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Drop-in biofuels offer strategies for meeting California's 2030 climate mandate

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Abstract

In 2015, California established a mandate that requires on-road greenhouse gas (GHG) emissions to be reduced by 40% below 1990 levels by 2030. We explore the feasibility of meeting this goal by large-scale commercialization of drop-in biofuels. Drop-in biofuels, although not clearly defined, are a class of fuels that can be produced from biomass and blended with either crude oil or finished fuels without requiring equipment retrofits. This article focuses on thermochemical routes at or near commercialization. We provide a bottom-up, spatially explicit cost analysis to evaluate whether California can meet its 2030 GHG reduction target with drop-in fuels alone. A takeaway from our analysis is that drop-in fuels, if their performance is consistent with small-scale and simulated results, can be viable low-carbon substitutes for gasoline and diesel. We find that California can meet, and even exceed, its 2030 GHG emissions target for on-road vehicles with drop-in biofuels alone, but this requires use of biomass resources located outside the state. Meeting the 40% reduction target in a cost-effective manner requires pyrolysis of herbaceous agricultural residues (96% of total fuel output) and the conversion of woody residues via methanol-to-gasoline (4%). This scale of production would require 58 million metric tons of biomass feedstock, or 20% of total available biomass residues in the United States. For comparison, California is responsible for 11% of transportation-related petroleum consumption in the US. The approximately 5 billion gallons (19 billion liters) per year of drop-in fuel would displace 30% of gasoline and 60% of diesel demand in California. If electricity offset credits are eliminated, the target can be met with a similar scale of production, but methanol-to-gasoline becomes the dominant route (>99%), biomass requirements increase by 33%, and average production costs increase by 20%. Following this policy pathway would increase national biofuel production by 30% relative to 2015 production levels.

Introduction

In April of 2015, California's Governor issued an executive order that mandates a California greenhouse gas (GHG) reduction target of 40% below 1990 levels by 2030. The purpose of the order was to position the state along a trajectory to meet the upcoming 2050 GHG emissions reduction target established by the Global Warming Solutions Act of 2008 or AB32. The state's success in achieving this goal, and the

means by which it is reached, have broad implications; California has the largest economy of any state in the United States (US), accounting for nearly one seventh of the country's gross domestic product (GDP) and 11% of transportation-related petroleum demand. Instituting policies aimed at mitigating GHG emissions from the transport sector will be vital [1] as the transport sector is the state's greatest contributor (37.3%) followed by the industrial (21.9%) and electricity (20.8%) sectors. California has taken a

portfolio-style approach to lowering the GHG emissions from its on-road transportation sector. Policies include incentives for the adoption of 'zero emissions vehicles' or ZEVs (implying zero tailpipe emissions, not life-cycle); the adoption of more fuel-efficient vehicles; the adoption of alternative fuel vehicles; and direct regulation of the GHG intensity of its transportation fuels. Although electrification of a large portion of the transport sector is ultimately crucial, some modes/vehicles are more challenging to electrify (e.g. heavy-duty freight), and the speed of this transition is tied to the turnover of vehicles in the fleet [2]. In previous studies, biofuels have been relegated to playing only a minor role in meeting the state's GHG targets [3, 4].

The role for biofuels in transportation sector emissions reductions has historically been constrained by the extent to which commercially-produced fuels (e.g., ethanol and biodiesel) can be technically blended into petroleum-derived fuels with required advanced vehicle equipment; failures to meet biofuel production targets are in part due to this blend wall and the difficulty in competing with conventional fuels while crude oil prices remain low. Limitations related to the blend wall, and other shortcomings in the implementation of the Renewable Fuel Standard program are explored more comprehensively by Lade *et al* [5]. Drop-in biofuel routes are not yet as technologically mature as ethanol production, but recent progress suggests that these fuels may be entering the market in greater volumes in the near future [6, 7], and climate change mitigation scenarios have yet to explore a future where this biofuel blend wall was completely removed. Going through the approval process for new blends takes many years and ethanol has approached the 10% blend wall, which in part is responsible for the lag in meeting state and federal advanced/cellulosic biofuel production targets. Eliminating the biofuel blend wall would require the formulation of blends that could serve as direct substitutes for gasoline and diesel at higher blending ratios without vehicle retrofits, referred to as *drop-in* fuels.

The term 'drop-in fuel' is not clearly defined in the literature. In an ideal case (from an engineering and economic perspective), a bio-based crude could be produced from biomass, shipped to petroleum refineries, processed alongside conventional crude without requiring equipment retrofits, and the resulting products would be indistinguishable from conventional petroleum fuels and products. However, the term 'drop-in fuels' has been used to refer to everything from bio-crude to hydrocarbon or higher-alcohol blendstocks. Since conventional petroleum fuels are themselves blended with additives to meet specific specs that vary by region and season, it is unlikely that any bio-based molecule or mixture will be a complete replacement. However, advanced biofuels could certainly increase the blend wall far beyond 10%, with some reaching near-100%. California, which has been

a leader in implementing state-level policy to decarbonize transportation, has expressed interest in these fuels. The state has adopted some drop-in fuel pathways into its version of Argonne National Laboratory's GREET model called CA-GREET [8], but policy analysts have yet to include drop-in fuels in broad GHG mitigation scenarios.

