Demand for biomass to meet renewable energy targets in the United States: implications for land use

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Abstract

Renewable energy policies in the electricity and transportation sectors in the United States are expected to create demand for biomass and food crops (corn) that could divert land from food crop production. We develop a dynamic, open-economy, price-endogenous multi-market model of the US agricultural, electricity and transportation sectors to endogenously determine the quantity and mix of bioenergy likely to be required to meet the state Renewable Portfolio Standards (RPSs) and the federal Renewable Fuel Standard (RFS) if implemented independently or jointly (RFS & RPS) over the 2007–2030 period and their implications for the extent and spatial pattern of diversion of land from other uses for biomass feedstock production. We find that the demand for biomass ranges from 100 million metric tons (MMT) under the RPS alone to 310 MMT under the RFS & RPS; 70% of the biomass in the latter case can be met by crop and forest residues, while the rest can be met by devoting 3% of cropland to energy crop production with 80% of this being marginal land. Our findings show significant potential to meet current renewable energy goals by expanding high-yielding energy crop production on marginal land and using residues without conflicting with food crop production.

Keywords: bioelectricity, biotuels, dynamic optimization, partial-equilibrium model, Renewable Fuel Standard, Renewable Portfolio Standard, spatial analysis

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Introduction

Growing interest in renewable energy for the electricity and the transportation sectors has led to state-level Renewable Portfolio Standards (RPSs) and the federal Renewable Fuel Standard (RFS) that mandate a share/quantity of demand being met by renewable energy sources. Bioenergy is expected to play a significant role in achieving these policies as it will be used to produce cellulosic biofuels and can also be used to generate bioelectricity (EIA, 2010a). Twenty-nine states have implemented RPSs that range from 10% to 40% of electricity being produced using renewable sources by 2030 (DSIRE, 2011). The RFS sets a target for 136 billion liters of biofuels of which at least 61 billion liters are to be from cellulosic biomass and at most 57 billion gallons from corn ethanol.

Biomass can be produced from a variety of different sources, including dedicated energy crops like miscanthus and switchgrass, woody biomass such as poplar, crop residues from corn and wheat and forest biomass. Biomass can be used to produce bioenergy in several ways. It can generate bioelectricity by co-firing it with coal in a coal-based power plant or combusting it in a dedicated bioelectricity plant. Additionally, it can also generate bioelectricity as a coproduct during the process of conversion to cellulosic biofuels. The potential and cost of producing various feedstocks are likely to vary spatially due to differences in growing conditions; additionally, demand for bioelectricity may also vary spatially due to differences in the stringency of the RPSs across regions and the location of existing coal-based electricity plants that can potentially co-fire biomass with coal.

We examine the demand for biomass likely to be generated and the land required to meet this demand by the state RPSs and RFS policies over the 2007–2030 time period. We also examine the biomass price at which it will be feasible to do so and the implications of biomass production for food crop production as land is likely to be diverted from food to fuel production. Lastly, we examine the spatial pattern of biomass production under these policies. We compare the effects of implementing the RPSs and the RFS independently with those of implementing them jointly to analyze the effects of competing demands for biomass on biomass price, feedstock mix and the spatial pattern of feedstock production.

We undertake this analysis by extending a dynamic, price-endogenous, open-economy model of the electricity, transportation and agricultural sectors in the United States, the Biofuel and Environmental Policy Analysis...
Model (BEPAM-E) (Oliver & Khanna, 2017). The model endogenously determines the mix of renewable energy from different sources to meet the RFSs, the mix of feedstocks to produce bioelectricity and biofuels and the spatial location of their production. It also endogenously determines the allocation of available cropland and marginal land (in crop/pasture/fallow rotations) to be allocated to different uses (food, feed and fuel) and the prices and quantities of agricultural commodities, fuel, electricity and biomass. This paper extends the BEPAM used previously to analyze the effects of biofuel policies on the transportation sector (Huang et al., 2013; Chen et al., 2014) by including the US electricity sector and related fossil fuel sectors (coal and natural gas) that provide inputs to the electricity sector. The extended BEPAM-E (BEPAM with the electricity sector) incorporates the existing fossil and renewable electricity generating capacity in the United States as well as the potential for expansion in natural gas, wind and bioelectricity generation (Oliver & Khanna, 2017).

Early studies have examined the potential of co-firing at national levels (McCarl et al., 2000) and regional levels: in Illinois (Khanna et al., 2008; LaTourrette et al., 2011) and Indiana (Brechbill et al., 2011). Dumortier (2013) examines the supply of biomass from crop and forest residues and switchgrass at exogenously set biomass price and the availability of biomass for cellulosic biofuels assuming a binding constraint on demand for co-firing imposed by existing coal-based electricity plants. He shows that there would be shortfalls in biomass availability for cellulosic biofuel production in much of the Southeast. In contrast, our analysis endogenously determines the extent to which there will be an incentive to co-fire or produce bioelectricity in a biopower plant. Other studies have examined the implications of using a single feedstock, forest biomass, in the Southeast (Abt et al., 2012) and the United States (Ince et al., 2011) for producing bioelectricity for feedstock price.

A few studies have used the national scale Forest and Agricultural Sector Optimization Model (FASOM) to predict the mix of forest and agricultural biomass feedstock to meet exogenously given demand for bioelectricity (Latta et al., 2013; White et al., 2013). Palmer & Burtraw (2005) analyze the implications of a hypothetical federal RPS for the price of electricity assuming an exogenously given supply curve of biomass. Other studies have examined the feedstock price needed to induce the biomass supply needed to meet a 21-billion gallon cellulosic biofuel target (Langholtz et al., 2014) and to meet exogenously given targets for both biofuel and bio-power targets (Langholtz et al., 2012). Most recently, Sands et al. (2017) examine the land-use requirements for supplying about 250 million megawatt hours (M MWh) of bioelectricity in 2030 using switchgrass as the only feedstock. They find that this will require 10–12 million hectares of land; two-thirds of this would be obtained from converting cropland to switchgrass production, and the rest would be obtained from marginal land and forest land.

