E-06 |
| Coal unit cost ($/kWh) | − 1.42E+03 | 8.25E+01 | <2.00E-16 |
| Corn yield (bu/acre) | − 1.64E-02 | 8.10E-02 | 8.40E-01 |
| Collection radius (km) | 2.78E-02 | 3.90E-02 | 4.78E-01 |
| *20% Co-fire* | | | |
| (Intercept) | 8.81E+01 | 9.91E+00 | 6.85E-13 |
| Generation (kWh) | 1.48E-09 | 2.83E-10 | 1.89E-06 |
| Coal unit cost ($/kWh) | − 1.42E+03 | 6.49E+01 | <2.00E-16 |
| Corn yield (bu/acre) | − 3.80E-04 | 6.45E-02 | 9.95E-01 |
| Collection radius (km) | 3.94E-02 | 2.76E-02 | 1.59E-01 |

Putting the various covariates together in a simple linear model, instead of plotting them separately from one another, yields similar findings. Table 6 presents the regression coefficients, standard errors, and *p* values associated with net electricity generation, unit coal costs, corn yields, and the size of the collection radius. For all co-firing rates, the electricity generation and coal unit costs are both highly statistically significant; conversely, the corn yield and collection radius are not statistically significant at the 0.05 level for any co-firing rate.

The marginal effects indicate that, *ceteris paribus*, a 1-cent increase in the average cost per kWh of coal fuel is associated with a decrease in the abatement cost of $14.38 per ton of $CO_2$-e at a 5% co-firing rate, $14.19 at 10%, and $14.16 at 20%. Likewise, *ceteris paribus*, a 1-million MWh increase in annual generation is associated with a $3.49 increase in the abatement cost at a 5% co-firing rate, $1.90 at 10%, and $1.48 at 20%.

## Conclusion

This study examines the abatement costs associated with co-firing corn stover at existing coal-fired power plants in Midwestern states of the MISO electricity transmission region. Key findings include considerable variability in the estimated costs of using corn stover to reduce GHG emissions. The co-firing rate, average cost of coal, and size of the power plant are the key determinants of the abatement costs, which do not appear to be particularly sensitive to variability in corn yields or the size of the collection area. While these results are specific to co-firing corn stover with coal in the American Midwest, the conceptual model presented here is easily transferrable to other regions of the world or other biomass feedstock, provided that data are available. One should consider, however, whether other potential feedstocks should be treated as a residue or whether harvest for electrification would generate appreciable indirect land use change.

This work advances knowledge about real-world abatement costs for the electric power sector by incorporating spatial heterogeneity in resource availability and existing plant characteristics into integrated models of co-firing costs and life cycle GHG emissions. Future study is needed to explore additional determinants of variability and validity of the findings to other regions and feedstocks. For example, sensitivity of the abatement cost to the feedstock yield of corn may be greater in other regions outside of the American Corn Belt due to greater variability in yield and production density. Further analysis could also be done regarding estimates of how the co-firing scenarios described here could contribute to meeting policy targets set by state renewable portfolio standards, how competition for biomass resources would impact feedstock costs, and whether renewable energy credits would be effective incentives for co-firing adoption in existing coal plants.

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**Data availability** Data underpinning the analysis come from publicly available sources (e.g., USDA Cropland Data Layer, US EIA). Data related to the life cycle inventory analysis come from a wide range of journal articles and technical reports, as documented in Wilson et al. (2012).

**Code availability** Scripts used to generate the analysis are available upon request.

## Declarations

**Conflict of interest** The authors have no conflicts of interest to declare that are relevant to the content of this article.

**Ethical approval** This article does not contain any studies with human participants or animals performed by any of the authors.

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