This paper aims to assess the impacts and resource needs of a rapid deployment of drop-in biofuel production to meet California's 2030 GHG reduction target for on-road transportation (e.g., light-duty cars and trucks, buses, motorcycles, and heavy-duty vehicles). We model the life-cycle GHG emissions associated with producing drop-in fuels using a geospatially- and temporally-explicit approach and evaluate whether California can feasibly meet its 2030 GHG reduction target with drop-in fuels alone. This approach is unique in that it considers pathways to mass commercialization of drop-in biofuels given the current topology of infrastructure systems—unlike the state's current approach in CA-GREET, which models pathways in a top-down fashion.

To scale-up the production of these fuels, we use an optimization framework with multiple objective functions and offer various strategies to meet or exceed California's 2030 GHG reduction target for on-road vehicles. However, achieving these targets requires that biomass resources be sourced from beyond state boundaries, and this is incorporated into the GHG emissions assessment. These routes are developed in a manner that minimizes the total cost of production while meeting the state's GHG mitigation goal. Each scenario offers insights into what types of feedstocks must be sourced, the scale of capital upgrades required to meet the goal, and the overall demands on freight transport.

Methods

Drop-in fuel pathway overviews

To determine which pathways are suitable for commercialization, we accounted for two primary factors: (1) the relative maturity and cost-competitiveness of the conversion process and (2) the compatibility of the conversion process with feedstocks widely available in the United States. Before ultimately narrowing our analysis to a limited collection of drop-in fuel pathways most relevant for California, we surveyed a wide array of potential production pathways including biological, hybrid biological/chemical, chemical, and thermochemical routes. More detail on these routes are included in the SI is available online at stacks.iop.org/ERL/13/094018/mmedia.

Each of the above-mentioned categories is capable of producing hydrocarbon fuels, either as a single compound or a complex mixture (as is the case for thermochemical routes). However, the yields, energy needs, and upstream emissions can vary dramatically.

Biological routes to drop-in fuels are promising but require further yield improvements to compete in the transportation fuel market without substantial financial incentives [9]. Thermochemical pathways, although providing less precision in the product(s) mix than biological routes, are more well-known and have a number of commercial implementations around the world [10]. For these reasons, our detailed analysis focuses on thermochemical routes, including pyrolysis [11–13], gasification with Fischer–Tropsch synthesis [14], and methanol-to-gasoline [15–17]. For each of these fuel pathways, we model the well-to-pump GHG footprint and approximate minimum selling prices based on techno-economic assessments performed by Department of Energy (DOE) national laboratory studies, which are highly standardized in terms of financial input parameters and guidelines for what constitutes *n*th plant performance.

Estimating the required emissions reductions

We established the GHG mitigation targets based on fleet composition (e.g., vehicle type, age, fuel) and technology (e.g., fuel economy, emissions control) data provided by the California Air Resources Board (CARB) [18]. The publicly available fleet data, which extends as far back as 1990, consists of four pieces of information useful for establishing a total GHG inventory for on-road vehicles operating in California: vehicle type, vehicle fuel source (ex., E10, diesel, or electricity), daily vehicle distances traveled, and tailpipe GHG emissions. We grouped vehicles into mode-specific categories (light-duty vehicles, motorcycles, buses, and heavy-duty vehicles) and calculated the total vehicle kilometers traveled (VKT) per year based on the total annual operation days by vehicle category [18].

Fuel economy statistics were compiled using a carbon-balance method for estimating fuel consumption rates given carbon dioxide, carbon monoxide (CO), and volatile organics emission (VOC) rates (although a very small fraction of carbon goes to CO and VOCs in modern vehicles). A summary of these estimates is provided in the SI. Lastly, we calculated the well-to-wheel GHG emissions for each mode using CA-GREET for E10- and low-sulfur diesel-powered vehicles [8]. CA-GREET provides estimates out to 2020, so we assume imputed the emission factor data out to 2030 using the latest projections for these respective fuels. For electric vehicles, we estimated electricity demand per kilometer driven based on projections provided by the US Energy Information Administration (EIA) [19]. The composition of primary fuel sources used to generate electricity (e.g., coal, natural gas, renewables, etc) in California, as well as the grids supplying electricity to other US regions, was estimated using electricity generation forecasts reported in the EIA's Annual Energy Outlook (2015) [19]. We used assigned fuel source-specific emission factors to each

grid mix and weighted these values based on total generated supply.

Biomass inventory and emissions

Solid biomass residues (e.g., crop residues, forest residues, mill wastes, and urban wood) are particularly attractive feedstocks from GHG reduction perspective. Since these otherwise underutilized products are wastes from crop production, forestland management, and other industrial activities, we assume that only emissions from harvesting activities and any required nutrient replacement (including net changes in on-field N_2O emissions) are allocated to the production of these resources. In terms of changes to soil carbon resulting from removal of crop residue, our estimates are based on removal of two-thirds of available biomass, which is generally considered to avoid negatively impacting soil quality (and even absent demand for bioenergy, residue may be removed at this rate for other uses such as bedding for livestock). This is the standard practice for GHG accounting in state and federal standards.