We extend this literature by considering a broad range of feedstocks, including, crop and forest residues and energy crops. We endogenously determine the share of bioelectricity in meeting the RPS, and the mix, price, and location of biomass feedstocks to meet it.

There is a large literature examining the effect of the RFS on land use and food and fuel prices (Beach et al., 2012; Chen et al., 2014; Hudiburg et al., 2016). These studies have assumed the RFS is implemented in isolation and not considered the implications of a concurrently implemented RFS with spatially varying targets for renewable electricity. We analyze the synergies and trade-offs in meeting goals of one renewable energy policy in the presence of the other and its spatially explicit implications for land use. We also extend previous work in Oliver & Khanna (2017) that examines the cost-effectiveness of GHG mitigation by jointly implemented RPSs and the RFS relative to a carbon tax policy. Here we compare biomass demand and land-use outcomes under the RPSs to those under the RFS and in the case with the two policies implemented concurrently.

Materials and methods

Model

Biofuel and Environmental Policy Analysis Model (BEPAM-E) is a nonlinear, dynamic, multi-sector, price-endogenous, open-economy, partial-equilibrium, mathematical programming model that simulates US agricultural, transportation fuel and electric power sectors including international trade with the rest of the world (ROW) (for a detailed description of model equations and data; see Oliver & Khanna, 2017). Market equilibrium is found by maximizing the sum of consumers’ and producers’ surpluses in the agricultural, transportation fuel and electric power sectors subject to various material balance constraints and technological constraints in a dynamic framework over the 2007–2030 period. BEPAM-E considers production of crop and biofuel feedstocks at the level of a Crop Reporting District (CRD) where crop production costs, yields and resource endowments are specified for each CRD and each crop. The 306 CRDs in the 48 contiguous US states are used as spatial units to model electricity generation from existing power plants by fuel type, while generation from new electricity capacity is considered at the level of twenty Electricity Market Regions (EMRs). The model endogenously determines the agriculture and transportation sector variables of food consumption, gasoline, diesel and biofuel consumption, imports of gasoline and sugarcane ethanol, mix of biofuels and regional land allocation among different food, feed and fuel crops and

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livestock activities over a given time horizon. It also endogenously determines electricity sector variables such as generation by energy type (coal, natural gas, oil, wind, co-fired biomass, dedicated biomass and coproduct), regional electricity consumption, inter-regional electricity transmission, bioelectricity feedstock transportation and GHG emissions.

A dynamic model allows us to distinguish among feedstocks that differ in their upfront costs and life span over which they yield returns. The model is run on an annual time scale using a rolling horizon approach in which decision makers are assumed to make land allocation plans for the next 10 years taking current prices, demand conditions, land availability in different categories and costs of technology as given and then to update their expectations about these variables every year. The model is solved iteratively; after solving each 10-year market equilibrium problem, we take the first-year solution values as ‘realised’, move the horizon 1 year forward and solve the updated model again. This structure enables us to incorporate technological change over time that lowers the costs of renewable technologies due to learning by doing across horizons (see Oliver & Khanna, 2017).

Electricity sector. Each of the twenty EMRs in the electricity sector has its own demand for electricity and potential to trade across geographically adjacent regions subject to constraints on transmission capacity. These EMRs are defined similarly to those in the EIA’s National Energy Modelling System (NEMS) (EIA, 2011a), and for the most part an EMR consists of one or more states. A few EMRs in NEMS did not align with state boundaries or had regions smaller than a state. We redefined these to follow state boundaries to be able to link them consistently with the agricultural production regions defined at the CRD level. We allow for inter-regional electricity transmission between adjacent EMRs subject to transmission capacity constraints based on historically observed levels and a loss during transmission and distribution (EIA, 2011b).

Electricity demand functions are specified for each EMR as an aggregation of state-level, sector-specific (residential, commercial and industrial) demand functions. The annual demand for electricity is met by existing installed electricity generation capacity as well as expansion of generation capacity using natural gas, wind or biomass sources; the extent to which each type of source is used is endogenously determined based on relative costs. Fuel inputs for electricity generation include coal, natural gas, and fuel oil and biomass feedstocks from the agricultural and forest sectors.

Existing power plants are aggregated to the CRD level by energy type, which consists of coal, natural gas, oil, hydroelectric, nuclear, geothermal, municipal solid waste, solar, biomass, wind, and other. This power plant capacity is regionally heterogeneous in the energy type, nameplate capacity, and conversion efficiency. The decision can also be made to expand generation capacity that uses natural gas, wind, or biomass energy, while expansion from other sources is specified exogenously according to projections from the AEO (EIA, 2010a). Expansion of electricity generation capacity with each of these sources depends on the endogenously determined fuel cost per kilowatt hour (kWh), the conversion efficiency, and the leveled cost of generation which consists of the annualized fixed cost and variable O&M costs per kWh. An exception is the cost (supply) of wind electricity generation in each EMR, which is modeled by an upward sloping function following Paul et al. (2009). These functions represent the marginal cost of generation from new wind turbine capacity that increases with the amount of wind-based electricity generated in a region as the availability of wind resources in the EMR diminishes.

