Addressing Biofuel GHG Emissions in the Context of a Fossil-Based Carbon Cap

DISCUSSION PAPER

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ABSTRACT

Renewable fuels have been promoted as a climate solution as well as for their energy security and domestic economic benefits. Analysts often assume that, other than process emissions, biofuels emit no net CO_2 because their biogenic carbon was recently absorbed from the atmosphere. This "renewability shortcut" has shaped both public perception and public policy to date. Cap-and-trade policies follow GHG inventory conventions that use the shortcut and so fail to properly account for biofuel emissions. They also miss portions of the upstream GHG emissions from fossil-based transportation fuels, although most such emissions are trade related. Lifecycle analysis (LCA), which attempts to account for all of the GHG impacts associated with fuel production, has been proposed as a means of regulating fuels for climate policy. LCA is used to qualify certain fuels for the U.S. federal renewable fuel standard (RFS) and also forms the basis of a low-carbon fuel standard (LCFS). However, as LCA system boundaries have expanded to address market effects such as induced land-use change, its application in policy has become controversial.

This paper examines these issues, quantifies GHG emissions missed by cap-and-trade policies as commonly proposed, and identifies ways to address biofuel emissions in the context of a carbon cap that covers major emitting sectors. Resource economics suggests that policy should be defined by annual basis accounting of carbon stocks and flows and other GHG fluxes rather than by LCA. This perspective suggests the use of a three-part approach: (1) correct specification of the transportation sector point of regulation with careful carbon accounting at the point of finished fuel distribution; (2) voluntary fuel and feedstock GHG accounting standards to track CO_2 uptake and uncapped GHG emissions throughout the fuel supply chain; and (3) a land protection fund for purchasing international forest carbon offsets to mitigate leakage. While an RFS can remain in place to drive volumes of specified fuels into the market, this approach avoids the need for either LCA requirements in the RFS or the added regulatory layer of an LCFS. Integrated into a cap-and-trade framework, this market-based approach would provide biofuel and feedstock production with a carbon price incentive tied to the cap, creating a more complete carbon management framework for the transportation fuels sector.

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EXECUTIVE SUMMARY

Most national climate legislation includes transportation fuels under a GHG emissions cap by requiring refiners to submit allowances to cover the fossil carbon content of their products. By so serving as a point of regulation, refiners perform an accounting function on behalf of all actors (consumers, automakers, system planners and fuel suppliers) whose decisions collectively determine GHG emissions from the transportation sector.

While having fuels in the cap is necessary for an effective climate policy, it is not sufficient for addressing all fuels-related emissions. In particular, it fails to cover many GHG emissions during the production of biofuels and their feedstocks. It also risks emissions leakages through the interlinked fuels and agricultural commodity markets that cross the boundaries of capped and uncapped sectors both domestically and internationally. Thus, the carbon accounting system under a fossil-based cap alone is incomplete when it comes to biofuels.

This paper explores ways to close the gaps in cap-based emissions accounting for biofuels while mitigating the associated leakages. To remedy the situation without an additional layer of regulation, a cap-and-trade system can be refined through the following three-part approach:

(1) Require refiners to submit allowances sufficient to cover the *conventional fuel equivalent* carbon content for the energy value of all transportation fuel distributed, regardless of fuel type, except to the extent it is rated as demonstrating lower net *uncapped* direct GHG emissions.

(2) Establish Fuel and Feedstock Accounting Standards (FFAS) for rating fuels and feedstocks based on *uncapped* GHG emissions throughout their supply chains; while voluntary, FFAS ratings would provide a way to reduce refiners' allowance requirements as defined by Part (1).

(3) Address market-mediated impacts (indirect GHG emissions versus those in the direct supply chain) through a Land Protection Fund (LPF) for purchasing international forest carbon offsets commensurate with induced fuels-related GHG emissions not otherwise accounted for.

This approach would strengthen the robustness of a fossil-based carbon cap covering transportation fuels. Incentives for leakage are minimized by using a rigorous specification (Part 1) for allowance submission at the point of regulation, while the FFAS (Part 2) and LPF (Part 3) represent non-regulatory complementary measures that fill gaps in fuel GHG accounting by tracking uncapped emissions and mitigating leakage. Coupling allowance submission requirements to the biofuel supply chain enables the cap to drive innovation, providing a cost-effective, technology-forcing policy for fuels. The effectiveness of this approach hinges on establishment of a GHG cap-and-trade system, into which the FFAS and LPF must be integrated to ensure environmental integrity.