The methods described above may prove to be conservative, as many crop residues are still burned during seasons when such activity is not prohibited, and the resulting emissions can contain potent GHGs including CH_4. However, there are ongoing debates about the fraction of crop residue that can be sustainably removed and the impacts on soil organic carbon [20]. Any net losses in biogenic carbon from the soil as a result of residue removal should be accounted for. Such losses can be far greater when fallow land is tilled and brought into production. Because of direct and indirect land use change (LUC/iLUC) concerns associated with conversion of land to dedicated crops [21, 22], we considered only the availability of biomass residue feedstocks in our scenario analysis.

We constructed a county-level solid biomass residue inventory based on the DOE's Billion-Ton Study (BTS) [23, 24]. Our availability dataset was subdivided into three main types of biomass residues: forest residues, crop residues, and scrap wood, which is a combination of primary and secondary mill wastes as well as construction and demolition wood wastes. It should be noted that this study likely underestimates potential forest residue availability resulting from the recent drought and bark beetle infestation. However, improved inventories for California are still under development, and gross estimates on dead trees are likely to vastly overestimate the quantity of biomass that is economically recoverable. We chose to use the *Billion Ton* base scenario, which assumes that the US can sustainably harvest 297 mmt of solid biomass residues (crop: 70%; forest: 19%; scrap wood: 11%) in 2030. Next, we aggregated the county-level biomass inventory data into distinct cost bins, which varied from $10 to $200 per ton of biomass harvested.

Fuel production

Fuel production processes were modeled using stream tables developed in previous techno-economic assessments performed by DOE national laboratories, which go to great lengths to ensure key parameters are harmonized across Bioenergy Technologies Office funded research. Each assessment outlines the technical requirements to produce fuels at commercial scales, mass and energy balances, as well as process-level financial statistics using standardized assumptions. Information from the stream tables offered in each study was used to develop original emission factors for fuel pathways listed in table S9. Given differences in the technical composition and feedstock inputs, we treated each techno-economic study as its own technology within the broader class of fuel pathways. Whenever appropriate, we aligned our estimates of emissions rates to reflect pathways modeled in CA-GREET. When gaps between CA-GREET and the stream tables were identified, e.g., the GHG footprint of fuel catalysts, we relied on life-cycle emission factors found within a commercial LCA database [25]. Our estimates of fuel production costs exclude feedstock costs and electricity feed-in tariffs, which were calculated separately using location-specific data [19, 23, 26]. Table S9 summarizes the key inputs into our life-cycle GHG emissions and cost assessment.

Scale-up scenarios

As a part of a CARB-funded study, we developed a model that quantifies the environmental impacts associated with large-scale deployment scenarios for second-generation transportation fuels for use in California. The California Drop-In (CAdi) fuel logistics model uses mixed-integer linear programming to optimize biomass residue feedstock sourcing, the fuel types and locations of drop-in fuel producing facilities, and all of the upstream (e.g., between source and producer) and downstream (e.g., between producer and local storage) freight logistics required to bring these fuels to California markets. A technical overview of the model's configuration and the basis for its inputs is provided in the paper's supporting information is available online at stacks.iop.org/ERL/13/094018/mmedia.