Bioelectricity generation can be expanded along three pathways: co-firing at a coal power plant, firing at a new dedicated biomass power plant, and as a coproduct of cellulosic ethanol refining. Co-fired biomass is assumed to be converted using the same heat rate as the particular coal power plant, while generation from bio-power and coproduct sources is based on an assumed heat rate from the literature (Qin et al., 2006; Humbird et al., 2011). The heat rate determines the amount of feedstock required to generate a kWh of electricity and thus affects the relative price of bioelectricity; we examine the sensitivity of results to these assumptions. We assume a 10% limit on the mixture of biomass to coal, but also examine a more relaxed co-firing limit of 20% which falls within the range examined in other studies (Qin et al., 2006; Dumortier, 2013). We incorporate the cost of transporting biomass from a CRD producing it to other CRDs for co-firing with existing coal-based capacity in determining the location of biomass production for co-firing. As a result, the endogenous marginal cost of generation from co-firing is a function of the delivered price of biomass feedstock, the conversion efficiency of the coal power plant and biomass processing costs. The endogenous price of generation from a dedicated bio-power plant is similarly a function of the delivered price of biomass feedstock, the heat rate of the bio-power plant, the biomass processing cost, and the levelized cost of capacity net of fuel (for further details, see Oliver & Khanna, 2017). Transmission of electricity generated in an EMR to end-use consumers in other EMRs is subject to transmission capacity constraints, a transmission cost and some loss of electricity during transmission.

Agricultural sector. The agricultural sector includes fifteen conventional crops, eight livestock products, two perennial bioenergy crops, crop residues from the production of corn and wheat, forest residues, and coproducts from the production of corn ethanol and soybean oil (for further details, see Chen et al., 2014). In the crop and livestock markets, primary crop and livestock commodities are consumed either domestically or traded with the ROW (exported or imported). Primary crop commodities can also be processed or directly fed to various animal categories. Domestic and export demands and import supplies are incorporated by assuming linear price-responsive demand or supply functions. The commodity demand functions and export demand functions for tradable row crops and processed commodities are shifted upward over time at exogenously specified rates.

The simulation model incorporates CRD-specific data on costs of producing crops, livestock, biofuel feedstocks, yields of conventional and bioenergy crops, and land availability. Crops can be produced using alternative tillage, rotation, and irrigation practices. Yields and costs of production of crop residues and dedicated energy crops also differ across regions. We estimate the rotation-, tillage- and irrigation-specific costs of
production in 2007 prices for each of the row crops and energy crops at a county level which are then aggregated to the CRD level for computational ease. Row crop yields increase over time as in Chen et al. (2014).

Biomass can be obtained from four different types of feedstocks: crop residues, energy crops, forest residues and pulpwood. The energy crops considered here are miscanthus and switchgrass, which can be produced on available cropland or cropland pasture. Production of dedicated energy crops is limited to the rain-fed regions which include the Plains, Midwest, South, and Atlantic, while conventional crops can be grown in the Western region as well. The supply of forest residues and pulpwood is modeled at the CRD level using available quantities obtained from the USDOE’s Billion-Ton study on the annual quantity of county-level supplies at various biomass prices (Perlack & Stokes, 2011).

Five land types are included in the agricultural sector for each CRD: cropland, idle cropland, cropland pasture, pasture land and forestland pasture. As the demand for agricultural land increases, marginal lands (not currently utilized) can be converted to cropland, with the extent of conversion determined by variations in crop prices over time; agricultural land supply is, therefore, determined endogenously. We assume fixed cropland availability within the 10-year production planning period ahead. From the resulting multi-year equilibrium solution, we take the first-year values of the endogenous commodity prices and use them to construct a composite commodity price index that is used to adjust the assumption about cropland availability for the next 10-year planning period (see Chen et al., 2014). To prevent unrealistic changes and extreme specialization in land use, we restrict CRD-specific row crop planting decisions to a convex combination (weighted average) of crop mixes in each CRD using methods described in Chen & Onal (2012). In the case of energy crops, we do not have historical crop mixes to constrain land-use change to their production. Energy crop production on cropland or cropland pasture occurs if the net discounted value of return from it is larger than the foregone returns from (or costs of conversion from) existing uses of these lands. To avoid the extreme changes in land use, between existing uses and energy crops, that could result from this we restrict the land allocated to perennial grasses (miscanthus and switchgrass) to less than 25% of total land availability in a CRD. This constraint is also intended to account for other factors such as inertia, transactions costs, risks and uncertainties that could limit the conversion of land to energy crops even if it were profitable to do so.

Transportation sector. Biofuel and Environmental Policy Analysis Model (BEPAM-E) includes linear demand curves for Vehicle Kilometers Travelled (VKT) with four types of vehicles, including conventional gasoline, flex fuel, gasoline hybrid and diesel vehicles (Chen et al., 2014). The VKT production function considers the energy content of alternative fuels, fuel economy of each type of vehicle and the forthcoming Corporate Average Fuel Economy standards, and technological limits on blending gasoline and ethanol for each of these four types of vehicles, as specified by EIA (2010a). Demand curves are exogenously shifted for VKT with each type of vehicles over time as projected by the Annual Energy Outlook (AEO) (EIA, 2010a) to capture the growth in demand due to changes in vehicle fleet, income and population. Transportation fuel demand can be met through a mix of liquid fossil fuels and biofuels. The supply of transportation fossil fuels is represented with upward sloping linear supply functions for both gasoline and diesel produced the United States and ROW (Chen et al., 2014). The supply of biofuels is derived from first-generation fuels, which include corn ethanol, biodiesel, and imported sugarcane ethanol, and from second-generation, cellulosic biofuels produced from the same types of feedstock used for bioelectricity generation (energy crops, crop residues and forest residues).

Policy. The federal RFS is implemented as a nested standard that sets a minimum annual requirement for cellulosic biofuels as projected annually by the AEO as a binding volumetric mandate (EIA, 2010a), but allows the mix of feedstocks used to meet them to be endogenously determined. There is an upper limit of 56 billion liters on corn ethanol after 2015 and a minimum requirement for 90 billion liters of advanced/cellulosic biofuels in 2030. As the RFS is implemented as a blend mandate, we estimate the blend rates that will achieve the volumetric targets each year 2007–2030 as in Chen et al. (2014) and impose those as binding annual blend mandates. As a federal mandate, the RFS provides flexibility in the amount of biofuels produced by any region and in the use of the lowest cost sources of feedstocks nationally, irrespective of which region they are located in.

