California Policy Should Distinguish Biofuels by Differential Global Warming Effects

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ABSTRACT

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Biofuels such as ethanol offer potential greenhouse gas (GHG) reductions compared to petroleum-based liquid fuels. However, while the combustion of biomass is considered carbon neutral, the production of biofuels can result in considerable GHG emissions. These emissions are highly variable and determined by a range of factors such as agronomic practices (for energy crops), conversion technology, and fuel choice.

The state of California recognizes the potential for biofuels to reduce GHG emissions from the transport sector, yet state policies treat each type of biofuel as homogenous. Maximizing the climate benefits of biofuels will require life-cycle assessment (LCA) of all biofuel production pathways and regulations or incentives based on the differential global warming effects of each pathway. Certifying fuels requires monitoring and tracking the global warming intensity of each phase of production, for each pathway. Emissions for the agricultural phase of crop-based pathways, however, are highly site-specific; measuring and monitoring these specifics may not be worth the significant effort required. Instead, average values based on feedstock and region can be used to compute agricultural phase GHG emissions. In contrast, biorefineries, which are relatively few in number and far less complex, should be monitored individually.

Once each pathway has been analyzed, the net GHG reductions from large-scale biofuel use can be estimated. However, existing life-cycle analyses of the GHG emissions from biofuels production are inadequate and methodologically flawed. These analyses ignore complex market dynamics such as feedbacks (e.g. increased fuel use due to lower prices) and thresholds (e.g. saturation of coproduct markets) that occur at non-marginal production levels. Existing analyses also implicitly assume a "zero GHG" baseline, attributing all GHG emissions from crop-based biofuel production to the biofuel as if no emissions would occur absent biofuel production.

A second generation GHG accounting model is proposed to correct these flaws, integrating market equilibrium analysis with life-cycle assessment to produce better estimates of the GHG reductions attributable to each biofuel pathway under a realistic (i.e. non-marginal) production scenario. The improved model lays the groundwork for regulations and incentives to encourage greater GHG reduction benefits from biofuels, and perhaps to deny incentives for pathways yielding zero or negative benefits.

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Abbreviations Used

ASTM	American Society for Testing and Materials
CARB	California Air Resources Board
CARFG	California Reformulated Gasoline
CEC	California Energy Commission
CFC	Chlorofluorocarbon
CSP	Conservation Security Program
DDGS	Dried Distillers Grains with Solubles
E10, E85	Fuel with 10% (E10) or 85% (E85) denatured ethanol
EBAMM	ERG Biomass Analysis Meta Model
EOR	Enhanced Oil Recovery
EPACT2005	US Energy Policy Act of 2005
EtOH	Ethanol
FAF	Fuel adjustment factor
FFV	Flex-fuel vehicle
GHG	Greenhouse gas
GREET	Greenhouse gas, Regulated Emissions and Energy Use in Transportation (well-to-wheels LCA model)
GWI	Global warming intensity
GWP	Global warming potential
IAM	Integrated Assessment Model
LCA	Life-cycle analysis
MC	Marginal cost
Mgpy	Million gallons per year
MSW	Municipal solid waste
MTBE	Methyl-tertiary butyl ether
RFG	Reformulated Gasoline
RFS	Renewable fuel standard
USDA	US Department of Agriculture
WDG	Wet Distillers Grains

1. Introduction

Ethanol production capacity in the United States has more than doubled since 2001 and is expected to double again within a few years. As of June 2006, installed capacity is just over 4.8 billion gallons per year, with another 2.2 billion gallons per year of capacity currently under construction (Ethanol Renewable Fuel Association 2006).

The US federal government has promoted biofuels as a means of reducing petroleum imports. Indeed, life-cycle assessments (LCAs) show that ethanol production uses very little petroleum, regardless of the production pathway (Farrell, Plevin et al. 2006; Wang 2006). Substituting ethanol for gasoline is thus a viable strategy for reducing petroleum demand. In addition to reducing petroleum use, ethanol offers potential reductions in transport sector greenhouse gas (GHG) emissions. However, the magnitude of the climate benefits—and even the sign, in some cases—is highly dependent on the production pathway, i.e., choice of feedstock, agronomic practices, conversion technologies, and primary energy sources used.

Despite the range of pathway-dependent GHG benefits, US and California legislation treats ethanol largely as a homogenous product[1]. An alternative, as detailed in this study, is to measure, track, and regulate the life-cycle global warming intensity (GWI) of each production pathway, and to provide incentives to produce lower-GWI biofuels while discouraging high-GWI pathways. Accounting for the differential GHG impacts of different pathways is essential to assessing our progress toward mandated GHG reduction targets, although process- and market-based LCA boundaries would need to be reconciled with geographic boundaries.

More rigorous GHG accounting could also improve the implementation of the Pavley bill (AB 1493), which credits automakers with emissions reductions for demonstrated use of alternative fuels. As detailed below, the current methodology neglects the wide variance in GHG emissions from different pathways. As argued below, measuring and regulating biofuel GHG emissions would permit proper crediting of emissions reductions under AB 1493.

This paper examines the role for biofuels in California's climate protection strategy, with a focus on existing and proposed biofuels-related regulations. Many of the issues with pathway dependence described herein are shared by biogas, hydrogen, biodiesel, and Fischer-Tropsch diesel production, all of which may be derived from biogenic sources. This paper focuses on fuel ethanol.

The paper is structured as follows:

- Section 2 briefly reviews the national and state context in which biofuels are being promoted and summarizes recent California legislation and executive orders pertaining to biofuels, highlighting some of the outstanding issues.
- Section 3 examines a sampling of pathways available for ethanol production, illustrating the wide range of possible GWIs and showing why unregulated market forces will not ensure strong GHG reduction benefits.

[1] The Energy Policy Act of 2005 does provide special incentives for cellulosic ethanol, however, as defined, this category includes ethanol from both biogenic and fossil (waste) sources such as tires and plastics.

- Section 4 explores a number of methodological issues relating to the estimation of life-cycle GHG emissions from biofuels, building a case for a second-generation modeling effort that integrates market equilibrium analysis and more traditional LCA.
- Section 5 examines theoretical and practical approaches to regulating the GWI of biofuels.
- Section 6 proposes a second-generation modeling approach for evaluating the GWI of biofuels based on integrating market equilibrium analysis with LCA.
- Section 7 summarizes the key findings of this study and suggests further research directions.
- Appendix A examines whether regulating the GWI of biofuels merely reshuffles the market.

2. Context

2.1. US Context

The Energy Policy Act of 2005 (EPACT 2005) includes several provisions supporting "renewable fuels". Under EPACT 2005 "renewable fuels" as liquid and gaseous fuels derived from waste or biomass that are "used to replace or reduce the quantity of fossil fuel present in a fuel mixture used to operate a motor vehicle" (United States Congress 2005). Cellulosic ethanol is singled out in EPACT 2005 for additional incentives for production and for research and development. At the federal level, biofuels are portrayed primarily as a means to reduce petroleum imports. EPACT 2005, and much of the national political discourse, ignores the potential role of biofuels in reducing GHG emissions and thus also ignores the differential climate impacts of competing biofuel production pathways.

The singular focus on production levels rather than production processes virtually guarantees suboptimal environmental performance. Due mainly to the externalized environmental costs of energy consumption and nitrogen fertilizer use, the lowest private cost methods can be the most GHG-intensive. Emblematic of this problem is the increased use by new dry-mill corn ethanol facilities of coal rather than natural gas to raise process steam (Kirkbride McElroy, Jessen et al. 2006; Nilles 2006). Using coal instead of natural gas in a corn ethanol dry-mill facility can increase life-cycle GHG emissions by approximately 30% per unit of ethanol.[2]

2.2. California Context

In June 2005, Governor Schwarzenegger signed Executive Order S-3-05, setting aggressive GHG reduction targets for California: 2000 emission levels by 2010, 1990 levels by 2020, and 80% below 1990 levels by 2050 (Schwarzenegger 2005). The transportation sector is responsible for about 40% of the state's greenhouse gas (GHG) emissions (CalEPA 2006). Clearly, sharp reductions in automotive emissions are essential to meeting the state's emissions targets, requiring both improved fuel economy and a switch to fuels with low life-cycle GHG emissions, referred to herein as low global warming intensity (low-GWI) fuels. To meet this challenge, the California Air Resources Board (CARB) adopted regulations in 2005 under AB 1493 (Pavley,

[2] Calculated using the ERG Biofuels Analysis Meta-Model (EBAMM) and cross-checked in GREET 1.7. EBAMM is the *ERG Biofuels Analysis Meta-Model,* originally developed to compare a set of ethanol life-cycle analyses. The model and documentation are available for downloading at http://rael.berkeley.edu/EBAMM. GREET is available for download from Argonne National Laboratory at http://www.transportation.anl.gov/software/GREET/.

2002) establishing per-mile GHG emission limits for 2009 model year and later vehicles. These regulations are discussed in Section 2.3.1.

The replacement of banned oxygenate MTBE turned California into the nation's largest single ethanol market. In 2004, California used about 900 million gallons of fuel ethanol, almost all of which was produced from corn grown in mid-western states and imported to California (Bioenergy Interagency Working Group 2006). A recent executive order signed by the governor aims to bring more biofuel production into the state. The implications of this order are discussed in Section 2.3.4.

For the State of California, biofuels represent a significant opportunity to reduce GHG emissions from the transport sector. However, as EPACT fails to consider the GHG emissions of biofuels, the state will have to craft its own policies to ensure that the potential climate benefits of using biofuels are not squandered.

2.3. Biofuels-related Regulations and Proposals for California

Two recent bills and one executive order address the role of biofuels in California's transport sector: AB 1493 (Pavley, 2002), AB 1007 (Pavley, 2005), and Executive Order S-06-06 signed by Governor Schwarzenegger in April 2006. These are each examined below.

AB 1493

The 2002 Pavley law (AB 1493) and the related regulations adopted by CARB in 2005 establish GHG emissions limits for motor vehicles in California. The regulations are projected to result in fleet-wide GHG reductions of about 17% from 2009 and later model-year vehicles by 2016, and by about 27% by 2030. The emissions limits were determined by analyzing a wide range of automotive technologies to determine what combinations allow "the maximum feasible and cost-effective reduction of greenhouse gas emissions from motor vehicles" (CARB 2005). The limits are applied to each manufacturer by vehicle class (automobile, light-duty truck), weighted by sales volume per class. Manufacturers can trade GHG credits within their own two vehicle classes.

AB 1493 establishes GHG regulations accounting for fuel-cycle CO_2, N_2O, and CH_4, and life-cycle CFC emissions from vehicle air conditioning systems. The regulations, however, are defined in terms of tailpipe CO_2, using adjustment factors to account for the other emissions.

The regulation accommodates alternative fuel vehicles by adjusting the reported emissions for equivalent gasoline-fueled vehicles using a per-fuel constant. Table 1 shows the fuel adjustment factors for natural gas, LPG, and E85. The FAF for E85 of 0.74 results from the assumption that E85 reduces GHG emissions 23% relative to gasoline, based on analysis by TIAX using the GREET model[3] and assuming 100% corn-based ethanol (Unnasch 2006). The use of a single value for each fuel ignores differences in GWI for different fuel pathways, thus incentives for low-GWI pathways are lost.

[3] The Greenhouse-gas, Regulated Emissions and Energy Use in Transportation (GREET) Model is an Excel™-based "well-to-wheels" life-cycle analysis model developed by Michael Wang at Argonne National Laboratory. It is available for download at http://www.transportation.anl.gov/software/GREET/.