In brief, the CAdi model's objective is to minimize the total GHG emissions associated with harvesting biomass, transporting feedstocks between sources and biorefineries, constructing the biorefineries, converting the biomass into fuel, and transporting the fuel to local markets within California. Each of these model components is evaluated from a life-cycle emissions perspective. In order to properly solve this facility-location problem, we had to first establish a set of candidate locations where drop-in fuels could be produced. Given the uncertainties associated with the evolution of land use over time in the US and t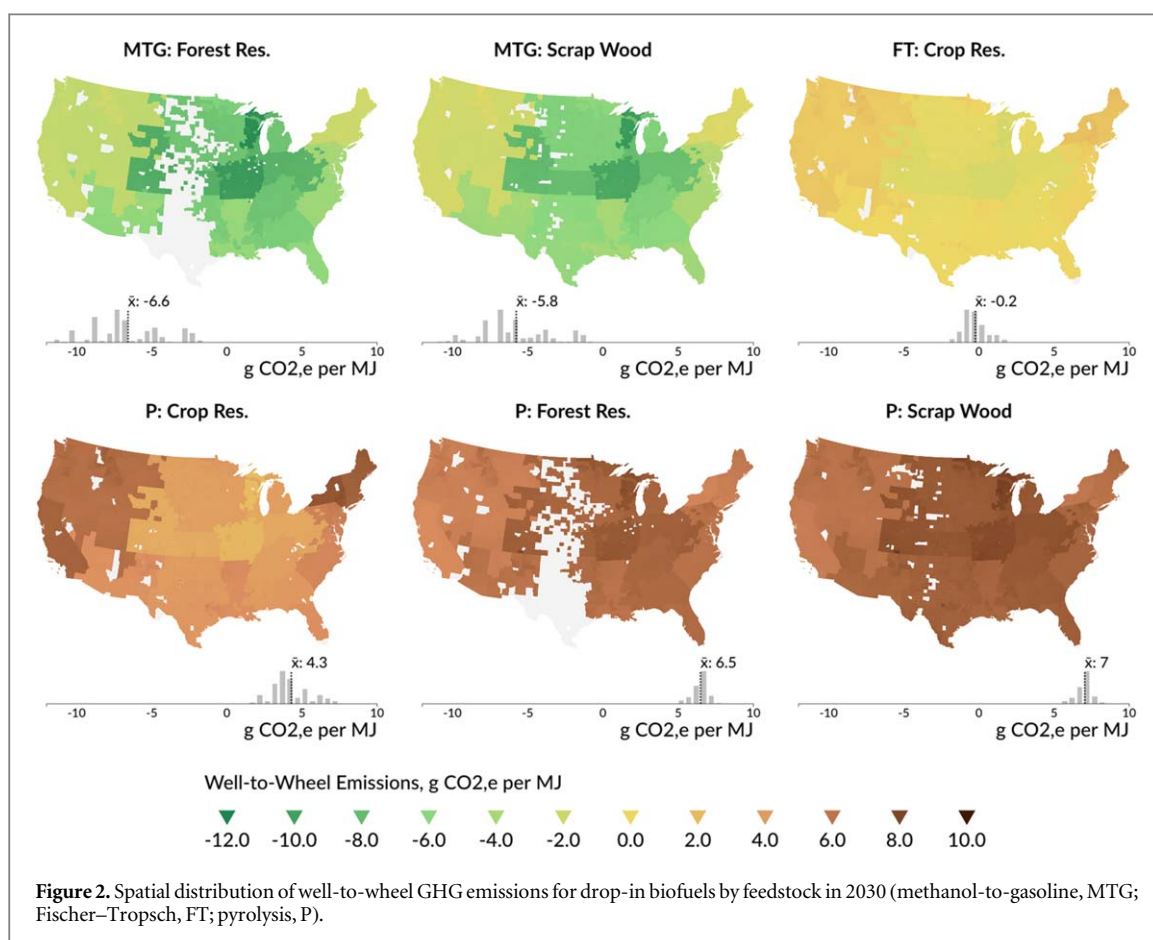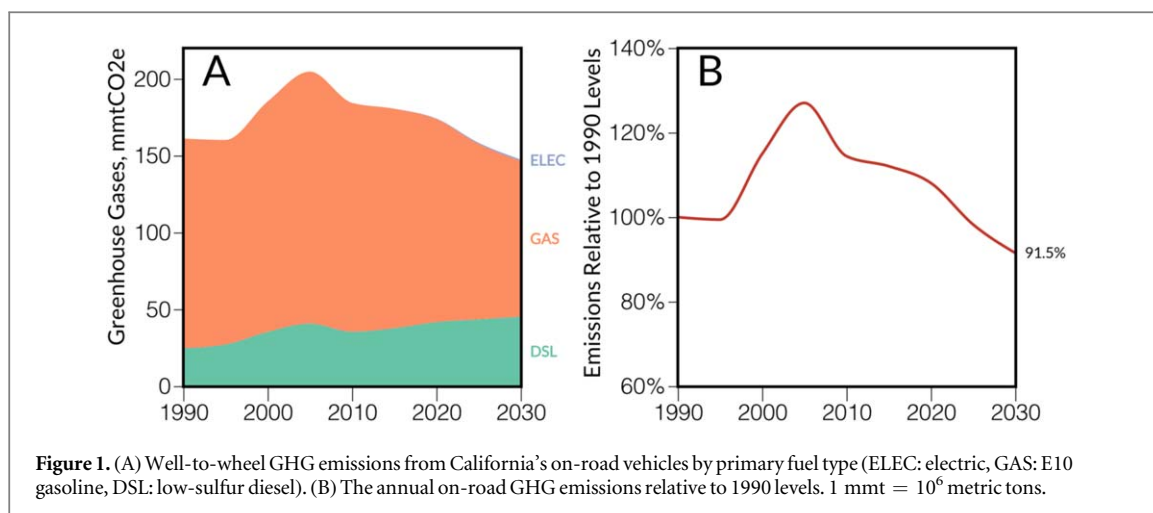he computational limitations of a significantly large number of potential sites, we limit the locations of potential drop-in fuel facilities to current (2016) petroleum ($n = 135$), ethanol ($n = 259$), and biodiesel ($n = 111$) refinery locations. The rationale for this co-location assumption is that some first-generation facilities may be retrofitted, and others may have an incentive to co-locate with facilities (like petroleum refineries) that can supply needed hydrogen for upgrading. In both the upstream and downstream model components, freight vehicles are routed between respective origin-destination pairs based on methods discussed in previous sections and more formally outlined in Taptich and Horvath (2015) [27]. Overall, the CAdi model is robust with over 1 million decision variables.

Our large-scale commercialization of drop-in fuels is based on the cost-optimal or market-driven pathway to meeting the goal. In addition to its essential constraints—biomass availability, conservation of mass, limits to demand for fuel, etc—an additional total cost constraint is applied to the CAdi model. This cost constraint establishes a national 'budget' for drop-in fuels, which is varied to find the cost-GHG emissions optimal frontier. From this frontier, the optimal set of policies can be established. Our frontier approach for this multi-objective analysis ensures that the market minimizes GHG emissions at the lowest cost to manufacturers.