This is in contrast to the state RPSs which will place demands on renewable energy resources for electricity generation that are region specific. Thus, the joint implementation of the state RPSs in the presence of the RFS has the potential to affect the mix of feedstocks and their regional production pattern to produce biofuels as well as the regional mix of renewable electricity generation. The implementation of the RFS as a blend mandate imposes an implicit tax on fossil transportation fuels and an implicit subsidy on biofuels; the net impact on the blended fuel price could be positive or negative depending on the magnitudes of the implicit subsidy and tax (De Gorter & Just, 2009; Chen & Khanna, 2013). The RPS is also implemented as a blend mandate, where the percentage of electricity generated from renewable sources must be no less than the amount specified by the mandate. An RPS may raise or lower the price of electricity depending on the relative elasticity of the renewable and non-renewable fuel supply curves and the stringency of the RPS target (Fischer, 2010). Furthermore, the RPS can reduce the marginal cost of electricity from renewables over time through learning-by-doing.

We model the state RPSs as a constraint that requires eligible renewable generation consumed in each EMR, to be no less than the specified share by the RPS times the total electricity consumed in each EMR. The state-level RPSs are averaged at the EMR level using annual generation-weighted averages to obtain a regional RPS. The RPS proportions parameters are calculated from the Database of State Incentives for Renewables and Efficiency (DSIRE, 2011). In general, these parameters represent the RPS for an EMR and are proportions that increase over time until the target percentage is achieved in a target year.
Electricity sector. Electricity generated at existing power plants is conditional on each plant’s generation capacity. The existing capacity of each power plant at the CRD level is parameterized based on the Emission and Generation Integrated Database (EPA, 2010). The capacity by power plant type is aggregated by CRD. The capacity factor for each CRD is calculated based on the weighted average on the plant capacity factor of all power plants of a specific type in a given CRD (EPA, 2010). The fixed and variable O&M costs of existing power plants are obtained from a version of the NEMS model (UCS, 2011).

The costs of electricity generated from new sources (excluding co-firing) consist of a levelized cost and a fuel cost. We define the levelized cost as the annualized fixed cost [converted to a cost per kilowatt hour (kWh) based on the expected generation over the life of the plant] and a variable operating and maintenance (O&M) cost per kWh (EIA, 2010a). Additional cost of electricity generation includes the fuel cost per kWh and transmission losses, which are endogenously determined depending on the fuel price and the extent of transmission across different regions as described in Oliver & Khanna (2017). The cost of modifying a coal plant for co-firing is assumed to be obtained from EIA (2010a). Feedstock heat content, conversion efficiency and processing cost are described in Oliver & Khanna (2017). All feedstocks are assumed to have the same heat content (Haq, 2002). A constant cost of transportation per kilometer per ton of biomass from its harvest location to a potential co-firing or dedicated bio-power plant is assumed based on Searcy et al. (2007). Total transportation costs for biomass are calculated by multiplying this with the distance between centroid of the biomass-producing CRD and the biomass-consuming CRD. We also include an exogenously given annual demand for pellets for export.

Wind energy supply curves are specified for each EMR and are based on data from the NEMS model (EIA, 2011a). These data are projections of the amount wind capacity that is available by region at multiples of a base capacity cost. These capacity supply curves are converted to generation supply curves using a given capacity factor and calibrated using a base levelized cost per megawatt hour (EIA, 2010a). The relative cost of wind energy will be a factor in determining the regional share of bioelectricity; we test the sensitivity of our results to this assumption by examining a lower wind energy cost.

The natural gas supply function is a linear upward sloping function representing the national supply of natural gas for all sectors. It represents the national wellhead price of supplying natural gas. The supply function is calibrated annually for the year 2007–2011 with the observed national average wellhead price and production over this period and an assumed value for the natural gas supply elasticity (see Oliver & Khanna 2017 for details on parametric assumptions). The supply curve is assumed to be fixed during a rolling horizon but shifts inwards in each subsequent rolling horizon according to projections by the Annual Energy Outlook (EIA 2012). Natural gas used for power generation incurs a regional transportation and distribution cost. Therefore, the regional delivered natural gas price for the electricity sector is a function of the endogenously determined national wellhead price plus the regional transportation and distribution cost. The demand for natural gas across sectors other than electricity is assumed to be exogenous. The supply of coal and fuel oil for electricity generation is assumed to be perfectly elastic at state-specific fixed prices; these prices are exogenously set annually, from observed data for 2007–2011 and from EIA growth rate projections for the following years (EIA, 2010b, 2012). The electricity demand functions are calibrated with parameters calculated from data on state electricity retail sales, retail electricity price and the price elasticity of demand for electricity as described in Oliver & Khanna (2017).

Agricultural sector. The agricultural sector consists of markets for primary and processed commodities and livestock products. Domestic and export demands for primary commodities, such as corn and soybeans, are determined in part by the demands for processed commodities obtained from them and by other uses (such as seed). We use two-year (2006–2007) average prices, consumption, exports and imports of crop and livestock commodities to calibrate the domestic demand, export demand and import supply functions for all commodities. Sources of data on prices, consumption, exports and imports are described in Chen et al. (2014). Domestic demands, export demands and import supplies are shifted upward over time at exogenously specified rates. The simulation model incorporates CRD-specific data on costs of producing crops, livestock, biofuel feedstocks, yields of conventional and bioenergy crops, and land availability. We estimate the rotation-, tillage- and irrigation-specific costs of production in 2007 prices for fifteen row crops (corn, soybeans, wheat, rice, sorghum, oats, barley, cotton, peanuts, potatoes, sugar beets, sugarcane, tobacco, rye and corn silage) and three perennial grasses (alfalfa, switchgrass and miscanthus) at county level. These are then aggregated to the CRD level for computational ease. Production of dedicated energy crops is limited to the rain-fed regions of the United States to the east of the 100th meridian. Domestically produced feedstocks used for biofuel production in the model include corn, corn stover, wheat straw, forest residues, miscanthus, switchgrass, waste grease, vegetable oils, DDGs and pulpwood.