The renewability shortcut

As commonly proposed, a fossil-based carbon cap excludes biogenic CO_2 emissions, treating the CO_2 reduction implied when substituting bio-based carbon for fossil carbon in fuels as fully additional. Aside from process emissions, the fact that the CO_2 was recently recycled from the air through plant growth is assumed to mean that biofuel use emits no net CO_2 over what would have been emitted if biofuel were not used. This "renewability shortcut" is, however, questionable. One

issue is that of the additionality: whether growing biofuel feedstocks absorbs more CO_2 than would have otherwise occurred when cultivating plants for other purposes or leaving land to unmanaged ("natural") plant growth. A related issue is emissions leakage: an effect tied to the economic coupling of biofuels from an uncapped sector substituting for fossil fuels in a capped sector. Questions include the extent of land displacement due to market linkages, including indirect land-use change that aggravates tropical deforestation and leads to a large release of stored carbon.

These concerns have not been considered in either cap-and-trade proposals to date or in policies to promote biofuels through mandates and subsidies. Until recently, neither were they adequately considered in proposals to regulate fuels through lifecycle analysis. While comparing fuels according to "carbon footprint" has simplistic appeal, and such analysis can be expansive in scope (covering indirect land-use change and other secondary effects), it is unclear that lifecycle analysis provides an appropriate framework for regulation. Moreover, lifecycle accounting is not consistent with the fully additive annual basis carbon accounting needed to rigorously track GHG emissions under a cap, which is in turn necessary for the overall environmental integrity of any climate protection regime. This paper explores one approach for addressing biofuel-related emissions through mechanisms integrated into cap-and-trade policy rather than complementary policies that lack accounting consistency with the cap. An alternative approach (not explored here) might be to treat biofuels and other forms of bioenergy as offsets, that is, under rules governing how GHG reductions from uncapped sources are credited against capped sources.

Emissions missed by a fossil-based cap

To put the concerns about biofuel-related GHG emissions in context, the first section of this paper provides a background analysis that estimates ranges of emissions missed by a fossil-based carbon cap. Missed emissions include those that occur either domestically in uncapped sectors or overseas in countries that do not have carbon caps in place (i.e., most countries other than the European Union). The GHG emissions missed by a cap include not only those associated with biofuels, but also emissions associated with overseas production of petroleum fuels from both conventional and unconventional sources.

Estimates are developed using a sketch model of U.S. transportation sector GHG emissions derived from recent editions of the Department of Energy (DOE) *Annual Energy Outlook* (AEO). The AEO projections for bio-based fuels under the Renewable Fuel Standard (RFS) and for international sources of petroleum and petroleum products were compared to a modified reference projection that reflects vehicle efficiency improvements only, without the apparent reductions that DOE projects using the renewability shortcut (i.e., excluding the biogenic carbon in fuels).

Although uncertainties are large, estimates of biofuel emissions missed by a fossil-based cap range from 89–177 $TgCO_2e$[*] in 2020, or roughly 5%–9% of a baseline level of 1,985 $TgCO_2e$ for U.S. transportation sector direct CO_2 emissions in 2005. A greater quantity of missed emissions is tied to imported petroleum products, amounting to roughly 253 $TgCO_2e$ in 2020, including overseas emissions from both conventional refining and heavy crudes.

Counting both biofuels and petroleum products, total transportation-related emissions missed by the cap range roughly 342–430 $TgCO_2e$ in 2020, or 17%–22% of sector's 2005 direct emissions. In other words, missed emissions are comparable in magnitude to the level of GHG reductions under consideration for that time frame. Note that even in 2005, 183–208 $TgCO_2e$ would have been

[*]Teragrams (Tg) CO_2-equivalent, where 1 Tg (10^{12}g) = 1 million metric tons (MMT). Note that 1 $TgCO_2$ = 44/12 (3.667) TgC for comparison to values given on a carbon (rather than CO_2) mass basis.

missed under a cap set at the 2005 level. The majority of these baseline missed emissions are from overseas refining of conventional petroleum (i.e., the emissions embodied in imports of gasoline and other petroleum fuels), which are not part of the U.S. GHG inventory.