Results

Hitting the target

Our analysis of CARB's baseline fleet inventory projections, which set the stage for our scenario assessments, reveals that GHG emissions from California on-road vehicles will likely be reduced, relative to 1990 levels, by 8.5% by 2030 (fleet total: 147.5 million metric tons $CO_{2,e}$ yr^{-1}) (figure 1). A summary of the total annual emissions and VKT by fuel type and vehicle category is provided in the supporting information (SI) in 5 year intervals. The general trends show that fleet average fuel economy increases by 120% between 1990 and 2030, and total VKT increases by 65%, which dampens the net benefits of more fuel-efficient vehicles. CARB projects 28 billion VKT by electric vehicles in 2030 (7% of state total), which is below the projections posed by the base scenarios in Greenblatt (2015). CARB's fleet composition numbers reflect business-as-usual policies and do not account for transformative changes in technology adoption trends. In total, additional GHG mitigation measures aimed at on-road vehicles will need to 'fill the gap' of 31.5% emissions reduction from 1990 levels, or an additional 50.78 mmt $CO_{2,e}$ yr^{-1} savings. Our scenarios intend to assess the feasibility of filling the emissions reduction gap with drop-in fuels, and the resulting feedstock needs in- and out-of-state to meet that goal.

Figure 1. (A) Well-to-wheel GHG emissions from California's on-road vehicles by primary fuel type (ELEC: electric, GAS: E10 gasoline, DSL: low-sulfur diesel). (B) The annual on-road GHG emissions relative to 1990 levels. 1 mmt $= 10^6$ metric tons.

Figure 2. Spatial distribution of well-to-wheel GHG emissions for drop-in biofuels by feedstock in 2030 (methanol-to-gasoline, MTG; Fischer–Tropsch, FT; pyrolysis, P).

The distributions of well-to-wheel GHG emissions vary by fuel pathway and solid biomass feedstock (figure 2). For each county, the fuel production process yielding the lowest emissions is shown for the 2030 reference year. Well-to-wheel GHG emissions vary from -11 to 8 g CO_{2e} MJ^{-1} (accounting for co-product credits). If electricity offset credits are eliminated, emissions vary from 0.6 to 10 g CO_{2e} MJ^{-1}. Indirect land use change (iLUC) is not incorporated in these emission factors because we do not include any dedicated bioenergy feedstock crops. For perspective, vehicles powered by E10 gasoline (using corn grain

ethanol), low-sulfur diesel, and electricity will emit approximately 80 g CO_{2e} MJ^{-1}, 97 g CO_{2e} MJ^{-1}, and 60 g CO_{2e} MJ^{-1}, respectively, in 2030 [8, 19].

Each normalized emissions footprint for drop-in fuel pathways is profoundly shaped by the carbon-intensity of electricity at the point of fuel production, more than any other life-cycle component (see, table S12). We include these credits in our emission factors because the system expansion method of co-product accounting continues to be the standard in the Renewable Fuel Standard and Low Carbon Fuel Standard, and system expansion is the approach preferred in ISO

14044 [28]. However, regulatory bodies must be cautious about double-counting these renewable electricity exports. Out-of-state renewable electricity generation should not be claimed for its GHG reductions in both California and in the home state. High carbon-intensity electricity markets, such as those found in the Midwest, favor drop-in fuel pathways that are net exporters of electricity (i.e., ISU 2013 [11, 12], PNNL 2009 [15], and NREL 2010 [14]). Electricity offsets could yield GHG reductions 8–22 times larger than the combined emissions from upstream and downstream transport. Table S12 also shows how these factors change when the electricity offset credit is eliminated; methanol-to-gasoline becomes most favorable from a GHG perspective, in part because this route benefits from a different co-product credit (liquefied petroleum gas, see table S9). Transportation and feedstock handling emissions are responsible for 17%–35% of total well-to-wheel GHG emissions. While the distances between fuel producers and California transportation fuel markets does contribute to the spatial variability of well-to-wheel GHG emissions and total transportation emissions, the magnitudes of electricity offset credits and total offsets have a greater impact on emissions.

This question of biomass and fuel production location raises an important point: if the Midwest does not have a sufficient market for bioenergy, and California's demand can drive additional production, it may be preferable from a GHG standpoint to produce fuels in the Midwest and important them to California. Conversely, if demand for biofuels in California results in market 'leakage' and results in lower biofuel supply to Midwest consumers, then the net system-wide benefits of a drop-in biofuel strategy will be diminished. Although the question of exactly if/how much biofuel supply would be reduced in the Midwest as a result of California's demand is beyond the scope of this study, it is an important topic for future research, and the results will be highly sensitive to the maximum blend walls for different advanced fuels (which is also currently uncertain).

At biorefineries located in California, drop-in fuel pathways that are net exporters of electricity (i.e., ISU 2013 [11, 12], PNNL 2009 [15], and NREL 2010 [14]) produce lower GHG emissions than net importers, except for methanol-to-gasoline pathways. For these fuels, the lower carbon-intensity grid (216 g CO_{2e} kWh^{-1} in 2030) and reduced freight demands favor the fuel pathway presented by the NREL 2011 study [16] (see, figure S6). Well-to-wheel GHG emissions, including electricity offset credits, vary from −4.9 to 6.8 g CO_{2e} MJ^{-1} across California. Excluding potential market 'leakage' impacts, we find that out-of-state producers can bring drop-in fuels to California markets at lower GHG emission rates.