County-specific corn stover and wheat straw availability are proportional to historically observed grain yields, and their harvest rates are limited to levels that depend on tillage practices to prevent soil degradation. The incremental costs of producing them include the cost of harvesting and replacement fertilizer application. Energy crops have the potential to be grown productively and at low cost on low-quality land (Khanna et al., 2011; Dwivedi et al., 2015). County-specific yields of miscanthus and switchgrass on two types of land qualities, high-quality cropland and low-quality cropland pasture, are simulated using the DayCent model (see Hudiburg et al., 2016). As the mix of feedstocks used for bioelectricity generation and biofuel production is sensitive to their yields, we examine a case where yields are lower than those simulated with the DayCent model. Their cost of production is estimated using methods described in Chen et al. (2014) and Dwivedi et al. (2015).

We obtain CRD-specific data on land availability for each of the five types of land (cropland, idle cropland, cropland pasture,
pasture land and forestland pasture) from USDA/NASS (2009). CRD-specific planted acres for 15 row crops are used to obtain the cropland available in 2007 and to obtain the historical and synthetic mixes of row crops. Cropland availability in each CRD is assumed to change in response to crop prices following acreage price elasticities estimated in Miao et al. (2016). Data on idle cropland, cropland pasture, pasture and forestland pasture for each CRD are obtained from USDA/NASS (2009). The analysis here assumes that land enrolled in CRP is preserved at 2008 levels and not used for conventional crop or bioenergy crop production as in Chen et al. (2014).

Transportation sector. Biofuel and Environmental Policy Analysis Model (BEPAM-E) includes linear demand curves for VKT with four types of vehicles, including conventional gasoline, flex fuel, gasoline hybrid and diesel vehicles, and a VKT production function for each type of vehicle. We exogenously shift demand curves for VMT with each type of vehicle over time as projected by the Annual Energy Outlook (EIA, 2010a,b) to capture the growth in demand due to changes in vehicle fleet, income and population. Gasoline and diesel supply curves are calibrated for 2007 using data on fuel consumption and production in the United States and for the rest of the world. Key assumptions about demand elasticity for VKT and supply elasticities of fuels are reported in Chen et al. (2014).

The biofuel sector includes several first- and second-generation biofuels. First-generation biofuels include domestically produced corn ethanol and imported sugarcane ethanol, soybean biodiesel, DDGS-derived corn oil and waste grease. Second-generation biofuels included here are cellulosic ethanol and biomass-to-liquid diesel produced using the Fischer–Tropsch process. The feedstock costs of biofuels consist of two components: a cost of producing the feedstock which includes costs of inputs and field operations, and a cost of land. Methods for estimating costs and the technological parameters for converting feedstock to different types of biofuel and the industrial costs of processing feedstocks and producing biofuels are described in Chen et al. (2014). These costs are assumed to decline due to learning-by-doing as cumulative production increases using an experience curve approach (see Oliver & Khanna, 2017).

Results
We first validate the model by examining the extent to which the simulated results deviate from the observed levels in the initial model year of 2007. We find that electricity generated from coal and natural gas sources and total electricity generation was deviated by less than 4% from the observed data. Average national electricity price deviates by 14%, and the national wellhead natural gas price deviates by 7% (for further details, see Oliver & Khanna, 2017).

For the purposes of this analysis, we consider three policy scenarios and compare them to a no-policy scenario and examine outcomes over the 2007–2030 period for the electricity, agricultural and transportation sectors. Scenario 1 is the no-policy baseline scenario in which there is no renewable energy policy; we do, however, assume the presence of the Corporate Average Fuel Economy Standards, the excise tax on fuel and a low (3%) blend of ethanol for oxygenation. In Scenario 2, we constrain the eligible renewable generation consumed in each EMR to be no less than the regional RPS. In Scenario 3, we implement the RFS by imposing the annual volumetric targets for biofuels projected by the AEO as a binding mandate (EIA, 2010a). The RFS is implemented as a blend mandate with binding constraint on blend rates estimated to achieve the annual volumetric targets grow from 6% in 2007 to 24.5% in 2030 as in Chen et al. (2014). We find that this blend and level of biofuel consumption is achievable given the projections for flex-fuel vehicle demand by the Annual Energy Outlook (EIA, 2010a). By assuming the absence of demand-side constraints for blending biofuels, this analysis examines the supply-side implications of these renewable energy policies for biomass production. In Scenario 4, the RPS & RFS scenario, the RFS and state RPSs are implemented jointly as described above.

Effects of alternative policies on mix and level of electricity generation
The RFS increases renewable energy generation by 68% compared to the no-policy case, which increases the share of renewable energy in total generation from 10% to about 16% in 2030. It also reduces the generation from coal and natural gas by 5% and 13%, respectively. Nevertheless, total generation increases by 1.4% compared to the no-policy case. The amount of bioelectricity generated under the RPS is 140 M MWh; this requires about 87 MMT of biomass. The RFS has a negligible impact on renewable energy generation and increases renewable generation by 4% mainly due to coproduct electricity generation, which displaces natural gas-based electricity. The increased demand for biomass for cellulosic biofuel under the RFS raises the price of biomass and makes co-firing biomass with coal expensive. This results in a reduction in co-fired electricity generation and an increase in coal-based electricity generation. The effects of the joint implementation of the RFS & RFS on the electricity sector are very similar to those under the RFS alone, with total generation increasing by 2%, and the share of renewable energy increasing to about 16% (Table 1).