Toward carbon management for transportation fuels

Including transportation fuels under a fossil-based carbon cap would put most of the sector's GHG emissions into a carbon management framework. The vast majority of sector emissions is CO_2 from end-use fuel consumption. Measurement of these emissions is indirect, relying on tallies of fuel use (based on taxes and other commercial records), but accurate because fuel chemistry is well defined. Most GHG emissions at domestic refineries and other stationary sources associated with fuel supply, including emissions from fossil energy used for biofuel production, also fall under cap-based management. Although upstream emissions from imported fuels are missed by a U.S. domestic carbon cap, such emissions can be considered no different than those embodied in overseas production of other imports (such as steel, other metals and intermediates, durable goods, imported foods and fibers, and so on).

The missed emissions associated with biofuels, however, entail special concerns because of the renewability shortcut. This problem can be considered one of incomplete information: lack of facility-specific data on uncapped emissions from the feedstock and fuel supply chain prevents the carbon market from addressing significant portions of biofuel-related emissions. In general, an information gap exists for all biofuel-related emissions other than those from purchased fossil energy already under the cap. The approach outlined here can be seen as a way to address this information barrier by specifying mechanisms to track and mitigate uncapped emissions. It thereby exposes biofuel and feedstock production and its associated impacts to the carbon price signal from the cap, creating a more complete carbon management framework for the sector.

Because the set of concepts outlined here addresses only biofuel-related emissions, it potentially addresses 89–177 $TgCO_2e$ (26%–41%) of the total 342–430 $TgCO_2e$ of U.S. transportation fuels-related emissions that this analysis suggests would be missed by a fossil-based carbon cap in 2020. However, essentially all of the remaining emissions are trade-related, being embodied in imported conventional fuel products. Other mechanisms will be needed to address those and the similar emissions associated with imported non-fuel products regardless of the approach taken for biofuels.

Features of the approach outlined here

This three-part approach addresses biofuels in the context of a fossil-based carbon cap covering transportation as part of an economy-wide program. As noted, it does not address "high-carbon" petroleum fuels. Neither does it address electricity and hydrogen, which would be handled by a cap's coverage of stationary sources where they are produced. A broader question not analyzed here is whether any form of bioenergy (as might be used to produce electricity and hydrogen) is properly treated under cap-and-trade or renewable energy policies that use the renewability shortcut.

Regarding this paper's focus on biofuels, several features of the approach are worth highlighting:

- **Under this approach, the cap itself becomes the primary driver for GHG emissions reduction in the transportation fuel and feedstock supply chain.**

Rather than using a bottom-up, technology-based regulation such as a LCFS, innovations in fuel production would be driven in a top-down, market-based manner based on their value for avoiding allowance costs. Crucial for market integrity is the Part (1) stipulation that allowances be submitted to cover the direct (chemical) carbon content of all distributed fuel on a conventional fuel (gasoline or diesel) energy-equivalent basis unless the fuel is otherwise rated using the FFAS.

- **The point of regulation (POR) for covering fuels under the cap must be the point of finished fuel product distribution, not the refinery gate as commonly proposed to date.**

Only at such a point (which is already used for fuels regulation under the Clean Air Act) is it possible to fully account for the GHG impacts of all fuels and fuel components that reach the market. While some economists may assert that the POR should be as upstream as possible, such a view reflects poor knowledge of real-world markets, particularly the transportation fuels market, where complete allowance and credit reconciliation must be done at locations sufficiently downstream to track all components of fuels that ultimately reach retail outlets.

- **This approach holds unrated biofuels competitively harmless against conventional fuels.**

Because refiners submit allowances for only the conventional fuel carbon equivalent of biofuel unless its voluntary FFAS rating shows otherwise, the relative pricing of a biofuel compared to a conventional fuel for which it substitutes would be the same as it is without climate policy in place. While a carbon cap will impact differently the production costs of different biofuels, their value in the motor fuel market does not change unless they are rated using the FFAS.