Our results suggest that electricity offset credits have less of an influence on the technology selection process on a cost basis than they do for emissions (see
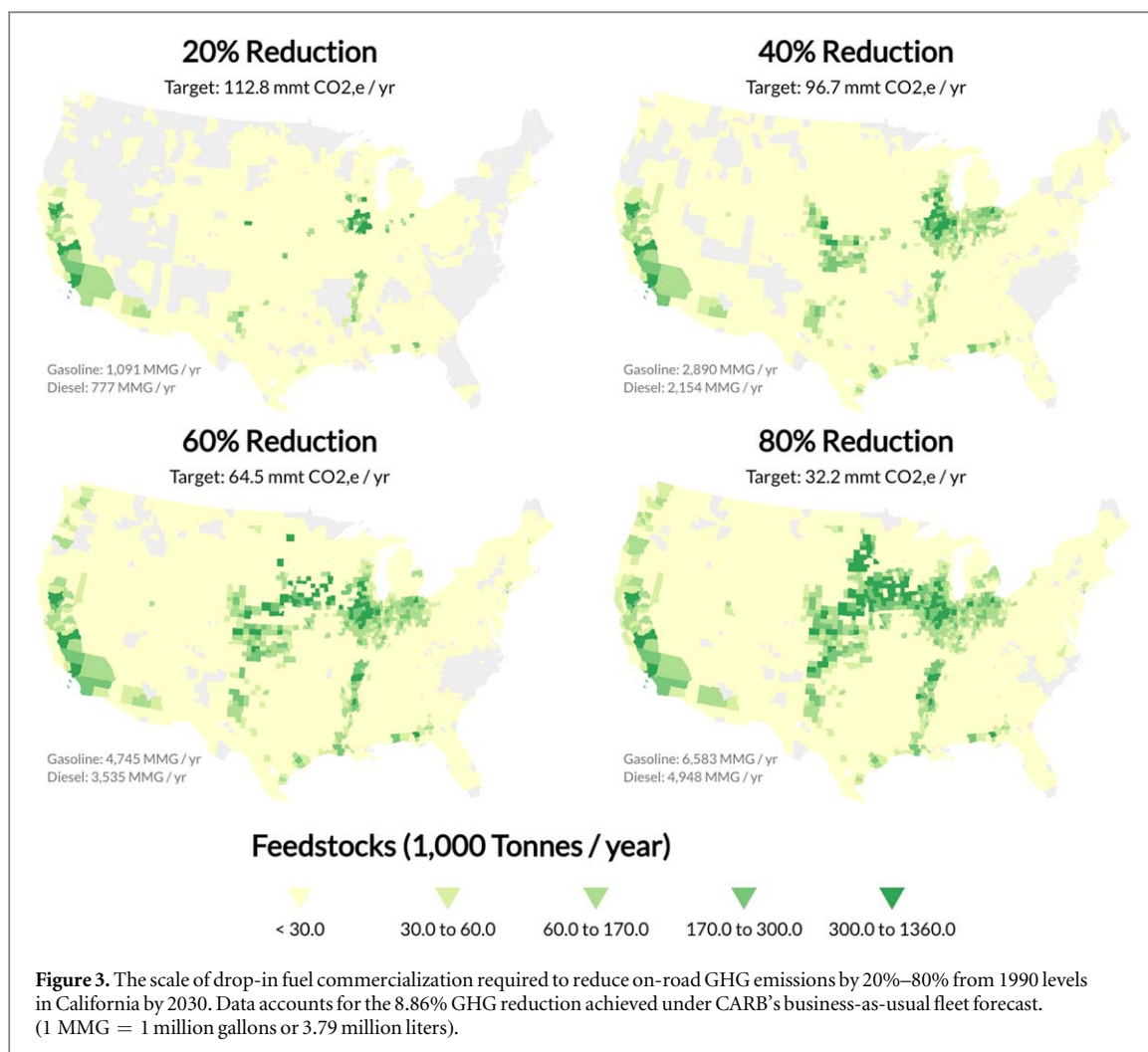
figures S7, S8 and table S12). Assuming a uniform feedstock cost of $80 per ton[5] for comparison purposes, the minimum-selling price for drop-in fuels range from $0.54/100 MJ to $1.05/100 MJ of fuel produced. Excluding transportation and feedstock handling costs improves the minimum selling price by 27%–52%, which is slightly higher than the process-by-process breakdowns for emissions outlined earlier. This would suggest that feedstock and product logistics have a greater effect on the spatially variable costs. Feed-in tariffs range from $0 to 0.07/100 MJ, or 0%–13% of the minimum-selling price. Again, the credits received from exporting electricity vary regionally; however, their relatively small contribution to total costs causes them to have less of an influence on the technology selection process. We find that fuel production costs are the single greatest determinant for selecting a fuel pathway technology. As a result, our results show that a single technology is best for each pathway-feedstock combination across all US counties (optimal technologies: NREL 2011 [16], NREL 2010 [14], ISU 2013 [11, 12], and PNNL 2013 [13]). Methanol-to-gasoline is the only fuel pathway with conflicting optimal technologies on an emissions and cost basis. These tradeoffs strengthen our claim that commercialization of these fuels for the purpose of reducing GHG emissions cannot optimally occur without the consideration of both emissions and costs, together.