Under the no-policy scenario, bioelectricity and wind account for about 9% each of the total renewable electricity produced with the remaining 82% largely from hydroelectric sources and small quantities of solar, geothermal and other renewables. The implementation
The effects of alternative policies on various energy sources in 2030 are presented in Table 1.

| Energy source                                | No policy | RPS | RFS | RFS & RPS |
|----------------------------------------------|-----------|-----|-----|-----------|
| **Total electricity generation (M MWh)**     | 4372      | 1   | 1   | 2         |
| Renewable-based (M MWh)                      | 418       | 68  | 4   | 68        |
| Share of renewables (%)                      | 9.6       | 16  | 10  | 16        |
| Fossil fuel-based (M MWh)                    | 2998      | -8  | 0   | -7        |
| Coal                                         | 1899      | -5  | 1   | -2        |
| Natural gas                                  | 1099      | -13 | -2  | -14       |
| **Sources of renewable electricity generation (%)** |           |     |     |           |
| Co-firing                                    | 9         | 16  | 3   | 9         |
| Dedicated biomass                            | 0         | 4   | 0   | 3         |
| Coproduction                                 | 0         | 0   | 9   | 6         |
| Total bioelectricity                         | 9         | 20  | 12  | 17        |
| **Wind**                                     | 9         | 31  | 9   | 34        |
| **Total biofuels (billion liters)**          | 19        | 19  | 147 | 146       |
| **Total biomass (M MT)**                     | 33        | 100 | 262 | 310       |
| **Biomass from agriculture (%)**             | 0         | 55  | 85  | 75        |
| **Biomass from forest (%)**                  | 100       | 45  | 17  | 25        |
| **Biomass for bioelectricity (%)**           | 60        | 87  | 3   | 17        |
| **Biomass for cellulosic biofuel (%)**       | 0         | 0   | 95  | 79        |
| **Biomass for pellet exports (%)**           | 0         | 13  | 2   | 4         |
| **Sources of feedstock (%)**                 |           |     |     |           |
| Corn stover                                  | 0         | 37  | 48  | 46        |
| Wheat straw                                  | 0         | 7   | 9   | 11        |
| Miscanthus                                   | 0         | 11  | 26  | 19        |
| Switchgrass                                  | 0         | 0   | 3   | 0         |
| Forest residues                              | 100       | 44  | 17  | 14        |
| Pulpwood                                     | 0         | 1   | 0   | 11        |

The RPS would significantly expand the share of bioelectricity to 20% (with a 16% share of co-fired generation and 4% share of dedicated bioelectricity) and of wind generation to 31%. In contrast, the RFS would increase coproduct-based bioelectricity generation while reducing co-fired electricity generation. The RFS & RPS would result in a slightly lower share of bioelectricity (17%) and a higher share (34%) for wind generation than under the RPS (Table 1).

**Effects of alternative policies on mix and volume of biofuels**

Under the assumed targets of the RFS, the total volume of biofuels increases to 147 billion liters in 2030. Corn ethanol production is at the capped level of 57 billion liters. Additionally, the RPS induces 8 billion liters of advanced biofuels (imported sugarcane ethanol and renewable diesel) and 82 billion liters from cellulosic feedstocks. As the RPS creates no incentives for biofuel production, biofuel production under the RFS & RPS is close to that under the RFS alone (Table 1).

**Feedstock production and mix**

The demand for bioelectricity and biofuels creates a demand for biomass that increases from 33 million metric tons (MMT) under the no-policy scenario to 100 MMT under the RFS and to 262 MMT under the RFS. The combined demand for biomass under the RFS & RPS is 310 MMT in 2030. This is less than the sum of the demand for biomass under RPS and RFS individually because the higher price of biomass under the combined policy reduces the competitiveness of bioelectricity in favor of wind generation. Of the total biomass produced, 87% is used for bioelectricity under the RPS (and the rest exported as pellets), but 95% is used for biofuel under the RFS. With both RFS & RPS implemented jointly, about 80% would be used for cellulosic biofuels and 17% for bioelectricity.
Of the total biomass produced under the various scenarios, a dominant share ranging from 55% to 85% is from agricultural feedstocks and the rest from forest residues and pulpwood. Crop and forest residues have the potential to account for almost 88% of the biomass under the RPS. This share decreases to about 70% under the RFS and under the RFS & RPS. Dedicated energy crops provide 11–29% of the biomass under the three scenarios with miscanthus having a dominant share among the energy crops produced.

Figure 1 shows the trend in the mix and quantity of biomass over the 2007–2030 period under the three alternative policy scenarios. Under the RPS (Fig. 1a), total biomass feedstock production increases over time, although the rate of increase slows over time; the growth in biomass feedstock demand corresponds to the increasing stringency of the RPSs over time. The mix of feedstock initially consists primarily of forest residues, but the proportion of corn stover, wheat straw and energy crops increases over time; by 2030, the share of feedstock from agriculture is 55% and from 44% from forest (Table 1). Corn stover makes up a large percentage of the total feedstock as it is relatively less costly to produce than other feedstocks in many areas, particularly those which have a high corn yield. Over 75% of the corn stover produced is utilized in the CRD in which it is produced and is therefore, not incurring an additional transportation costs, while the rest is consumed for co-firing in coal-based power plants in neighboring CRDs from the source of production. These results are in contrast to those obtained by Sands et al. (2017) who assume that all of the bioelectricity generation determined here, the large share of crop residues in biomass supply and the relatively higher yield of miscanthus as compared to switchgrass.

The RFS and the RFS & RPS scenarios see a large increase in land use of about 4–5 million hectares relative to the no-policy scenario. Much of this increase in cropland is to produce energy crops as cropland pasture is converted to energy crop production to produce the additional feedstock required to meet the biofuel mandate. Land for food crop production under the RFS & RPS is only marginally lower than under the RFS alone, as a greater share of biomass is gathered from crop residues than under the RFS scenario only. This is likely due to the spatial distribution of the RPSs, which require biomass production in particular regions where crop residues are a lower cost source of biomass than energy crops.