- **This approach need not replace the Renewable Fuel Standard (RFS), which can remain in place as a separate program to drive volumes of specified fuels into the market.**

The RFS mandates 36 billion gallons of renewable fuel by 2022. Depending on its composition, that would comprise 9%–13% of the 260 billion gallons gasoline-equivalent transportation fuel demand then projected after vehicle efficiency gains. Although the RFS limits GHG intensity for portions of its mandated volume, it leaves GHG emissions uncontrolled for the vast majority (roughly 90%) of U.S. transportation fuel. With the three-part approach outlined here operating under a carbon cap, the RFS would not be needed for controlling GHG emissions. It could remain in place to promote renewable fuels for reasons of energy security and economic development.

- **Use of the FFAS is voluntary, but rigorous accounting for fuels under the cap will create an incentive for fuel and feedstock providers to rate their products using the FFAS.**

Because FFAS ratings are data driven and facility specific, controversies due to disputable modeling assumptions can be minimized. While initially only producers with verifiably low-GHG production would rate their products, opportunities for market-driven growth in low-carbon fuel and feedstock production practices will motivate innovations that can be rewarded only through use of the ratings. Because no GHG reduction credit is given for unrated products, a voluntary FFAS program also avoids the need for explicit grandfathering.

- **Although informed by lifecycle analysis, FFAS rating differs from it in important ways.**

FFAS is facilities-based rather than product-based in that the basic unit of accounting is a facility (farm, forest, biorefinery, etc.) where feedstock and fuels are produced. It treats facilities as "black boxes" and so reporting a FFAS rating entails only a tally of GHG fluxes across the facility system boundary. There is no need to characterize the processes used by various facilities or to develop detailed analyses for multiplicities of feedstock-fuel "pathways" as defined by fuel cycle modelers and applied in lifecycle-based regulations such as an LCFS. The FFAS rating depends strictly on verifiable data, or facility-specific modeling based on local data, from the actual fuel or feedstock supply chain. If one element changes (e.g., if feedstock is sourced differently), then the FFAS rating will change (or be lost, for example, if an unrated feedstock is substituted for a rated feedstock).

Also, the FFAS is a protocol designed to track CO_2 uptake and uncapped GHG emissions for reconciliation with the cap while avoiding both missed emissions and double counting. In feedstock production, for example, a credit is given for additional CO_2 absorbed by the growing biomass; that value is debited by N_2O from fertilizer use but not debited for CO_2 emissions from purchased fuels that are otherwise under the cap. Allocation among co-products will be needed as will procedures to avoid double crediting with offsets programs.

- **This approach would establish a market-based GHG management system that does not entail or require explicit comparisons of fuels.**

Because FFAS ratings and the carbon cap address production facilities where GHG emissions occur rather than end products, and rely on facilities data rather than assumed processes, policy makers need not put themselves in the position of judging different fuels or fuel pathways as "clean" (or "dirty") relative to others. While those inclined to think of products as clean or otherwise may find the lack of comparisons discomfiting, such product comparisons are not necessary under a GHG management paradigm that targets production-related emissions at locations where they occur rather than at the point of product distribution. Transportation fuels are traditionally fungible and fairly undifferentiated commodities. It is unclear that differentiating fuels with a product-based metric is as important as the ultimate product price, which would reflect carbon pricing of feedstocks and other process inputs due to their coupling to the carbon market through the FFAS.

The FFAS rating will immediately (e.g., within an annual reporting period) reflect actual emissions, including the impacts of operational innovations of any type as well as changes in purchased inputs and other variables. The GHG mitigation value of bio-based fuels and feedstocks is then reflected in their price, which is in turn based on the reduction in allowance submission requirements determined by the difference between their net uncapped emissions and those of their fossil fuel or fossil feedstock equivalents. Such an approach is also consistent with the fact that it is the stationary source emissions associated with production that should be the object of attention rather than the products themselves, which can be physically identical regardless of how they are produced (e.g., corn ethanol is the same chemical as cellulosic ethanol).

- **The Land Protection Fund (LPF) would use the same specifications as proposed for international forest carbon programs, drawing on the extensive policy development work that has already gone into prescribing requirements for high-quality offsets.**

Unlike general offsets programs, the quantity of offsets purchased would not be just left up to the market. Rather, the LPF would purchase the quantity needed to fully mitigate the leakage linked to fuels. That quantity would be determined through analyses similar to those being used to assign an indirect land-use change value in lifecycle-based regulation. For funding a LPF, a variety of options can be identified that will need to be explored in subsequent discussions of this concept.