Table 1. Fuel Adjustment Factors defined by AB 1493

Fuel	Adjustment Factor
Natural Gas	1.03
LPG	0.89
E85	0.74

The regulations permit credit for bi-fuel and flex-fuel vehicles to fleets that can be shown to "achieve GHG reductions through documented increased use of alternative fuels in eligible vehicles" (CARB 2005).

Issues with AB 1493

As the purpose of AB 1493 is to maximize cost-effective GHG reductions, the state should provide automakers greater credit for documented use of low-GWI biofuels, such as cellulosic ethanol instead of higher-GWI biofuels such as corn ethanol. The regulations, as currently written, do not provide such credit, but rather use a single per-fuel adjustment factor. The *Final Statement of Reasons*, which documents the procedures adopted for AB 1493, describes the rationale for the Fuel Adjustment Factor (FAF) as follows:

> To maintain simplicity, staff proposes to use the upstream emissions for vehicles that use conventional fuels as a "baseline" against which to compare the relative merits of alternative fuel vehicles. Therefore, the emissions standards as shown above do not directly reflect upstream emissions. Rather, when certifying gasoline or diesel-fuel vehicles manufacturers would report only the "direct" or, "on vehicle" emissions. For alternative fuel vehicles, exhaust CO_2 emissions values will be adjusted in order to compensate for the differences in upstream emissions. *This approach simplifies the regulatory treatment of gasoline vehicles, while at the same time allowing for appropriate treatment of alternative fuel vehicles.* (CARB 2005) [Emphasis added.]

While surely simplifying regulatory treatment, the appropriateness is doubtful. The use of a single adjustment factor for each broad fuel category assumes (a) homogenous GWI impacts from all production pathways for each alternative fuel, (b) a consistent composition of the alternative fuel as combusted, and (c) a constant fossil-fuel baseline to which the adjustment factor is applied. Unfortunately, none of these assumptions holds, at least for ethanol: (a) is generally untrue for the life-cycle analysis of *any* fuel, (b) is untrue due to the variable definition of E85 (described further below), and (c) will be increasingly violated given the near-term decline of conventional oil and the likely increased production of high-GWI synthetic petroleum (Brandt and Farrell 2005).

Variability in the Composition of Ethanol-Gasoline Blends

Pure ethanol (hereafter EtOH) is denatured by adding up to 5% by volume of a toxic substance (generally gasoline) to avoid taxation as beverage alcohol. The ASTM standard indicates that denatured ethanol can contain as little as 92.1% EtOH. In the US, denatured ethanol is generally 95% EtOH, 5% gasoline.

E85 is generally defined as containing 85% "ethanol" and 15% gasoline by volume. In fact, it is nominally 85% *denatured* ethanol (also termed "fuel ethanol"), or about 81% EtOH, 19% gasoline. (85% x 95% = 80.75%). However, in winter, the percentage by volume of EtOH in E85 drops to 70%, though it is still labeled and sold as E85 (NREL 2002). Table 2 shows that the minimum percentage by volume of EtOH in E85 varies from 70-79%.

Table 2. ASTM D5798-99 Standard Specification for Fuel Ethanol for Automotive Spark-Ignition Engines

ASTM volatility classes are defined relative to temperature and season, with Class 1 being a warm weather blend, and Class 3 being a cold weather blend. California has a few class 3 areas in the southeast in the winter. Source: (NREL 2002). In this table, "ethanol" means pure EtOH.

Property	Value for Class		
ASTM volatility class	1	2	3
Ethanol, plus higher alcohols (min. vol. %)	79	74	70
Hydrocarbons (incl. denaturant, vol. %)	17-21	17-26	17-30

Variability in Gasoline Baseline

The proposal by the CA Air Resources Board to implement AB 1493 says "To maintain simplicity, staff proposes to use the upstream emissions fraction of conventional fuels as a "baseline" against which to compare the relative merits of alternative fuel vehicles." This approach presupposes a constant, homogenous baseline. The baseline, however, will not remain constant if oil depletion and national security concerns drive the increased development of unconventional petroleum sources such as tar sands, oil shale, and coal-to-liquids—all of which have much higher upstream GHG emissions than conventional petroleum. Nor does this approach appear to consider that CA oil has a higher GWI than average due to the wide use of thermal enhanced oil recovery (EOR) in the state (CEC 1999)[4]. CARB regulations do not indicate whether the gasoline baseline will be adjusted as petroleum becomes more GHG intensive, or whether this should simply require further automotive technology improvements, effectively penalizing automakers for changes in petroleum production.

The production of synthetic petroleum fuels based on coal, tar sands, and oil shale can emit more than double the upstream CO_2 emissions of fuels based on conventional petroleum (Brandt and Farrell 2005). To manage transportation GHG emissions, the state will need to recognize this variability, and perhaps regulate the GHG emissions of all fuels. To do otherwise could result in the GHG reductions from biofuels being offset or surpassed by the GHG increases from synthetic petroleum fuels.

Recommendation for AB 1493

One way to address the variability that plagues the Fuel Adjustment Factor approach would be through a cap and trade system. The regulatory limit (cap) partitions producers into potential buyers and sellers, thereby creating a market. Such a system would require biorefineries or fuel blenders to use and document low-GWI pathways or to purchase credits from firms that are able to beat the regulatory levels. California would need to define default GWI ratings for untracked imported fuels and allow low-GWI producers to opt-in to tracking program thereby earning a premium from blenders. Assuming a binding cap, the regulated level would then accurately

[4] In 1995, the CA Energy Commission reported that 63% of California petroleum was produced using thermal EOR, and California thermal EOR accounted for more than 60% of the total EOR production in the US.

describe the average GWI for all ethanol used in the state, creating a market for low-GWI fuel, and allowing meaningful use of a single per-fuel FAF.

AB 1007

AB 1007 (Pavley, 2005) calls on the California Energy Commission and Air Resources Board to develop and adopt a state plan to diversify the transportation fuel supply. It also requires CARB to evaluate a range of alternative fuels on a life-cycle basis to compare their emissions of criteria pollutants, air toxics, GHGs, and water pollutants, their impacts on petroleum consumption, and anything else the state board decides should be considered (Pavley 2005).

The CARB study should consider the issues raised in this paper to improve their life-cycle accounting methodology.

Executive Order S-06-06

Executive Order S-06-06, signed in April 2006, mandates in-state "production" of increasing percentages of the state's biofuels consumption, where *production* implicitly means processing inputs regardless of their geographic origin. It sets targets of 20 percent in-state production of biofuels by 2010, 40 percent by 2020, and 75 percent by 2050. Given that cellulosic ethanol conversion technology remains pre-commercial, the 2010 target will most likely be met with sugar- and starch-based ethanol. The easiest way to meet this short-term goal will be to import corn from the Midwest for local processing, as planned by Pacific Ethanol for its plant under construction in Madera.

California consumed 900 million gallons of ethanol in 2004, of which 20% would be 180 million gallons per year. Nearly all gasoline in the state is E5.7, which contains 5.7% denatured ethanol[5] (Jones, Smith et al. 2005). The Energy Commission's base case projection of gasoline demand in 2010 is 17.2 billion gallons, increasing to 19.6 billion gallons in 2020 (CEC and CARB 2003). At the current 5.7% blending level, California's ethanol consumption would be 980 million gallons in 2010, of which 20%, or about 200 million gallons per year would be required to be produced in-state[6].

As of 2005, California produces about 40 million gallons per year of ethanol, with another 80 mgpy of capacity in construction. (Jones, Smith et al. 2005, p. 14). Thus, the 2010 target requires the in-state construction of about 80 million gallons per year of additional capacity, equivalent to one large or two moderately sized facilities. This seems readily achievable, and may well have been the case without S-06-06. However, if the state were to mandate the use of E10 (10% ethanol), the state's production would have to increase from 120 mgpy to nearly 350 mgpy.

Issues with S-06-06

The executive order does not create a renewable fuel standard (RFS) dictating an absolute quantity or percentage of biofuels in the state's liquid fuel mix. Rather, the order requires that increasing percentages of the biofuels used in the state must be produced in the state. This provides a much weaker signal to investors than would the combination of an RFS with an in-state production requirement, especially in light of the elimination of the oxygenate requirement.

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[5] Denatured ethanol usually contains 5% gasoline, so actual ethanol content would be 95% x 5.7% = 5.41%.
[6] There is only one public E85 pump in the state currently, so we disregard E85 volume in this analysis.

In the extreme case, this in-state percentage requirement could be met simply by reducing overall ethanol consumption without increasing in-state production.

Nor does the executive order have real teeth: it fails to hold any entity responsible for meeting the stated targets, nor does it indicate which agency should determine such responsibility. It does obligate the CEC, CARB, and the California Public Utilities Commission to includes these goals in their planning, but none of these entities has the authority to penalize, say, blenders or refineries for missing the targets.

Lastly, the executive order does not indicate a preference for low-GWI biofuels, and therefore offers no assurance that the use of biofuels will result in significant GHG emission reductions. Given the state's abundant cellulosic resources from agricultural residues, forestry, and municipal solid waste, it could reasonably be assumed that cellulosic ethanol will eventually dominate in-state production, and thus virtually ensure a significant reduction in GHG emissions relative to the use of petroleum fuels. However, the GHG emissions reduction from ethanol as determined by a market that places no value on those reductions is virtually certain to be weaker than could be achieved under regulation.

Although the state's Bioenergy Action Plan calls for two billion gallons of biofuels by 2020, it would be premature for the state to set specific RFS levels, as CARB is currently revising its Predictive Model, which is used to estimate emissions from various fuel blends (Jones, Smith et al. 2005). The tailpipe and evaporative emissions from ethanol-blended fuels vary with blend level, requiring adjustments to the Predictive Model before assessing impacts of the full range of blends that will occur when drivers of FFVs mix arbitrary quantities of gasoline with E85 in their tanks. RFS levels will also be informed by the results of the report required under AB 1007, which will evaluate the petroleum and GHG reduction benefits of various alternative fuels. This is slated for completion by June 30, 2007.

3. Estimating the Greenhouse Gas Emissions from Biofuels

The carbon released as CO_2 by combustion of biofuels was absorbed from atmospheric CO_2 during feedstock growth. The net CO_2 emissions from the *combustion* of biofuels are thus considered to be zero. The life-cycle global warming contribution of any biofuel is therefore determined by the GHGs emitted during the production or collection of the feedstock and its conversion to a liquid fuel. While biofuels have the potential to have low GWI, a wide range of upstream GHG emissions is possible, depending on feedstock, agronomic choices, conversion pathways, and primary energy sources employed. This section outlines the major feedstocks and pathways.