Figure 2 shows the spatial pattern of biomass production in 2030 under the alternative policies. As shown in Fig. 2a, much of the production of biomass under the RPS occurs in areas where there are coal-based power plants that can co-fire biomass. The largest concentration of biomass feedstock production occurs in the Illinois and Missouri region at a level of about 14 M MT (Fig. 2a). Under the RFS & RPS scenario, production of agricultural and forest biomass for bioelectricity decreases relative to the RPS scenario (Fig. 2b). Much of the feedstock production for bioelectricity in upper

### Table 2 Prices in 2030

|                          | No policy | RPS | RFS | RFS & RPS |
|--------------------------|-----------|-----|-----|-----------|
| Electricity price (average cents kWh) | 11.5      | 11.2| 11.3| 11.0      |
| Coal generation (max of all technologies) | 5.3       | 5.2 | 5.3 | 5.1       |
| Natural gas generation price | 8.8       | 8.3 | 8.8 | 8.3       |
| Co-fired electricity | 6.0       | 7.8 | 7.1 | 9.2       |
| Dedicated biomass         | n/a       | 16.6| n/a | 20.0      |
| Wind                     | 13.0      | 15.0| 13.0| 14.9      |
| Natural gas price ($/MMBtu) | 4.40      | 4.02| 4.34| 3.96      |
| Farmgate biomass feedstock price ($/MT) | 35.3      | 53.4| 59.3| 87.9      |
| Land rental rate (average $/ha) | 502       | 495 | 677 | 676       |

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Midwest and Southeast that would occur under the RPS is entirely redirected toward biofuels under the RFS & RPS scenario as shown in Fig. 2d.

Under the RFS & RPS scenario, the intensity of biomass production increases in the rain-fed region of the United States (east of the 100th meridian) relative to the RPS alone. Production of biomass is particularly concentrated in Illinois, Tennessee, Missouri, Eastern Texas and the South Central region. Figure 2c, d shows biomass production for biofuels under the RFS and the RFS & RPS scenarios. Under the RFS & RPS scenario, crop residue production in the northern and north-western regions of the United States increases, while energy crop production in the south and south central region is reduced relative to the RFS alone (Fig. 2d).

Effect of alternative policies on the prices

We now discuss the effects of the renewable energy policies considered here on the price of electricity, the price of biomass and the price of land. The price of electricity varies across EMRs and is determined by the demand and supply of electricity in the region. The price of biomass and the price of land vary across CRDs because land availability and land costs are defined at the CRD level. Price of food crops is determined at the
national level given the national markets for agricultural commodities.

The farmgate price of biomass feedstock at the CRD level depends on the quantity of biomass production in the CRD, the CRD-specific biomass yields, land availability and costs of production (Fig. 3). In the RPS scenario, the price of biomass feedstock varies across the United States and has average price of $53/MT. The average price of biomass under the RPS is higher at $59/MT. The RFS & RPS results in an even larger increase in biomass price to $88/MT. Under each of these policies, there is considerable spatial variability in the price of biomass, as shown in Fig. 3. In the Midwest, where the greatest amount of feedstock is produced, the price of biomass under the RPS ranges from about $46–$75/MT. In the Northeast, the price ranges from about $76–105/MT. The highest feedstock prices are found in the Southwest, but the quantity produced is relatively low. The range of biomass prices under the RFS & RPS scenario is much higher than under the RPS alone due to the increased level of production to meet the higher demand for biomass. In the Midwest prices range from about $76–105/MT, while in the Northeast prices range from about $106–135/MT. There is not much transportation of biomass across regions with new bioelectricity plants and biorefineries assumed to be established in CRDs with low costs of biomass production.

Bioelectricity prices also vary across regions, scenarios, and sources. Co-firing electricity tends to be less costly than electricity from a bio-power plant, which has a lower heat rate (conversion efficiency) of the bio-power plant than a co-fired process. Co-firing, however, is more expensive than coal-based generation, which costs on average about 5.3 cents kWh\(^{-1}\) (Table 2). These costs vary by region based on the conversion efficiency of existing coal-based plants and/or biomass transportation cost that depends on the distance travelled by the biomass. The average price of electricity from co-firing increases from 7.8 cents kWh\(^{-1}\) under the RPS to 9.2 cents kWh\(^{-1}\) under the RFS & RPS (Table 2). The average price of electricity from a bio-power plant increases from 16.6 cents kWh\(^{-1}\) under the RPS to 20 cents kWh\(^{-1}\) under the RFS & RPS. Regions such as CO, WY and IN, OH, WV, NJ have relatively lower

Table 3  Land-use implications of biomass production in 2030 (million hectares)

|                      | No policy | RPS | RFS | RFS & RPS |
|----------------------|-----------|-----|-----|-----------|
| Total cropland       | 120.0     | 120.5| 125.0| 124.0     |
| Land under food crops| 117.0     | 116.8| 109.1| 108.9     |
| Land under corn      | 3.0       | 3.0  | 11.6 | 11.6      |
| for ethanol          | 0.0       | 0.7  | 4.3  | 3.5       |
| Land under energy crops| 0.0     | 0.2  | 3.9  | 2.7       |
| From regular cropland| 0.0       | 0.4  | 0.3  | 0.8       |
| From marginal land   | 0.0       | 0.2  | 3.9  | 2.7       |
| Land under corn      | 0.0       | 6.9  | 24.3 | 27.6      |
| stover               |           |      |      |           |
| Land under wheat straw| 0.0      | 2.7  | 10.6 | 16.1      |

Fig. 2  Spatial pattern of biomass production in 2030 in million metric tons. Dots indicate existing coal power plant locations. (a) Biomass production for electricity under Renewable Portfolio Standard (RPS). (b) Biomass production for cellulose ethanol under RFS. (c) Biomass production for electricity under Renewable Fuel Standard (RFS) & RPS. (d) Biomass production for biofuel under RFS & RPS.