A low-carbon fuel standard (LCFS) has been proposed to address the limitations of, or to replace, inclusion of fuels in the cap. The approach outlined here avoids the added regulatory layer of a LCFS, focusing instead on ways to make the cap itself more effective.

In summary, the concepts introduced here are applicable for designing market-based policy to limit emissions and motivate technology change in the transportation fuels sector. Further analysis and discussion are needed to assess whether this approach can be developed into an effective, equitable and efficient policy for handling biofuels in the context of an economy-wide carbon cap. ■

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INTRODUCTION

Limiting greenhouse gas (GHG) emissions to levels low enough to avoid the most dangerous impacts of global warming is a challenge for all nations and all sectors of an economy. Many recent U.S. climate policy proposals seek to limit emissions to 20% or less of current levels by mid-century. Attaining such a goal is not possible without greatly reducing the net global warming impact of energy supply, which is today largely fossil-based. Reducing demand, whether by energy efficiency or by changing structural factors that underpin demand, is also crucial, and developing measures to cost-effectively and equitably accomplish such changes is a longstanding challenge of energy policy. The challenge for the transportation sector is as daunting as any.

Because the cumulative atmospheric GHG burden must be controlled to limit damage to the climatic system, the path of annual emissions is just as crucial as the long-term target. Moreover, U.S. targets must be considered in the context of a cumulative global carbon budget. International policy is necessary and effective mechanisms must account for the interconnected nature of the global economy. Thus, policies must consider emissions leakages and induced effects, particularly changes in the biosphere, that can affect cumulative net GHG emissions for many years.

For perspective, estimated total U.S. GHG emissions were 7,260 Tg[*] in 2005; net emissions were roughly 6,400 Tg after accounting for domestic land-use change and forestry sinks.[1] Figure A-1 (appendix) gives a breakdown of the U.S. GHG inventory with an additional level of disaggregation for the transportation sector, which accounted for 28% of U.S. GHG emissions in 2005. As commonly conceived, a GHG ("carbon") cap would cover the majority of the inventory and seek to progressively limit emissions by requiring entities in capped sectors to hold and redeem emissions allowances, the total of which cannot exceed the cap over a given compliance period.

Policy context

For the transportation sector, U.S. energy policy to date has largely relied on policies to expand and secure access to oil supplies, improve vehicle fuel efficiency, and promote the development and use of alternative fuels. Extensions of these policies form the basis for most thinking on transportation-climate policy.[2] From an environmental protection perspective, however, such approaches have limitations. Quantitatively, this can be seen in the gap that remains between the GHG emissions levels implied by recently adopted energy policies and the levels needed for climate protection. Figure 1 (next page) compares two forecasts of U.S. fossil-related CO_2 emissions, before and after the Energy Independence and Security Act (EISA 2007), to a capped emissions path leading to a CO_2 emissions level in 2050 that is 83% lower than the 2005 level.[3] This chart is meant merely to be illustrative and so it shows only CO_2 emissions, not all greenhouse gases (CO_2 was 84% of total U.S. CO_2-equivalent GHG emissions in 2005).

Alternative fuels policies have evolved into policies for promoting new fuels through regulation of full fuel cycle GHG impacts. Such approaches use lifecycle analysis (LCA) to discriminate fuels, as recently adopted for California's Low-Carbon Fuel Standard (LCFS) and proposed federally in the EISA Renewable Fuel Standard (RFS), which prescribes LCA-based GHG reduction thresholds for various categories of fuel. Although LCA requirements represent a marked departure from traditional approaches to environmental regulation, many policymakers seem comfortable with the simple-sounding notion of regulating fuels by lifecycle GHG impact (or "carbon footprint" as it is