3.1. Energy Crops

Corn

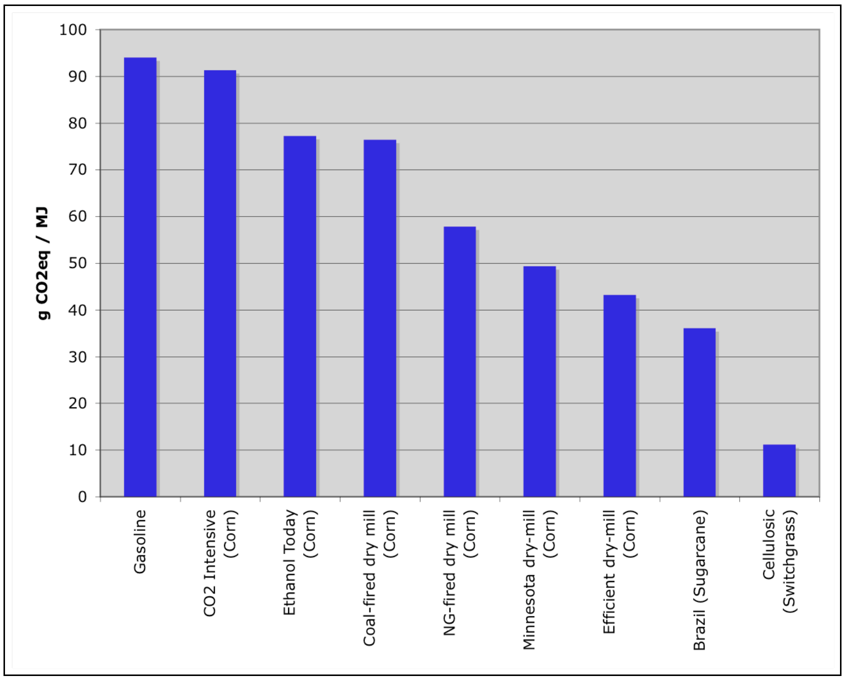
Over 90% of the ethanol used in California in 2004 was produced from corn and imported from the Midwest (Bioenergy Interagency Working Group 2006). In-state ethanol production is due to increase in Q4 2006 when Pacific Ethanol's 35 million gallon per year corn ethanol plant comes on-line. The plant will produce ethanol from imported Midwest corn, selling the coproduced wet distillers grains[7] to local dairy producers and the CO_2 resulting from fermentation to the food and beverage industry (Pacific Ethanol Inc. 2006).

A recent study of average corn-based ethanol in the US indicates a life-cycle GHG savings of 18% versus gasoline, however there is significant uncertainty, which ranges from a 36% reduction to a 29% increase versus gasoline (Farrell, Plevin et al. 2006). This estimate, however, is an average based on an industry survey from 2001. More than half of the current US ethanol production capacity has come on-line since that survey, so the older, less efficient stock of biorefineries are over-represented in that analysis. The percentage of more efficient dry-mill facilities is increasing rapidly, resulting generally in a reduction in the industry average energy use and GHG emissions. However, several new dry-mill plants are planning to use coal rather than natural gas to raise steam due to the rising cost of natural gas. According to modeling done in EBAMM, ethanol from average corn processed in a natural-gas-fired dry mill plant results in life-cycle emissions of 59 g CO_2eq per MJ of ethanol, a 37% reduction in GHG emissions compared to conventional gasoline. Substituting coal for natural gas in the dry mill increases life-cycle GHG emissions to 78 g CO_2eq/MJ. At this level, the newest coal-fired dry mill plants produce ethanol with essentially the same GWI as the industry average, which we calculate at 77 g CO_2eq/MJ. In other words, switching from natural gas to coal erases recent progress toward greater GHG benefits, and the benefits were not very certain to begin with.

[7] Corn ethanol produced in dry-mill facilities coproduce “distillers grains”—the protein- and fiber-rich residue that remains after fermenting the starch fraction of the corn kernels to produce ethanol. To reduce shipping costs and increase shelf-life, ethanol facilities typically dry their distillers grains. This energy intensive process can be avoided when there is a local market for the wet distillers grains (WDG), as in the Pacific Ethanol case.

Figure 1. Differential Life-cycle GWI of Ethanol Pathways and Gasoline.

Gasoline is shown for reference. The *CO_2 Intensive* case assumes Nebraska corn is shipped to South Dakota for conversion to ethanol in a coal-fired dry-mill. *Ethanol Today* describes a statistical average corn ethanol production pathway as of 2001, including both wet- and dry-mill facilities. The *Coal-fired* and *NG-fired* dry mills are based on *Ethanol Today* using only a dry-mill plant, with all process energy provided by coal or natural gas, respectively. The *Minnesota Dry-mill* case uses data provided by a 1996-era plant in southern Minnesota. The *Efficient Dry-mill* case is based on estimates by the Minnesota plant manager of the efficiency of the company's best technology, which is currently in use in twelve plants. In all cases, average corn-belt maize is assumed, as modeled in *Ethanol Today*. Combustion phase emissions are included only for gasoline; combustion phase carbon from biofuels is considered climate neutral. Ethanol values were computed in EBAMM. Gasoline value is from GREET 1.6.



Other corn ethanol facilities are doing far better than average. For example, a natural gas-fired facility in Minnesota uses a 1996 design that produces ethanol (assuming average corn) with 50 g CO_2eq/MJ. More recent facilities utilizing a "no-cook "design come in even lower at 43 g CO_2eq/MJ, based on preliminary data modeled in EBAMM.

Another example is the E3 Biofuels facility in Nebraska, which is integrated with a feedlot, allowing distillers grains to be delivered wet, avoiding approximately 50% of a typical dry mill's thermal energy requirement. Instead of natural gas, the facility is powered by biogas generated in two 40 million gallon anaerobic digesters that process all manure from the feedlot as well as the thin stillage (the liquid remaining after centrifuging the distillers grains). Given that this system also produces beef, it isn't directly comparable to a standard dry mill, but given the avoided methane emissions from eliminating the manure lagoon, plus the reduced energy consumption, this system clearly has a much lower global warming impact. Modeling in EBAMM shows that a 2001-era gas-fired dry-mill coproducing only wet-cake (eliminating half of its natural gas consumption) would emit 43 g CO_2e/MJ, which is equal to the GHG emissions from an Efficient Dry-mill coproducing dried distillers grains. Obviously a modern, efficient dry-mill eliminating its gas consumption for drying would do even better, but we lack the data on how much gas would be avoided in this type of facility.

Several US dry-mills are exploring or deploying innovative alternatives to natural gas, including gasifying or combusting wood waste, distillers grains, and corn stover, or using advanced cogeneration units (Nilles 2006). Others are locating near cattle feedlots to sell wet distillers grains, halving a typical plant's natural gas consumption. The challenge for policy-makers is to ensure that these more beneficial configurations and energy sources are favored over using coal.

Switchgrass

The *Cellulosic* case modeled in EBAMM shows that using switchgrass-based ethanol in place of conventional gasoline reduces GHG emissions about 88%. However, unlike modeling corn-based ethanol, which is based on USDA statistics, industry surveys, and decades of actual production, the *Cellulosic* case is necessarily hypothetical as no commercial-scale facilities are yet in operation.[8]

In the biochemical pathway modeled in GREET, the combustion of the unfermentable fraction of the plant material (lignin) for process heat and electricity results in a coproduct energy credit of approximately 16% of the total input energy. This credit is due to displacement of fossil sources otherwise used to produce electricity. As discussed below in Section 3, the credit for avoided electricity production is sensitive to the mix of power plants in the regional grid, and to whether an average grid mix or the marginal plant is used to determine avoided GHG emissions.

Switchgrass is considered unlikely to be grown as an energy crop in California (Walsh, de la Torre Ugarte et al. 2003). The natural range for this native prairie grass extends across the eastern two-thirds of the lower 48 states.

Short-rotation Woody Crops

Several life cycle analyses of biomass-based electricity using poplar and willow feedstocks have been developed (Mann and Spath 1997; Heller, Keoleian et al. 2003; Spitzley and Keoleian 2005). The results reported for the agricultural phase could be combined with assumptions from GREET about the conversion of woody cellulose to ethanol to determine the range of life cycle GHG benefits available under different agronomic choices. Such an analysis, however, is beyond the scope of this paper.

Dedicated energy crops are not yet produced on a commercial scale in California, but several species are under consideration in part for remediation of waterlogged or salt-damaged soils, especially in the San Joaquin Valley. (California Biomass Collaborative 2005).

3.2. Residues and Wastes

California has significant cellulosic residue and waste resources that can be converted to ethanol. According to a 2005 study, the state produces 86 million bone-dry tons (BDT) of biomass annually, of which about 34 million BDT is technically available on a sustainable basis for conversion to energy. The amount of economically viable resources would be lower. Figure 2

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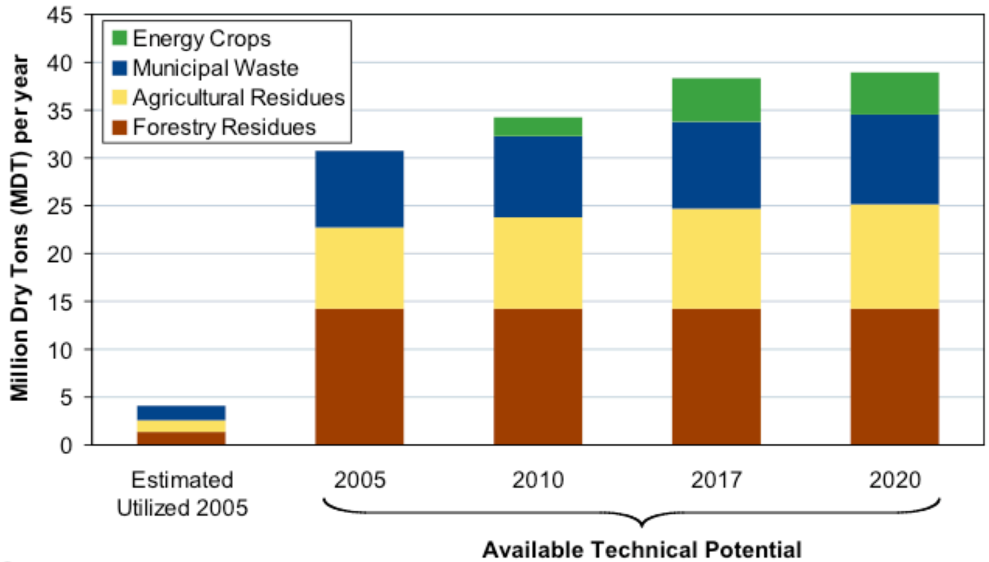
[8] For example, GREET 1.5 (the latest version for which documentation is available) bases its cellulosic ethanol plant performance assumptions on simulations done by the National Renewable Energy Laboratory in 1991 and 1998.

shows projected availability of biomass resources from energy crops, municipal waste, agricultural residues and forestry residues.

Figure 2. Solid Biomass Utilization and Technical Potential in California.

(Source: Bioenergy Interagency Working Group 2006)



Sources:

California Energy Commission, November 2005, *Draft Report An Assessment of Biomass Resources in California, 2005*, California Energy Commission, Sacramento, CA., Contract number 500-01-016. (Table 4.1)

California Energy Commission, April 2005, *Biomass in California, Challenges, Opportunities and Potential for Sustainable Management and Development*, California Energy Commission, Sacramento, CA., Contract number 500-01-016.

Energy crops are projected to comprise a small fraction (around 15%) of the total biomass resource. (Although they may be a larger fraction of the economically viable resource.) The inclusion of feedstocks other than purpose-grown energy crops raises several methodological issues for the life cycle analysis, which are covered in detail in Section 4.

Agricultural Residues

As illustrated in Figure 2, above, agricultural residues comprise a significant fraction of the state's biomass resource base. It's important to note that agricultural residues are generally not "waste". The international standard for LCA (ISO 14040) defines waste as "substances or objects which the holder intends or is required to dispose of" (ISO 2006). When left in the field, however, residues contribute to soil fertility, provide erosion control, and reduce soil drying. Removal of these resources imposes costs, both environmental and quite possibly financial. Residue resource analyses typically consider the maximum removal rate that won't impair these environmental functions, although the permissible level of removal is dependent on yield, soil characteristics, climate, and agronomic practices (Sheehan, Aden et al. 2003; Wilhelm, Johnson et al. 2004).

Residues from corn (stover) or other energy crops are easily accommodated in the existing life cycle frameworks, as these residues share the same agronomic system. Once used as an ethanol feedstock, they are accounted for in the same manner as, say, corn kernels in the life cycle accounting.

Analysis of residues from non-energy crops, however, requires a full life-cycle accounting of the crop with an allocation of inputs and effluents (including GHGs) between the main cash crop and the residues used as ethanol feedstock.