Large-scale commercialization of drop-in biofuels

Based on our analysis, we find that California can meet, and even exceed, its 2030 GHG emissions target for on-road vehicles with drop-in biofuels alone but the optimal strategy requires biomass resources outside state boundaries (figure 3). To meet the 40% reduction target in a cost-effective manner, two fuel pathway technologies should be adopted: pyrolysis of herbaceous agricultural residues (based on ISU 2013 [11, 12], 96% of total fuel output) and the conversion of woody residues via methanol-to-gasoline (based on NREL 2011 [16], 4% of total output). This scale of production would require 57.9 mmt of biomass feedstock (94.6% crop residues, 1.2% forest residues, and 4.2% scrap wood), or 19.5% of available residues across the US. In contrast, eliminating any emissions credits for electricity exports (in a case where those exports are credited through different programs) results in a very different outcome: greater than 99% of fuel is produced using methanol-to-gasoline (< 1% produced using pyrolysis). This increases the biomass requirement by 33% because of the lower liquid fuel yield relative to petroleum. Requiring out-of-state biomass is not inherently problematic, as some sparsely-populated and agriculturally-rich states will

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[5] Data provided in the BTS suggests that feedstock handling costs range from $10 to $200 ton. We account for this variability in our commercialization scenarios.

Figure 3. The scale of drop-in fuel commercialization required to reduce on-road GHG emissions by 20%–80% from 1990 levels in California by 2030. Data accounts for the 8.86% GHG reduction achieved under CARB's business-as-usual fleet forecast. (1 MMG = 1 million gallons or 3.79 million liters).

likely require less than their total in-state resources. However, 19.5% is a larger fraction than, for comparison, the fraction of US population residing in California or the state's share of US GDP (both around 12%), indicating that without an increase in dedicated biomass production for bioenergy, California requires more than its proportional share of national biomass resources to meet its emissions goals. If the DOE/USDA *Billion Ton* goal is realized, this biomass demand would comprise less than 6% of nationally-available annual biomass resources. This issue warrants further research, as discussed previously.

The resulting 5044 million gallons (19, 117 million liters) per year of drop-in fuel production would displace 30% of total gasoline and 61% of total diesel demand in California. For comparison, applying no emissions credits for electricity offsets results in a total of 4681 million gallons of fuel, and effectively 100% would displace gasoline. Following this policy pathway would increase national biofuel production by 31% relative to 2015 production levels [29]. Under optimal conditions, feedstock collection would occur at different rates across the majority of the United States. Based on techno-economic assessments of each fuel pathway [11–17] and data provided by other

government/government-funded sources [23, 26, 30], we estimate that the feedstock-weighted minimum-selling price is $1.62 per gallon ($0.43 per liter) for *n*th plant production facilities. If no emissions credits are given for electricity exports, the minimum selling price in the optimal scenario rises to $1.95 per gallon.

Figure 3 illustrates the spatial variability in feedstock collection rates under various commercial scales. Three major harvesting regions can be depicted from the county-level maps. The first two regions occur outside of California and only focus on the collection of crop residues. These regions consist of the agricultural lands spanning from (i) Indiana to Kansas and (ii) juxtaposed to the Mississippi River from Louisiana to Northern Arkansas. In these regions, crop residues can be collected cheaply ($\bar{x}$ = $35/ton) and electricity is 2–2.7 times more carbon-intensive than California's grid. The CAdi model gives these areas greater preference, as the marginal emissions reduction potentials are high relative to total costs. California and its neighboring states represent the third harvesting region. This region focuses on both the collection of crop residues as well as woody biomass. Residue feedstocks collected in this region are cheaper ($\bar{x}$ = $25/ton) and supply chains are more

localized. The electricity available to fuel producers is less carbon-intensive than the rest of the country, so the reduction in variable costs allows these producers to be competitive with the other respective regions on the basis of cost of abated carbon. It is important to note that California does not have an adequate supply of residue biomass to meet its GHG reduction target of 40% below 1990 levels by 2030. Our analysis suggests that 87% of the counties in the lower 48 states would need to participate in feedstock collection operations. However, a more practical approach to meeting this target would be to focus new growth within the three major regions, as figure 2 implies that there is enough additional biomass to even exceed this target.

From an operations perspective, meeting the targeted 2030 GHG reduction levels requires significant capital investments and supply chain logistics. We find that an additional 317 biorefineries would be required by 2030, with average production levels around 16 MMG yr^{-1} of fuel reaching, at some facilities, well over 50 MMG yr^{-1}. Upstream freight operations are split 2:1 between truck and rail. In total, 4.0 billion additional ton-km of truck demand and 2.0 billion ton km of rail demand would be created annually, resulting in 0.56 mmt $CO_{2,e}$ additional GHG emissions per year. The average upstream trip length was 105 km. As the name suggests, 'drop-in' fuels can be directly inserted into our current petroleum product infrastructure, which is not the case for ethanol [31]. 36.6 billion ton km of pipeline demand, 1.6 billion ton km of rail demand, and 0.4 billion additional ton-km of truck demand would be created annually, resulting in 0.42 mmt $CO_{2,e}$ additional GHG emissions per year. It is important to note that the downstream freight logistics emit less GHGs than upstream, even though the total downstream freight turnover is 6.4 times greater. The reason for this is the GHG emissions factor for pipelines is 1 order of magnitude (OOM) less than rail and 2 OOMs less than truck; thus, the downstream operations have better 'low-carbon accessibility' [27] than upstream.