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bioelectricity prices under both scenarios as they rely only on lower cost co-firing, while regions like CT, ME, MA, NH, RI, VT and NY have relatively high bioelectricity price under both scenarios, due to use of higher cost bio-power plants and relatively stringent RPSs. The increase in the average price of bioelectricity across regions with the combined RFS & RPSs implies an increase in the implicit subsidy that goes toward bioelectricity, which corresponds to an increase in the welfare cost of the policy (Oliver & Khanna, 2017).

We find that the increase in total electricity generation under the RPS leads to a marginal reduction in the average price of electricity. The reduction in coal and natural gas generation reduces the price of natural gas and the cost of fossil fuel-based electricity but increases the marginal cost of renewable electricity from bioelectricity and wind. The higher price of biomass under the RFS & RPS results in a higher average cost of bioelectricity, which increases from 16.6 cents kWh\(^{-1}\) under the RPS alone to 20 cents kWh\(^{-1}\) under the RFS & RPS.

We also find that the increased demand for biomass, particularly from energy crops, and the demand for corn for ethanol under the RFS and the RFS & RPS lead to an increase in the rental value of land. The land rental rate increases by 35% from $502 per hectare under the no-policy scenario to $677 per hectare under the RFS and the RFS & RPS scenarios.

**Sensitivity analysis**

We now examine the robustness of our findings about the effects of alternative policy scenarios on some key policy outcome variables of interest to parametric assumptions in the model. The policy outcome variables we examine are: bioelectricity generation, biomass quantity, average biomass price and land required for energy crop production. As compared to the benchmark case, we consider alternative parametric assumptions that: (i) increase the maximum biomass blend rate for co-firing to 20% instead of 10%, (ii) lower the rate of coproduct electricity production per liter of ethanol from a cellulosic ethanol refinery by 25% compared to the benchmark level based on (Humbird et al., 2011), (iii) lower the marginal cost of wind generation by 25% than in the benchmark case (EIA, 2010a), (iv) raise the conversion efficiency of dedicated bio-power plants by 30% and (v) lower the yields of energy crops obtained from the simulation model DayCent by 20% (Dwivedi et al., 2015).

In general, we find that the amount of bioelectricity generated decreases under the RFS & RPS scenario compared to the RPS scenario only, across all policy scenarios except for the case when the marginal cost of wind electricity is relatively low (Fig. 4a). This is consistent with the finding shown in Fig. 4d that the price of biomass under the RFS & RPS scenario is substantially higher ($61–$104/MT) than in the RPS scenario.
($46–$59/MT). The extent to which this is the case is much lower in the scenario with the relatively low wind energy cost. In this case, the demand for bioelectricity under the RPS is less than a third of the demand in the benchmark case. This increases marginally under the RFS & RPS scenario due to the coproduct electricity generated. However, the overall demand for biomass is much lower in this scenario compared to the benchmark and other scenarios.

The relatively higher price of biomass under the RFS & RPS scenario accompanies the larger amount of biomass produced relative to the RPS scenario only. Across all the parametric assumptions, we find that the demand for biomass ranges between 52 and 168 MMT under the RPS and between 282 and 343 MMT under the RFS & RPS scenarios. Demand for biomass is lowest in the case with relatively low wind energy generation cost. Land requirement for biomass under the RFS & RPS is largely driven by the mandate for cellulosic biofuels and thus does not vary much with the variations in parametric assumptions considered here. Land requirements for biomass under the RPS are very small, ranging from 0.1 to 0.7 million hectares; it is much larger under the RFS & RPS and ranges from 2.9 to 3.8 million hectares. Land conversion to energy crops is lowest in the scenario with 25% lower energy crop yields because that makes energy crops less competitive with crop residues and forest biomass. Overall, we find that the qualitative direction of our findings under the benchmark case is robust to assumed parameter values in the model.

Discussion

This paper examines the demand for biomass likely to be generated by existing renewable energy policies in the electricity and transportation sectors in the United States over the 2007–2030 period. We apply a dynamic, partial-equilibrium, open-economy, sector model (BEPAM-E) of the US agricultural, electricity and transportation sectors to endogenously determine the share of bioelectricity to meet the state RPSs and the allocation of biomass between electricity and cellulosic biofuel production to meet the RPS. We also examine the mix of biomass likely to be produced from agricultural and forestry sources and from residues vs. dedicated energy crops and its implications for the land requirements to meet the biomass demand.

We find that bioelectricity could provide 20% of the renewable electricity needed to meet state RPSs in 2030 and generate a total demand for biomass of 100 MMT (including pellets for export). In contrast, the quantity of biomass needed under the RFS in 2030 is 262 MMT. If implemented together, the two policies would induce a demand for 310 MMT, which is less than the sum of the demand that would be generated under each of the policies independently. This is due to the increase in price of biomass induced by the simultaneous implementation of

Fig. 4  Sensitivity analysis. (a) Bioelectricity generation (M MWh). (b) Biomass production (M MT). (c) Land for biomass (M hectares). (d) Average biomass price ($/MT).
the RFS & RPS relative to that under each of the policies independently; implementation of the RFS reduces the competitiveness of bioelectricity relative to wind energy generation.

We find that crop and forest residues could meet more than 70% of the demand for biomass under the policy scenarios considered here. The remaining supply of biomass can be achieved by converting 0.7 million hectares under the RFS and 4.3 million hectares of land under the RFS to high-yielding energy crops. Under the RFS & RPS scenario, 3.5 million hectares would need to convert to energy crop production; 80% of this land could be from marginal land in pasture/grazing/crop rotation, while the rest would be from regular cropland.

This shows the potential to meet a significant portion of the demand for biomass likely to be generated by existing renewable energy policies without diverting land from food crop production.

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Supporting Information

Additional Supporting Information may be found online in the supporting information tab for this article:

Table S1. Electricity market regions and RPS (DSIRE, 2011).

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