Municipal Solid Waste

Although much of the discussion about ethanol centers on agricultural sources, one of the largest, readily available feedstock sources in California is municipal solid waste (MSW). The state generates 38 million tons per year of construction and demolition wood residue, paper and cardboard, grass, landscape tree removals, other green waste, food waste, and other organics, about half of which is landfilled; the other half is recycled, composted, or otherwise diverted from landfills (California Biomass Collaborative 2005). This total does not include plastics or tires, which can also be converted to ethanol, potentially reducing petroleum demand, although with minimal GHG benefits, i.e. from the avoided upstream emissions for gasoline not produced.

California landfills recover between 59 and 78 billion cubic feet per year[9] of methane equivalent landfill gas, with collection occurring at about 300 of the 3,000 waste disposal sites in the state (California Biomass Collaborative 2005). The 19 million tons of the state's MSW that is landfilled annually could theoretically generate 950 million gallons of ethanol per year, assuming the performance claimed by both BRI Energy and BioConversion Technology, i.e. 50 gallons of ethanol from a ton of municipal solid waste (BioConversion Technologies 2006; BRI Energy 2006). These performance figures are taken from the two firms' marketing literature, but even discounting these figures substantially, it's clear that the MSW-to-ethanol potential for the state is quite large, potentially meeting a significant fraction of the state's current ethanol usage.

Besides this annual flow of MSW, there is an estimated stock of 1 billion tons (as received, wet tons) of waste in-place at the state's 3,000 disposal sites. It may be possible to mine existing landfills for biomass. Converting this biomass resource to ethanol would provide double climate benefits by both reducing fugitive methane emissions and displacing petroleum consumption. Landfilled MSW is the single largest source of anthropogenic methane emissions in the US, accounting for 34% of the total, or about 55 million tons carbon equivalent in 2001 (US EPA 2006). About 60 percent of landfill gas is emitted at sites without gas capture systems, and even at sites with such systems, 25% of the landfill gas escapes to the atmosphere (Chen and Greene 2003).

3.3. Imported Ethanol

In 2005, the US edged past Brazil as the world's top producer of ethanol, producing 4,264 million gallons to Brazil's 4,227 million gallons. Third place China produced 1,004 million gallons. These three nations together accounted for 78% of the 12 billion gallons of ethanol produced globally in 2005 (Ethanol RFA 2006). About 10 percent of the ethanol used in California arrives by ship from Caribbean Basin Initiative countries and from Brazil. All of this imported ethanol is produced from sugar cane (Jones, Smith et al. 2005).

Brazilian sugarcane ethanol production is very efficient, owing to (a) a high yield (80 tonnes per hectare), (b) the use of bagasse (sugarcane residues) for process energy, and (c) a high reliance

[9] For comparison, the state uses about 2,200 BCF/y of natural gas (California Biomass Collaborative 2005).

on human labor compared to US farming, with correspondingly lower liquid fuel use (Dias De Oliveira, Vaughan et al. 2005). Preliminary analysis of Brazilian sugarcane in EBAMM indicates a low GWI of 36 g CO_2eq/MJ—less than half the life-cycle GHGs from US average corn ethanol—and the current average value may be yet lower as this estimate is based on production data that are at least ten years old. Even accounting for shipping to the US, Brazilian ethanol offers greater GHG benefits than most domestically produced corn ethanol.

The US imported about 126 million gallons of ethanol in 2005, amounting to just over 3% of total ethanol consumption.[10] More ethanol would be imported from Brazil were it not for the 2.5% *ad valorum* tax plus the $0.54 per gallon import tariff applied to ethanol. The tariff is added to offset the federal tax credit given to US blenders for each gallon of ethanol.[11] Caribbean nations can export various quantities to the US with reduced or no tariffs depending on the percentage local content. However, the volume of duty-free imports from the Caribbean is capped at 7% of US ethanol consumption (Severinghaus 2005).

When measuring the GHG reductions of imported ethanol, we must consider the potential role of biofuel development in inducing tropical deforestation, as this could cancel the GHG reductions from gasoline displacement, or worse, result in net GHG emissions. This issue has received some attention in Europe, where researchers have been studying the use of certification and labeling systems to ensure sustainable production of biofuels (Bauen, Howes et al. 2005; Lewandowski and Faaij 2006). This issue is addressed further in Section 4.

4. Methodological Issues in the Estimation of Climate Benefits from Biofuels

This section outlines several important methodological issues with existing life-cycle analyses of biofuels. The solution to the issues raised below is to integrate market impacts with life-cycle analysis. Section 6 outlines a "second generation" LCA model and how it could be used to understand and regulate the GHG emissions from biofuels.

4.1. Missing Markets

Life-cycle analysis, as defined in ISO 14040, ignores prices (ISO 2006). The omission of prices and markets "introduces an error of unknown but potentially large magnitude, and thereby may render the results of conventional LCAs meaningless" (Delucchi 2005). Moreover, standard LCA asks a policy-irrelevant question: *What happens if we simply replace one limited set of activities with another?* This is irrelevant because direct substitution rarely (if ever) occurs; rather, substitution is generally partial, and is mediated by complex market and policy linkages with many indirect effects. In the non-marginal case, the climate impacts due to coproducts may be non-trivial. Analyzing the chain of impacts requires an economic equilibrium analysis (Delucchi 2005).

[10] Net imports were 125.6 million gallons. Imports were 133.6 million gallons, and exports totaled 8 million gallons. Source: http://www.ethanolrfa.org/industry/statistics/

[11] This offset supports the interpretation of the subsidy as a favor to US ethanol producers rather than an environmental policy.

To understand the potential environmental consequences of biofuel use, a more pertinent question would be: *What is the net impact of a given policy choice (e.g. developing biofuels) versus some baseline?* Delucchi (2005) writes:

> It is conceptually impossible to evaluate a fuel such as ethanol "by itself;" rather we must estimate the difference between doing one thing rather than another. These differences between alternative worlds are a function of the initial conditions in each world, the initial perturbations (or changes), and dynamic economic, political, social, and physical forces.

Considering an LCA of a product in isolation implicitly compares the production process to the "zero option", which is equivalent to assuming that if the product is not created, all of the impacts associated with its production would be avoided (Kaltschmitt, Reinhardt et al. 1997). This assumption is surely incorrect for corn-based ethanol. According to an economic equilibrium model by the Food and Agricultural Policy Research Institute at the University of Missouri, the expansion of ethanol production to meet the requirements of EPACT will result in a decrease in both soybean acreage and corn exports, with only a small amount of unfarmed land shifting into production (FAPRI 2006). Thus, corn would have been produced on much of the land in any case, and other crops (with varying GHG emissions) would have been produced on other portions of the land. Considering this non-zero baseline likely reduces significantly the GHG emissions attributable to the agricultural phase of corn ethanol production.[12] Life-cycle analyses of biofuels performed to date fail to consider these secondary market-mediated effects.

A dynamic relationship exists among the markets for gasoline, ethanol, E85, and flex-fuel vehicles. The effects of the increased supply of ethanol on fuel markets depend on whether ethanol functions as an additive or as a fuel. For example, the substitution of 5.7% ethanol for 11% MTBE results in a "volume gap" which increases gasoline demand (*ceteris paribus*), while decreasing demand for natural gas, from which MTBE is produced.[13] However, when ethanol enters the market as a fuel in the form of E85, it adds to the supply of liquid fuels in the local E85 market surrounding each fueling station. Demand is constrained by the number of local FFVs—although some non-FFV owners use E85 regardless. If offered at a low enough price, most FFVs in the area would switch to E85 (assuming sufficient supply), but above some price threshold, few would use it. Eventually, enough FFVs and E85 stations may exist to link together the current patchwork into a single market, although some states offer additional subsidies beyond the federal tax credit.

4.2. Choice of Baseline

To analyze the GHG reduction potential from ethanol, each pathway must be compared to some baseline. The EBAMM model compares the grams of life-cycle CO_2-equivalent emissions from ethanol production to those of conventional gasoline production. In retrospect, this does not

[12] Consideration of the "displaced" agricultural coproducts, e.g. soybeans for animal protein, accounts for the portion of the baseline attributable to coproducts, but it doesn't account for the starch fraction that becomes ethanol. A complete analysis would need to consider induced land-use abroad due to reductions in corn exports from the US.

[13] An alternative interpretation offered by Tom MacDonald of CEC is that if the oxygenate waiver sought by California (now included in EPACT2005) had been granted at the time MTBE was phased out in the state, the baseline would have been 100% CARFG without oxygenate. From this perspective, the addition of 5.7% ethanol can be viewed as displacing gasoline, however it's unclear whether any ethanol would have been used under these circumstances. (Personal communication, 8/21/2006)

properly capture the net change for various reasons, depending on whether the marginal ethanol is used in low blends as an additive or in high blends as a fuel.

Ethanol as Additive

Virtually all fuel ethanol used in the US today is blended with gasoline at low levels. In most cases, ethanol serves as a replacement for MTBE, which has been banned for polluting groundwater. Although EPACT2005 removed the oxygenate requirement, using ethanol is the easiest way for refiners to meet octane requirements, and since ethanol burns more cleanly than most petroleum components, it also helps refiners meet fuel emissions requirements (EIA 2006). Thus, in the current market, with very limited sales of E85, a more basis for calculating the GHG reductions from ethanol would assume that ethanol substitutes for MTBE. However, a direct comparison between these two substances is insufficient: ethanol contains more oxygen by volume than MTBE, so a 5.7% ethanol blend provides the same oxygenation as an 11% MTBE blend. An appropriate comparison would be California reformulated gasoline (CARFG) with 11% MTBE versus CARFG with 5.7% ethanol, compared on an energetically equivalent basis.

It turns out that using CARFG with 11% MTBE results in nearly identical GHG emissions to conventional gasoline (94 g CO_2-eq per MJ), so the commonly-used comparison to conventional gasoline is reasonable—at least for the portion of ethanol used at low blends—although for the wrong reason.

Ethanol as Fuel

In 2005, 16.4 million gallons[14] of ethanol were consumed in E85 in the US (Energy Information Administration 2006). This represents merely 0.4% of the 3.9 billion gallons of ethanol produced domestically that year. When used in higher-percentage blends, ethanol doesn't directly substitute for gasoline, but rather the production of E85 increases the supply of liquid fuels for a segment of the market. This may result in a decline in the price of gasoline, which in turn may induce more consumption. The point is that the substitution is not necessarily 100% but is dictated by the market. For E85 to serve as a gasoline substitute requires (a) flex fuel vehicles, (b) access to E85, (c) that drivers know the E85 option is available (in their vehicle and at the pump), and (d) that drivers have the inclination to use E85 despite its often higher price on an energetic basis. At present, these conditions obtain more frequently in the Cornbelt than in California.

US automakers have pledged to double the annual production of flex-fuel vehicles to 2 million by 2010 (Thomas 2006), and several states have announced plans to increase access to E85 in fueling stations. If E85 were introduced in California today, it would not substitute for MTBE, but for CARFG—which itself currently contains 5.7% ethanol. When computing the GHG emission reductions for using E85 in California, we should compare this fuel blend on an energetic-equivalent basis to CARFG as presently formulated—or to what we assume would be sold at that time under a business-as-usual scenario.

[14] Downloadable data associated with the EIA's 2006 Annual Energy Outlook reports 0.00125 QBtu of ethanol was used in E85. The published report shows this as 0.00.