Discussion

Our analyses indicate that fuel production costs and electricity offset credits are the two most important determinants in the technology selection process, and the combination of low-cost biomass availability and relatively carbon-intensive electricity mixes makes out-of-state biomass and fuel production particularly attractive. The techno-economic analyses by the DOE national labs used in this study rely on consistent financial parameters, making them reasonably comparable. However, each of them relies on assumptions about future improvements in yields and overall system performance (referred to as *n*th plant assumptions), which, when factoring out feedstock costs and

electricity offset credits, results in minimum selling price projections that appear low relative to long-term fuel prices. Given the subjectivity of these *n*th plant projections, we assume the results are accurate within a 50% margin of error. We also assume electricity exports receive a carbon credit reflective of the average GHG emissions of the local grid. We acknowledge that there are many uncertainties regarding the manner in which the grid would rebalance to reflect this added supply, and also in the future changes in GHG intensity as older facilities retire and new ones come online. Studies suggest that the marginal GHG emission rates vary across the country [32], but accounting for these effects in 2030 was not possible. As a way of gauging the robustness of our findings, we offer additional scenarios that address these key issues.

We explored seven additional scenarios to explore the effect of different financial and technical assumptions on the ultimate conclusion that drop-in fuels can be commercially viable, low-carbon substitutes for gasoline and diesel. Table S13 summarizes the production scales and minimum selling prices for each scenario. Our assessments provide a number of key insights. First, if fuel production costs were two times higher than reported by the DOE labs, the anticipated minimum selling price (rack price) for drop-in fuels is $3.06/gal, which could presumably mean that these fuels remain commercially viable with some limited policy support or a modest rebound in future oil prices. Second, pyrolysis remains the preferred drop-in fuel pathway when electricity offsets are considered, although on-site char combustion may be a limiting factor in areas with air quality concerns. Methanol-to-gasoline becomes strongly favored if emissions credits are not applied to electricity exports from the biorefinery. When the financial and emissions credits from exporting electricity are removed from consideration, methanol-to-gasoline becomes the preferred drop-in fuel pathway. Lastly, we find that it is possible to meet and even exceed California's GHG reduction target of 40% below 1990 levels by 2030 under all scenarios.

There are a number of potentially influential factors that we did not consider in this study and to which future research should be directed. The factors include: (i) how competition for drop-in fuels may influence the net availability of the fuels in California markets; (ii) any blending restrictions regarding these fuels, similar to those found with ethanol; (iii) the effects of scaled economies on minimum selling prices as well as GHG emissions; and, (iv) the effects of full-scale drop-in fuel production on the GHG intensity of electricity across the United States.

Conclusions

Our results indicate that drop-in fuels could be initially scaled up within California since there are many

economic and employment benefits associated with producing fuel locally. However, the state will ultimately need to seek the participation of fuel producers in the Midwest and Southeast, where low-cost crop residues are more widely available and the grid is carbon intensive, enabling higher offset credits for exported electricity. The capacity for expanded biomass production in California is limited, in part because of the relatively high value of existing cropland. However, as noted earlier, woody biomass availability from forest management may be underestimated and warrants additional study. If current estimates are accurate, participation from Midwest and Southeast states is critical as California itself cannot adequately supply the feedstocks required to meet the 2030 goal. These biofuel producers are currently penalized under the state's Low Carbon Fuel Standard [33]. Additionally, further research is needed to expand the analysis beyond GHG emissions to include the full monetized impacts of air pollutant emissions and releases to soil and water.

Given our results, we have a number of recommendations for stakeholders, decision-makers, and researchers in fields relating to life-cycle assessment (LCA) of transportation fuels [34]. First, our scenarios demonstrate the importance of performing multiobjective analyses in transportation fuel LCAs, and particularly in considering the tradeoffs between costs and GHG emissions. For example, had we considered only GHG emissions, we would have deduced that methanol-to-gasoline and Fisher–Tropsch pathways were optimal since these fuels have the lowest normalized GHG emissions footprints. Ranking fuels based on their marginal abatement cost potentials is a more effective way of comparing competing technologies and strategies since truly sustainable policies must incorporate economic considerations. Second, lifecycle GHG emissions associated with transporting biomass and finished fuel are not a dominant contributor to overall emissions, and other location-specific factors (such as grid electricity offset credits) will prove more significant. Although we limited the scope of our analysis to the United States, it is possible that importing waste biomass resources or drop-in fuels from other counties (e.g., Mexico, China) could yield even greater GHG benefits, and marine transportation costs/emissions could potentially be low. Lastly, dropin fuels achieve very low emission factors when derived from biomass considered a waste. These factors may, in some cases, be overestimates if co-benefits of avoiding forest fires and on-farm burning are properly quantified. However, in some cases, the impacts on soil carbon may increase estimated emissions. Additional work is needed to better account for the net emissions associated with using different types of biomass residues and the impact of increased demand on the delivered costs.

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