Table 3. Comparison of MTBE and corn ethanol using EBAMM *Ethanol Today* and *Cellulosic* cases

	MTBE	Ethanol Today	Cellulosic
Energy content (LHV, MJ/L)	26	21	21
GHGs (g $_{CO2}$-eq/MJ)	93	77	11

Table 4. Comparison of CARFG blended with MTBE versus corn ethanol using *Ethanol Today* and *Cellulosic* cases

	CARFG + MTBE	CARFG + Ethanol Today	CARFG + Cellulosic
Energy content (LHV, MJ/L)	31.2	31.2	31.2
Oxygenate blend level in CARFG	11%	5.4%	5.4%
GHGs (g CO_2-eq/MJ)	94	93	90

Based on GREET 1.7 and EBAMM spreadsheets

Tables 3 and 4 show the energy content and life-cycle GHGs associated with MTBE, Ethanol (as per the EBAMM *Ethanol Today* case), and CARFG with MTBE and with ethanol. Note that CARFG has the same energy density whether blended with 11% MTBE or 5.4% ethanol, so users experience no energy penalty for using ethanol at this blend level. At the 5.4% blend level, the lower GHG emissions from ethanol have little effect on the emissions of the blended fuel. Even using the low-GWI *Cellulosic* ethanol case from EBAMM, estimated at just 11 g CO_2-eq/MJ, the resulting CARFG blend measures 90 g CO_2-eq/MJ, a 4% reduction versus CARFG with 11% MTBE.

Low-GWI Imports

Another challenge related to the determination of a baseline relates to low-cost imported ethanol. Brazilian sugarcane ethanol is produced at lower cost and with lower GHG emissions than corn ethanol. If the US were to reduce or eliminate the $0.54 per gallon import tariff on Brazilian ethanol, and more ethanol were imported, this lower-GWI ethanol could displace either petroleum or higher-priced corn ethanol—or some of both. The greenhouse gas benefits of the imported ethanol, again, are a function of market dynamics.

In summary, the net benefits of ethanol use are a function of the choice of baseline and of market response to the introduction of the fuel. Life-cycle analyses that assume that every MJ of ethanol will displace a MJ of gasoline are incorrect, although the size of the error is unclear.

4.3. Comparing Disparate Pathways

One requirement of a GHG accounting system for biofuels is that the analytic framework be consistent across pathways. To do otherwise would create a bias toward some fuel pathways. Expanding the biofuels life-cycle analysis to include waste-based pathways highlights additional problems with the analytic approach typically used for crop-based pathways.

Most crop-based LCAs treat all emissions from the studied process as additional. These studies do not consider the GHGs from the alternative fate of corn or of cornfields, implicitly assuming the corn wouldn't be grown if not for ethanol, and that idle land has a GWP of zero—both false. In fact, a substantial fraction of the corn used for ethanol would likely be grown in any case to meet the demand for feed, which is partially met by distillers grains coproduced with corn ethanol. A recent analysis concluded that 34% of the feed value of corn is available in distillers grains coproduced with ethanol (Jones and Thompson 2006).[15]

In contrast, waste management LCAs do account for the alternative fate of the waste when considering various management options (Finnveden, Johansson et al. 2000; Eriksson, Carlsson Reich et al. 2005; Lombardi, Carnevale et al. 2006). Typically, waste-to-energy alternatives receive a credit for methane emissions avoided by not landfilling. The equivalent for energy crops would be to credit bioenergy crop production for avoiding the emissions that would have occurred in the baseline case—which probably still involves crop production. However, the effects of a shift from feed to ethanol end uses for corn cascade through domestic and international markets, causing GHG emissions changes that can only be determined through equilibrium analysis.

Note that the comparative approach used in waste-to-energy analysis is consistent with the GHG accounting required under the Clean Development Mechanism (CDM) of the Kyoto Protocol. CDM project proposals must define a baseline for emissions under the business-as-usual scenario and demonstrate how the emissions reductions claimed by the project are additional to those that would have occurred anyway (CDM Executive Board 2006). In contrast, LCAs of biofuels from energy crops don't consider that the business-as-usual scenario for most land growing corn today for ethanol would be to grow corn for some other end use, or perhaps to grow some other crop, in either case with non-zero GHG emissions.

4.4. Marginal versus Non-marginal Analysis

Life-cycle analyses of crop-based ethanol aim to determine the impact of producing a marginal unit of ethanol, which, by definition, doesn't affect the market[16]. However, such a result is also, by definition, not policy-relevant. Public policy concerns non-marginal changes that necessarily involve one or more markets. The most pertinent climate policy question is: *What is the potential climate benefit of the large-scale ramp-up of ethanol production, and how does the particular ramp[s] chosen matter?* This question cannot be answered by performing a marginal analysis of a narrowly-defined engineering process and then extrapolating the result to the macro level without consideration of market impacts, but rather requires a more complex market equilibrium analysis (Delucchi 2004). Linear extrapolation is incorrect, in part, due to discontinuities (step functions) in both the marginal cost and CO_2 emissions from the different energy technologies that may be offset by biofuel product and coproduct production. The actual GHG offsets, therefore, depend on changes in *total* supply. Market dynamics include other non-linear behaviors such as feedbacks and thresholds. An example of a feedback is the "rebound effect"—if the increased supply of ethanol reduces fuel prices, the cost of driving would decrease and the number of miles driven would increase. An example of a threshold is the capacity of the market to absorb E85, which is determined by the number of flex-fuel vehicles on the road (and the

[15] Graboski (2002) computed a value of 72%, but at that time the ethanol industry comprised 54% wet-mills; the current fraction is 20%. Wet-mills generate coproducts with higher feed value than do dry-mills. Graboski also assumes the use of soy hulls (an otherwise unused residue of soybean production) to increase caloric content.

[16] Typical biofuel LCAs don't really model marginal production. Instead, they rely on various averages (e.g. wet and dry mills over decades of technological change and corn production across various states and years) while attempting to identify the marginal MJ of ethanol for this statistically-defined process. When using averages, it is more appropriate and meaningful to examine the impact of the total ethanol produced by the plants we've averaged—compared to having produced no ethanol at all.

willingness of motorists to use E85 in gasoline-only vehicles.) Beyond the fuel usable by these vehicles, the value of additional E85 plummets, at least in the short run.
A better approach to answering the stated question would be some form of integrated assessment model incorporating both GHG accounting and economic equilibrium modeling. This approach is explored in Section 6.

4.5. Coproduct Allocation

For production processes that result in multiple products, life-cycle analyses must decide how to allocate the inputs and outputs across the various coproducts. ISO 14040, the international standard for LCA, suggests avoiding allocation of inputs and effluents to coproducts by expanding the system boundaries to encompass the production of assumed substitutes for coproducts (ISO 2006). However, there are two flaws with this approach: (a) the assumed alternative may be only one of several viable substitutes, and (b) substitutability is generally not 100%. In fact, the actual result is determined by the market: the supply of coproduct *X* increases, and the market equilibrates supply and demand based on cross-price elasticities. In the extreme case of a market with perfectly elastic demand, all additional product would be absorbed, displacing nothing, and resulting in zero GHG emissions credit (Delucchi 2005). Although this extreme case may not exist in practice, it does illustrate that the GHG emission reductions are a function of price elasticity. The assumptions underlying system expansion break down further in the non-marginal case, where second-order market impacts can overwhelm primary impacts (Roland-Holst 2006).

Assumptions about coproduct credits are also dependent on macro-level market dynamics. In their study of bioenergy cropping systems, Kim and Dale (2005) assume that the unfermentable lignin fraction of cellulosic biomass is co-fired in existing coal-burning power plants. In this case, the biomass clearly displaces coal. However, this is likely a special case; cellulosic ethanol facilities are more likely to generate electricity by combusting or gasifying the lignin, exporting surplus electricity to the grid. What is displaced by this low marginal cost electricity depends on what type of power plant would otherwise be on the margin, and in most places, this is not likely a coal plant. If the marginal plant is fuelled by natural gas or biomass, the coproduced electricity would enjoy significantly lower GHG avoidance credit than is assumed in the Kim and Dale analysis, and is likely lower than would be computed using average grid emissions as is generally done in biofuel LCAs.

The power exported to the grid by any single cellulosic ethanol plant will displace energy from the marginal plant. In the aggregate, coproduced electricity from ethanol producers may cause long-run changes in the power sector. Thus, the coproduct credit for electricity production for the marginal unit of ethanol (or blended fuel) is a non-linear function of the total quantity produced, and dependent on whether one examines the short-run or long-run.

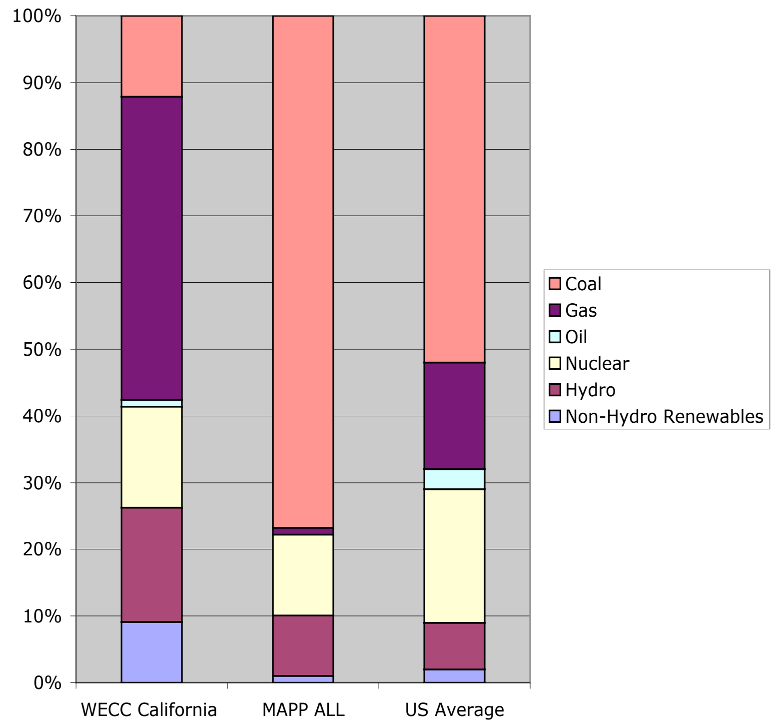
However, the non-marginal impacts the marginal analysis as well, since we need to know what is displaced by the electricity coproduced with ethanol in all the cellulosic pathways. In EBAMM, we assumed grid average electricity is displaced, but in reality, these low-to-zero marginal cost electricity plants will push out the supply curve and displace the marginal plant. As the type of plant at the margin varies with load, the correct average to use when computing coproduct credits is not that of the grid mix, but that of the marginal plants in the local region for each hour of the day over, say, a year. Again, the results computed from extrapolating from the marginal ethanol plant and from analyzing the whole market will differ given non-linearities in both the primary and coproduct markets.

It is also important to bear in mind the different results in a short-run and long-run analysis. In the short run, the increased low-marginal cost electricity production by biofuel plants will offset plants on the margin at all hours of the day, which will often be natural gas peakers during peak demand and more efficient natural gas or coal plants during off-peak hours. In the long-run, however, sufficient electricity coproduced with biofuels would displace marginal base-load plants, which in much of the US are likely to be coal-fired.

The net GHG benefit of using cellulosic EtOH is significantly influenced by the credit for coproduced of electricity. For example, in the *Cellulosic* (switchgrass) case modeled in EBAMM, the GHG credit for coproduced electricity (based on average US generation) is equivalent to 34% of the total GHG emissions from the agricultural and biorefinery phases. It remains to be seen how much of an error is introduced by using the emissions from average generation versus those of marginal generation. Figure 3 shows that the MAPP (Mid-continent Area Power Pool, serving several cornbelt states) has much more coal-fired power and little non-hydro renewable or natural gas-fired power compared to WECC California (Western Electricity Coordinating Council), thus the GHG emissions benefits by electricity coproduced with cellulosic ethanol in these two locations will differ significantly.

Figure 3. Fuel Mixes for Electricity Generated in the Midwest and in California

Low-cost, coproduced electricity from cellulosic ethanol facilities may displace natural gas or renewables in California and coal in the Midwest, resulting in very different greenhouse gas reduction benefits. (Source: US EPA Power Profiler, http://www.epa.gov/cleanenergy/powerprofiler.htm)



5. Regulating the Global Warming Impact of Biofuels

Many economists and policy analysts believe that the most economically efficient and least distorting approach to reducing the GHG impacts of energy use would be through including the cost of GHG emissions in the price of all energy products (Arrow, Jorgenson et al. 1997; Holdren and Leshner 2006; O'Hare 2006). This is usually envisioned as a carbon charge or tax, occasionally with a reduction in payroll taxes to offset the regressive nature of the carbon charge (Cramton and Kerr 1999; Metz and Intergovernmental Panel on Climate Change. Working Group III. 2001). However, this study examines the issues and policies relating to the life-cycle accounting of biofuel GHGs. Discussions of alternative approaches to reducing the GHG emissions from transportation, such as carbon charges, are beyond the scope of this study.

5.1. Review of Proposal for British Renewable Transport Fuels Obligation

Bauen et al. (2005) offer a detailed and well-reasoned proposal for the certification of GHG emissions from renewable transport fuels in the UK. The proposal includes several important insights, and grapples with many of the logistical challenges of tracking and certifying biofuels across the supply chain.

The report explores three main options:

1. No certification
2. Certification based on default values for feedstocks and processes (either with single default values per fuel, or differentiated by production pathway)
3. Certification based on verified process data, with a fallback to default values.

The authors conclude that option 1 offers no guarantees of GHG reductions; option 2 is somewhat better, but offers little incentive for producers to reduce GWI; and option 3 is not only the most beneficial approach in providing incentives to reduce GHG emissions, but it is also the most likely to survive challenges in the World Trade Organization (Bauen, Howes et al. 2005).

They propose a 3-tier approach to data collection that uses the best available data, while allowing for differences in willingness or ability to provide detailed data (Bauen, Howes et al. 2005). Tier A evidence is based on actual process data, used whenever available. Tier B evidence uses verifiable information about the types of farming systems and processes employed. Tier C relies on default factors based on the scientific literature, and is designed to be conservative so as to provide incentives for producers to provide Tier A or B evidence to earn additional credit.

The report also considers the costs of verification and tracking through the supply chain, and considers the net impact on fuel prices to be minimal. They estimate annual costs in the UK of about £225 (US$425) for farms of 250 hectares or larger, £700 (US$1350) per logistic (transport) company, and £2000 (US$3,800) for fuel processing plants[17] (Bauen, Howes et al. 2005).

While the Bauen, et al. proposal provides an excellent framework for developing a green biofuels index, the proposal fails to address several of the vexing issues raised in the present paper. One of these gaps derives from their study's exclusive consideration of biofuel pathways based on energy crops: were the authors to broaden their analysis to include waste-to-biofuels pathways, they would encounter conflicts with their "Consistency of Assessment" principle, which requires consistent system boundaries and coproduct allocation methods across pathways (Bauen, Howes et al. 2005). In addition, the report does not consider the role of markets in determining life-cycle GHGs, although they do characterize several shortcomings of the usual array of coproduct allocation methods (Bauen, Howes et al. 2005).

5.2. Agricultural Phase GHG Emissions

Agricultural GHG emissions are highly site-specific, as they are dependent on agricultural practices, soil condition, and climatic conditions. Precise crediting of low-GWI feedstock production requires either measuring or modeling soil GHG fluxes, plus accounting for the upstream and use-phase emissions attributable to agricultural inputs and fuel.

The ramifications of tracking site-specific emissions are explored briefly, followed by a more practicable solution.

[17] Converted 2005 values using http://www.xe.com/ucc on 4 Aug 2006, at which time £1 = $1.91.

Measuring Agricultural Phase GHG Emissions

One approach to assigning a GWI factor to agricultural feedstocks would be to measure or model each individual site. In theory, this would provide the most accurate accounting and therefore incentives based on biofuel GWI would flow to farmers according to their actual crop performance.

However, while it is possible to measure actual gas fluxes over energy crop fields, the cost is prohibitive, at approximately $50,000 per station for an "eddy covariance" system of the type used in research fields at the University of Nebraska-Lincoln (Cassman 2006).

An alternative to gas flux measurement is the use of a proxy. The quantity of free nitrogen in the soil under corn production can be estimated from the N application rate and the N concentration in a corn stalk. The soil nitrogen value could be multiplied by a constant to estimate N_2O flux, which is the most significant factor in field emissions (Cassman 2006). However, this approach accounts only for N_2O, soil carbon fluxes would need to be accounted for separately.

Another alternative is to model net emissions using agroecosystems modeling software such as DAYCENT. The US EPA uses DAYCENT for portions of the US Greenhouse Gas Inventory, and the model has been used to the study of GHG emissions from biofuel feedstock production (Kim and Dale 2005; US-EPA 2005). The DAYCENT model also underlies the COMET-VR voluntary reporting system that helps farmers manage soil C sequestration (USDA 2006).

As shown in the Kim and Dale (2005) study, DAYCENT reports soil carbon loss under conventional tillage and carbon sequestration under reduced tillage. However, recent research indicates that the data supporting these results is likely biased due to an inadequate depth of soil sampling (Baker, Ochsner et al. 2006). Baker et al. write:

> While conservation tillage practices may ultimately be found to favor soil carbon gain, the data reported to this point are not compelling. … This discussion should not be construed as a defense of the plow. There are many good reasons to reduce tillage: no-till and other conservation tillage systems can protect soils against erosion (Gebhardt et al., 1985), reduce production costs (Al-Kaisi and Yin, 2004), and decrease the consumption of fossil fuels (Phillips et al., 1980). These benefits have been well documented, and are in themselves sufficient to justify the promotion of conservation tillage strategies. However, the widespread belief that conservation tillage also favors carbon sequestration may simply be an artifact of sampling methodology. There is reason to believe that the shallow sampling employed in most studies introduces a bias. Studies that have involved deeper sampling generally show no C sequestration advantage for conservation tillage, and in fact often show more C in conventionally tilled systems. Gas exchange measurements also offer little support to the notion of a consistent soil C benefit from reduced tillage.

In summary, field-level monitoring is cost-prohibitive; modeling is possible, but requires observation of many field-level parameters, and the validity of present models with respect to a key element of GWI is in question; and proxies offer a means of estimating some, but not all, greenhouse gas fluxes.

The Bauer, et al. proposal suggests omitting soil emissions, at least initially (Bauen, Howes et al. 2005). However, this omission introduces a bias in favor of corn ethanol relative to cellulosic feedstocks and sugarcane, as N_2O emissions are greater per unit ethanol produced from corn than from these other feedstocks.[18]

Using Feedstock Averages

The purpose of including site-specific measurements in the GWI of biofuels would be to encourage producers to use lower-GWI practices. However, the challenges of measuring or modeling, and monitoring each site are significant. There are several reasons why an incentive based on the GWI of biofuels is not the ideal way to influence the practices of energy crop producers:

1. Reductions in GHG emissions resulting from changing agricultural practices can have significant non-climate benefits, e.g. reducing soil erosion and eutrophication. Any incentive payment via biofuel GWI ratings would either fail to capture these additional external benefits, or if it did, the payment would be excessive relative to that received by less-polluting biofuel pathways.

   For example, a pilot program by the Institute for Agriculture and Trade Policy in Minneapolis that paid farmers to convert to more sustainable practices (such as reduced tillage, rotations, and cover crops) concluded that the required payment was approximately \$50/acre (IATP 2005; Kleinschmit 2006). Assuming yields of approximately 370 gallons ethanol per acre of corn, this payment would add \$0.135 to the cost of each gallon of ethanol, roughly equivalent to \$400 per ton carbon avoided, nearly twenty times the current price on the European carbon market.[19]

2. Soil C sequestration is reversible, whereas reducing emissions is not. Treating reversible sequestration as equivalent in GHG accounting fails to account for the risk of re-emission. As noted above, the relationship between tillage and soil C sequestration is not settled, so while we do want to promote soil C sequestration, we would want to treat it distinctly from avoided emissions.

3. Monitoring practices is far simpler than measuring or process-level modeling GHG fluxes. Modeling would require monitoring agricultural practices (as model inputs) as well as soil condition, temperature, and precipitation.

4. Only 18% of the corn crop is currently consumed for ethanol production. It is unclear whether a low-GWI benefit would affect production practices, or simply cherry-pick the lowest-GWI corn available for ethanol production. However, to the extent that payments

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[18] Modeling in EBAMM indicates that the field emissions of N_2O from corn (*Ethanol Today* case*)* are 301 g CO2e per liter whereas the field N_2O emissions for switchgrass (*Cellulosic* case) and Sugarcane are both approximately 70 g CO2e per liter. These are point estimates using the IPCC direct emissions factor. The uncertainty range for corn is of correspondingly greater magnitude.

[19] Assuming that each gallon of ethanol substitutes directly for 0.67 gallons of gasoline and that each unit of ethanol results in an 18% GHG reduction (as per EBAMM), each gallon of ethanol would avoid 0.67 * 0.18 * 20 lbs CO2e per gallon gasoline * 12/44 = 0.66 lbs C per 13 ½ cents, or \$409 per ton carbon. The PointCarbon.com website shows a closing price of €17 on Aug 22, 2006, or about US\$22. This simple analysis assigns *all* carbon savings to the agricultural phase; sharing these reductions with the biorefinery increases the cost per ton of carbon avoided.

raised the price of low-GWI corn, they would induce some growers to use lower-GWI practices.

5. As illustrated in Figures 4 and 5 below, the difference in GHG emissions from the agricultural phase for any single energy crop is smaller (about 400 g/MJ for corn) than the range of emissions across biorefineries (about 800 g/MJ for corn), and the prior is largely due to predictable differences such as irrigated versus rain-fed production. The effort required for site-specific accounting therefore may not offer commensurate benefits compared to relative ease and importance of accounting for biorefinery emissions.

6. There are significant uncertainties surrounding the N_2O emissions from agriculture, including both direct emissions from the field and indirect emissions from nutrient runoff. An accounting system would need to select a value from this wide uncertainty range as representative. For example, the guidelines issued by the Intergovernmental Panel on Climate Change (IPCC) suggest that 1.25% of the synthetic nitrogen applied to agricultural soils will be emitted as N_2O, although this is considered a default value, with a range 0.25% to 2.25%, and it accounts only for direct field emissions. A sensitivity analysis in EBAMM of the range of GHG emissions from nitrogen fertilizer and lime application for corn ethanol indicates that the choice of N_2O emissions factor alone controls the magnitude of GHG emissions and whether these are greater than or less than those from gasoline. The best estimate for the GHG emissions in the *Ethanol Today* case shows an 18% reduction versus gasoline, yet when including uncertain emissions from lime and N fertilizer emissions, the range is a 29% reduction to a 36% increase in GHG emissions versus gasoline.

Figure 4. Agricultural Phase GHG Emissions for Various Ethanol Feedstock Pathways

Figure 4 illustrates the range of GHG emissions from a variety of ethanol feedstock production pathways. A liter of ethanol produced from energy-efficient corn grown in rain-fed conditions (e.g. Minnesota) releases 478 g CO_2 equivalent emissions in the agricultural phase, whereas ethanol from most energy intensive corn (Nebraska) releases 931 g/L. Switchgrass is uniformly better than corn, though agricultural phase GHGs for heavily-fertilized switchgrass approach those of efficiently-grown corn. The principle difference between the switchgrass cases in GREET (415 g/L) and EBAMM (189 g/L) is the assumed N fertilizer application rate (50 kg/ha in EBAMM, 157 kg/ha in GREET). The Minnesota and Nebraska feedstocks were modeled in EBAMM using data from Shapouri, et al. (2004).

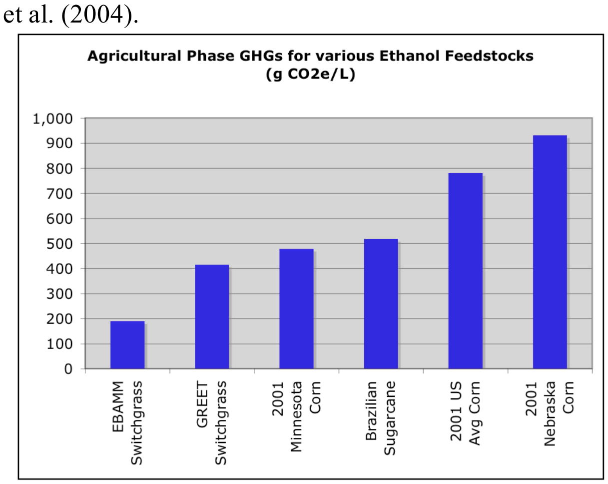
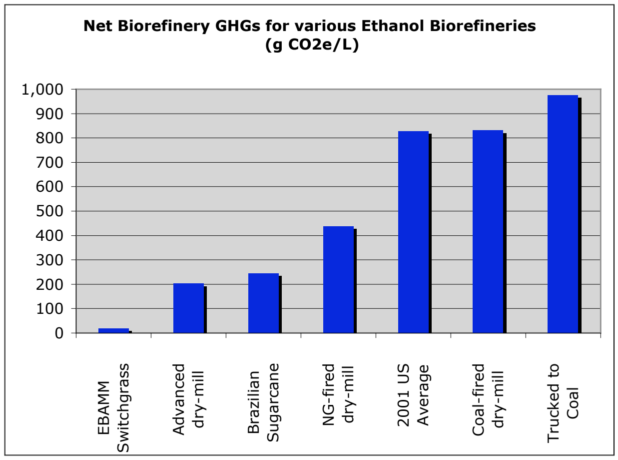


Figure 5. Net Biorefinery GHG Emissions for various Ethanol Biorefineries.

Figure 5 shows the range of GHG emissions for the biorefinery phase of various production pathways, net of coproduct credits. The worst corn case (based on the EBAMM CO_2 Intensive case, emits nearly five times the GHGs of the advanced dry-mill by trucking corn from Nebraska to South Dakota to a coal-fired dry-mill. (GREET Switchgrass is not depicted because the EBAMM Switchgrass simply adjusts the GREET system boundaries for commensurability with the other EBAMM cases.)



It would be simpler, and arguably, better, to use average agricultural-phase emissions when computing the GWI of energy-crop based biofuels. Rather than monitoring individual sites, we would compute an average GWI value for each feedstock, further differentiated by regionally distinct practices such as irrigation and liming. Indeed, a default value computed this way would be required in any case for feedstocks grown under unmonitored conditions, e.g. imports, and for non-energy crop feedstocks such as forestry thinnings, agricultural residues, and municipal solid waste.

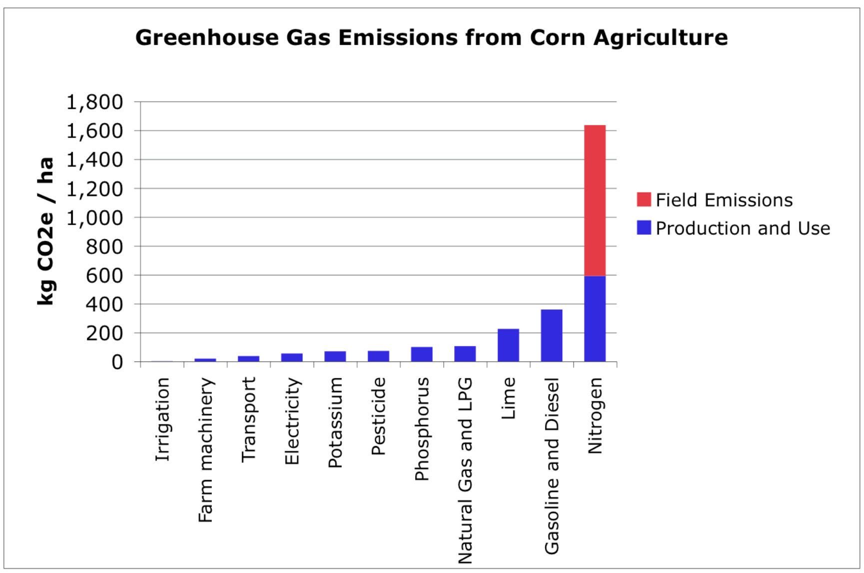
Determining Average Agricultural Phase GHG Emissions

Use of average emissions values will still require measurement or monitoring of emissions, but at a greatly reduced number of sites. The number of sites to measure would be a function of the number of distinct production regimes that were readily identifiable, probably using large regional (multi-state) boundaries. While it is beyond the scope of this paper to determine these boundaries, the principle would be to examine yield and input data to identify regional breaks in say, irrigation versus rain-fed production. Factors that are a function of farmer choice, such as tillage and nitrogen application rate, would be averaged across the region. These measurements might occur annually or every few years to capture systemic changes in practices that impact GWI, such as reduced tillage or increased use of biodiesel on the farm.

Figure 6 illustrates the influence of various agricultural inputs on the GHG emissions from corn production. These are clearly dominated by nitrogen fertilizer use. Crop yield (not graphed) is also a significant determinant of emissions since it operates as a divisor when computing emissions per unit of biofuel produced.

To compute the GHG emissions from this phase, the mass of each input is multiplied by the embodied energy per unit mass, resulting in the life-cycle energy use per input. Energy values are then combined with assumptions about the GHG emissions per unit energy to yield per-input GHG emissions. These values are then summed to compute total emissions per hectare or per kg of feedstock. These parameters can be divided into two sets: variables and constants. The variables need to be measured and averaged for each feedstock and region. The constants, e.g. the embodied energy in a gallon of gasoline or diesel, should be held constant across all regions to ensure commensurability. The embodied energy in nitrogen fertilizer is a special case in that it depends on the specific type of fertilizer applied. Treating this as a variable and accounting for it on a regional level could help influence farmers to choose less GHG-intensive variants of N fertilizer, although if this choice involves any yield reduction, free-riding would likely limit the GHG reductions.

Figure 6. Greenhouse Gas Emissions from Corn Agriculture.
Agricultural phase greenhouse gas emissions for the *Ethanol Today* case in EBAMM are completely dominated by the contribution from nitrogen fertilizer. The value shown for nitrogen includes both upstream (fertilizer production) and field emissions. Field emissions shown are calculated using the default IPCC emissions factor.



Input application rates will differ from field to field and region to region, and must therefore be averaged within regional cropping systems. The per-unit-mass energy and emissions factors, however, should be average national values that are applied to all regions, recognizing that these factors are generally untraced commodities. Tracking actual inputs back to their production facilities would therefore be impractical.

Alternative Strategy: Monitor Practices rather than Emissions

Besides significant measurement, monitoring, and tracking challenges, biofuels are an inappropriate lever with which to try to reduce agricultural GHG emissions. Currently, only 18% of the nation's corn provides 95% of the ethanol supply. If regulated for biofuels only, the low-

GWI corn might simply be cherry-picked for ethanol with the high-GWI corn going to the much larger—and unmonitored—feed market.[20]

A better approach would be to encourage all farmers to manage nitrogen and reduce tillage. Besides offering GHG reduction benefits, these practices also reduce soil erosion and nutrient runoff. Improved input management and reduced tillage have clear qualitative benefits in reducing GHG emissions as well as soil erosion and nutrient runoff. Promoting these practices will provide benefits even if the GHG reductions are not measured or estimated at every site, and practices are more easily audited than are specific changes in soil composition and gas fluxes (Tilman, Cassman et al. 2002).

Table 5. Parameters that Vary with Feedstock and Region

Agricultural Phase Variables (kg/ha)
N Application rate
P2O5 application rate
K2O application rate
Lime application rate
Herbicide application rate
Insecticide application rate
Seed rate
Transport energy
Gasoline
Diesel
Natural gas
LPG
Electricity
Energy used in irrigation
Farm labor
Farm machinery
Crop yield

Table 6. Parameters that are Constant across Feedstocks and Region

Agricultural Phase Constants (MJ/kg except where noted)
Nitrogen embodied energy
Phosphorus
Potassium
Lime
Herbicide
Insecticide
Seed
Transportation of inputs to farm (MJ/ha)
Farm machinery
Inputs packaging

The Conservation Security Program enacted in the 2002 Farm Bill does exactly this. Under this voluntary program, farmers devise resource-management plans specific to their farmland in return for 5 to 10 years of annual payments (McKnight Foundation 2005). Payments such as

[20] This is related to, but distinct from "leakage" which is generally defined as the increase in emissions from an unregulated area to compensate for the reductions in a regulated area. It's not clear that regulating the GWI of biofuels would induce increases elsewhere.

these for environmental services are acceptable under WTO rules, unlike the present per-unit subsidies, which are a source of contention in international trade negotiations.

However, funding for the CSP has been inadequate. Due to administrative and funding limitations, only one watershed is targeted each year, and farmers do not know when their watershed will be selected. Given that they must already be implementing conservation practices to receive payments, farmers would have to commit to conservation without knowledge of when and if they will begin receiving CSP payments. If the program were available to all farmers, CA could require that all corn ethanol imported into or produced in the state be derived from corn grown under an approved Tier III CSP program, which requires farmers to address all major environmental concerns. The average GHG balance of corn could then be that of all corn acres enrolled in the CSP.

5.3. Feedstock Conversion GHG Emissions

Regulating GHG impacts at the biorefinery is relatively straightforward, as it involves monitoring on the order of 150 US facilities, plus imports. As a sequential industrial process, ethanol production is far less complex and uncertain than agricultural feedstock production.

The following data is required per facility to determine the biorefinery-phase contribution to fuel GHG emissions:

- Feedstock GWI, per unit mass. This can be averaged across feedstock purchases.
- Process fuels
    - Primary energy source(s) and quantity used per liter of biofuel production
    - Primary energy source(s) and quantity used for drying (if delivering DDGS)
    - Energy use associated with collecting and compressing CO_2 (if captured and sold)
- Coproducts
    - Quantity of electricity produced
    - Primary energy source for electricity production and the quantity of heat versus electricity produced per unit of primary energy
    - CO_2 emissions from fermentation: vented, or collected and sold?[21]
- Electricity imported
- Grid region (to determine CO_2 emissions per kWh generated or avoided)
- Feedstock transport mode and average distance to plant
- Other energy uses in the biorefinery not considered above

An accounting model would use standard factors for emissions from electricity generation (based on generation profiles for each region) and from fermentation.

Each biorefinery would need to track the GWI in g CO_2e/kg of feedstock used, averaging these GWI values on a mass-weighted basis over designated time periods, e.g. per year. If a biorefinery purchases its corn from the local region, the use of averages greatly simplifies this process, as all feedstock will have the same GWI rating. Producers such as Pacific Ethanol,

[21] It's doubtful that any GHG benefit accrues with the sale of CO_2 from biorefineries at this time, given that the CO_2 market is flooded. If a biorefinery can sell CO_2 at low cost, some other CO_2 is likely no longer sold and is vented elsewhere. The result is no net GHG reduction, just an additional energy cost for compression, and additional income. This analysis would obviously change if the CO_2 were sequestered.)

which import corn into California, will have the option to purchase low-GWI corn if market conditions warrant the additional cost.

The accounting system would need to define standard coproduct credit values for all coproducts such as electricity (by region) and DDGS, taking into account current market conditions. Coproduct credits could be updated annually, or perhaps more frequently, as necessary to account for changing market conditions, e.g. saturation of the DDGS feed market or changes in the carbon intensity of the marginal electricity generator.

5.4. Cap and Trade for GWI-Certified Biofuels

With a measurement and tracking system in place for the GWI of biofuels, it becomes feasible to set regulatory limits for GWI, ensuring that climate benefits result. For example, California could implement a "cap and trade" system to limit the GWI biofuels, allowing low-GWI producers to sell credits to higher-GWI producers. Biorefineries would have several ways to meet the cap, including: (a) choosing an inherently low-GWI feedstock such as sugarcane or switchgrass, (b) choosing a relatively low-GWI producer for a "standard" feedstock such as corn, (c) improving the GWI of their plant through the use of bioenergy or other energy and carbon efficiency improvements, or (d) purchasing credits from refineries that were able to producer biofuels with GWI below the regulated limit.

As noted earlier, with a cap in place, it is safe to assume that the average GWI of biofuels in the state would just meet the regulatory limit, assuming a binding cap. This in turn allows a single per-fuel Fuel Adjustment Factor as conceived under AB 1493 to be meaningful. Knowing the average GWI of biofuels used in the state also facilitates monitoring of progress toward the state's climate policy goals.

Default Grading and Optional Certification

The default GWI for untracked biofuels should be based on an estimate of the average industry emissions, using worst-case assumptions about feedstocks. This provides a floor for benefits without requiring certification. However, both domestic producers and imports (and international producers) can opt into the low-GWI biofuel certification system to receive higher credits. Emissions from shipping (domestically and internationally) must be included. The GWI cap would be set below this value to encourage low-GWI producers to opt-in to the certification system. As firms opt in, the default average value would be re-computed, excluding the certified low-GWI firms, thereby avoiding double counting. This will result in the default value increasing, providing additional incentives for lower-than-average GWI firms to opt-in.

Imports and Leakage

Leakage occurs when emissions increase in unregulated areas that counteract reductions in a regulated area. For example, under a regime that prohibited biofuels produced on deforested land, producers could convert cropland to palm plantations, while clearing rainforest to provide more cropland. Bauen, Howes, et al. (2005) recommend disallowing biofuels produced on recently cleared land from a regulated trading regime. However, this is not guaranteed to prevent leakage, as land is fairly fungible: lands cleared less than, say, 10 years ago might be used for export markets where no restrictions apply, while land cleared more than 10 years ago would be used for regulated markets. Note that this can be a problem for domestically produced as well as imported biofuels, most notably if Conservation Reserve Program (CRP) or other grasslands are converted to row crops such as corn and soybeans.[22]

6. Toward a Second-Generation Life-cycle Accounting Model

The methodological issues discussed in Section 4 result from the narrow engineering perspective usually applied to life-cycle analysis. This perspective is useful in that it allows industry to understand and improve the environmental performance of production processes. However, analyzing the greenhouse gas benefits of the large-scale use of biofuels is a far more complex undertaking due to interconnections amongst the markets for biofuels, food, feed, land, electricity, petroleum, and automobiles.

History may identify 2006 as the year biofuels reached critical mass in the public, political, and financial spheres, due to a confluence of concerns about climate change, oil depletion, and energy security. With this transition toward greater rhetorical and industrial prominence comes a responsibility to deepen our approach to analyzing the implications of this global trend. Perhaps the most important analytical advance would be to integrate market dynamics and life-cycle analysis.

6.1. Integrating Markets Dynamics and LCA

It is theoretically possible to build a highly resolved integrated model incorporating the level of technological and economic detail required to analyze the climate benefits of biofuel production. However, such an undertaking would need to be global in scope (e.g. reduction of corn exports from the US affects food production in importing countries such as Mexico and China, with unknown net GHG emissions outcomes) and technologically richer yet than models such as GREET or Mark Delucchi's LEM to account for the wide variety of feedstocks, regional agricultural practices, and biorefinery configurations described earlier.

Adding Markets to LCA

One approach to this integration would be to start with an existing LCA or economic model and add the complementary component. This could be approached from either direction, i.e. by integrating market behavior into a classical life-cycle emissions analysis model, or by adding the necessary level of technological detail to an integrated assessment model that already consider markets and greenhouse gases. Delucchi (2005) concludes that the prior approach is preferable, due to the required technological richness. However, moving from marginal to non-marginal analysis highlights several limitations of this approach. First, the non-marginal analysis is strongly influenced by the policy environment, so the constraints or incentives provided by these policies need to be represented in the model. Moreover, as a fundamental purpose of climate policy is to influence technological choice, a useful model would endogenize this choice. In contrast, existing LCA models examine individual pathways in isolation based on user-defined technological assumptions, without consideration of macro-scale effects or policy constraints.

Adding Technological Detail to an Integrated Assessment Model

Another approach would add to an existing Integrated Assessment Model (IAM) the technological detail required to model the full range of biofuel pathways. The advantages of this approach are (a) IAMs are inherently interdisciplinary, typically spanning economics and GHG

[22] See Bauen, et al. (2005) for discussion of how biofuel certification relates to international trade rules.

accounting, and (b) they are designed to evaluate non-marginal change, and (c) are often designed to evaluate the effect of policy on markets and GHG emissions (Center for International Earth Science Information Network (CIESIN) 1995; Kelly and Kolstad 1999).

For the purposes of regulating biofuels GWI, however, the net changes in GHG emissions must be attributable to individual pathways. Integrated assessment models are not designed for this purpose.

6.2. Attributing Non-marginal Changes in Emissions to Fuel Pathways

Considering non-marginal production levels requires us to an attribute appropriate fraction of the macro-level effects back to each individual fuel pathway. This problem arises because although biofuel production involves numerous pathways with distinct GHG profiles, each final fuel (e.g. ethanol, methanol, hydrogen) is an essentially uniform commodity. The total change in GHG emissions due to the production and use of each biofuel is thus the sum of three components:

a) Production-phase emissions
b) Coproduct credits for avoiding some baseline emissions
c) Avoided emissions due to substitution for petroleum or other fossil liquid fuels

The first two parts are pathway dependent, whereas the third part is pathway independent, but is a function of the total quantity of each fuel and of market and policy interactions. Life-cycle analyses to date have focused on *a*, used various rough approximations for *b*, and treated *c* as if 100% substitution were assured.[23] Ideally, *c* could be examined in a CGE model, although this model would be sensitive to assumptions about the supply and GHG profiles of petroleum and its synthetic alternatives. It's unlikely that existing CGE models represent fuel markets at this level of technical detail.

The interactions between the feed, food, fuel, electricity, and land markets are complex, involving feedbacks, thresholds, and properties that emerge only at the non-marginal scale. For example, if DDGS production saturates the animal feed market, some producers may resort to burning distillers grains, creating a new pathway with a distinct emissions profile. As with all complex systems, it is impossible to tease out the specific contribution of any single element in isolation from the system in which it is embedded. While it is feasible to consider individual fuel pathways under *ceteris paribus* conditions, this will result in an analysis in which the whole (i.e. the economy-wide GHG emissions from a mix of pathways) may not be simply the sum of the parts.

We can, however, approximate the relative contributions from distinct fuel production pathways for the purposes of regulation, incorporating the effects of non-marginal (i.e. real world) production levels, with feed and fuel substitution based on estimates of cross-price elasticities. A per-mile GHG rating could be derived from this analysis, but it would involve selecting a non-marginal production quantity, say 100 million gallons, and then determining the total change in GHG emissions based on that level of production under each pathway, considering corresponding non-marginal changes in coproduct markets. The per-mile GHG estimate would

[23] Delucchi (2005) uses "Net Displacement Factors" as an estimate of the degree of coproduct and fuel substitution. NDFs are estimated at 0.75 without rigorous theoretical backing, and serve mostly as placeholders in the LEM.

then scaled down from this non-marginal quantity rather than using a bottom-up engineering LCA approach that ignores economics.

The recommended approach is therefore to use process LCA to account for primary environmental impacts, in conjunction with equilibrium analysis to account for coproduct credits and to compare the world that includes a non-marginal quantity of biofuel production against a world without the biofuel. In other words, use standard LCA for primary impacts, and general equilibrium analysis to determine secondary effects. It is important to note, however, that the results for each fuel pathway would be useful only in a relative comparison scheme such as a biofuel rating. To determine the overall GHG benefits from the fuels would require a separate analysis that considered the sum of the emissions from each pathway minus the credit for displacements in the petroleum fuel market.

7. Conclusion

Biofuels offer significant GHG reduction potential. The actual benefits, however, are highly variable and dependent on choices of feedstock, agronomic practices, and biorefining processes. Without a carbon charge or other means of internalizing environmental costs into agricultural and biofuels markets, economic forces will result in suboptimal GHG benefits from using biofuels. Maximizing these benefits is therefore likely to require regulation.[24] Regulation, in turn, requires measurement of net GHG emissions, which is non-trivial, but feasible. The same measurement would be required whether regulating only biofuels or instituting a CO_2 cap that included the energy and agricultural sectors.

While a carbon charge or an economy-wide CO_2 cap would be preferred solutions, it may be less difficult politically to establish target GHG levels for ethanol blends used in California. Regulating biofuels would ensure that their use results in strong GHG reductions, and would establish a market for low-GWI biofuels in California and perhaps in the ten other states planning to implement automotive CO_2 regulations. Measuring (or estimating) and monitoring emissions would also be required in the implementation of a carbon charge, so these policies are not in conflict, although biofuels regulation could conceivably dilute pressure for more effective policy.

It may not be feasible to perform field-level accounting of agricultural phase GHG emissions, due to significant measurement, monitoring, and tracking challenges. It would be preferable to use non-biofuel incentives such an expanded Conservation Security Program to broadly promote environmentally preferable agricultural practices such as nitrogen management and reduced tillage, thereby affecting the entire agricultural sector, not just the small fraction producing biofuel feedstocks. For the purposes of GHG regulations of ethanol, it would be better to use regional per-crop averages for emissions. Under such a system, cellulosic crops would rate better than corn, and rain-fed corn would rate better than irrigated, but we wouldn't distinguish between crops of the same category at the field or farm level. This approach captures the most significant agricultural feedstock and regional differences while avoiding significant headaches. Measuring emissions from feedstock conversion is comparatively easy, and perhaps more likely to affect

[24] In theory, an inform/implore strategy could also be effective. (In theory, theory and practice are the same, but in practice this is not so.)

outcomes given the much broader range of conversion technologies and options for process heat and power.

In summary:

1. The GWI range for biofuels is extremely wide, from worse than gasoline to nearly 100% reduction for some pathways. Greenhouse gas reductions are neither guaranteed, nor will they be maximized, if left to the present market.
2. Regulating carbon in general, or biofuels in particular, would provide incentives to reduce the GWI of biofuels and promote more beneficial climate outcomes.
3. First-generation engineering life-cycle models of biofuel production fail to account for important market interactions. A new generation of models will be required to more accurately account for changes in GHG emissions due to the large-scale use of biofuels.
4. California should take several steps to promote low-GWI biofuels, including regulating the GWI of biofuels and developing second-generation "market-based" life-cycle tools to standardize the GHG accounting.

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