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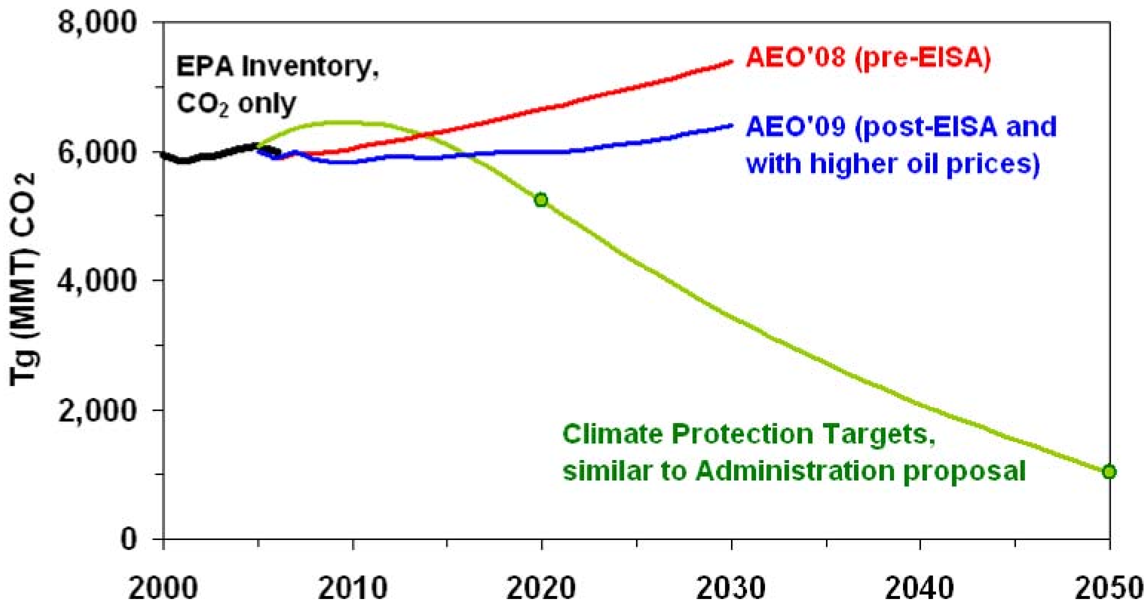
[*] GHG emissions are given here in teragrams (Tg) CO_2-equivalent; 1 Tg (10^{12}g) = 1 million metric tons (MMT). Note that 1 $TgCO_2$ = 44/12 (3.667) TgC for comparison to values on a carbon (rather than CO_2) basis.

Figure 1. Recent projections of U.S. fossil CO_2 emissions compared to climate-protection targets such as those proposed by Obama Administration



Source: EPA (2008); EIA (2008a, b); climate protection targets are an interpolation of reductions below the 2005 level by 14% in 2020 and by 83% in 2050 (shown as circles on green curve), allowing emissions to rise through 2010 at 1.2% per year (average 1990-2005 rate derived from EPA 2008).

colloquially called). In its notice of proposed rulemaking (NPRM) for the RFS, the Environmental Protection Agency notes that, "To EPA's knowledge, the GHG reduction thresholds presented in EISA are the first lifecycle GHG performance requirements included in federal law."[4] LCA-based regulation is sweeping in its claims for effectiveness because at least in theory, it accounts for all relevant impacts, e.g., as seen in its EISA definition (below). Although the literature on LCA results for fuels is extensive, the literature on LCA as a literal basis for policy is actually quite limited.[5]

Cap-and-trade, in contrast to LCA, focuses on discretely measurable emissions from specific sources, using what can be termed annual basis carbon ("ABC") accounting protocols, and is designed to capture the majority of emissions while recognizing that measurement challenges and other considerations may rule out complete coverage. Most cap-and-trade proposals follow U.S. EPA GHG inventory conventions in covering major stationary and mobile sources. The resulting tally includes the majority of fossil-based CO_2 emitted during energy consumption (see Figure A-1). Excluded are industrial feedstocks and non-fossil emissions from agriculture and forestry. A fossil-based cap covers emissions from energy that agricultural users purchase from covered sectors, such as electricity and fossil fuel emissions above specified thresholds. But it does not cover, for example, nitrous oxide (N_2O) emissions or the CO_2 associated with changes in soil management and land-use. Moreover, the direct, inventory-based ABC accounting used to implement a cap is strictly static, including neither economically induced effects nor temporal effects that might reflect (perhaps on a discounted basis) future GHG fluxes.

Cap-based policy seeks to manage and limit GHG emissions through a carbon accounting system using allowance tracking and transactions, resulting in an economically efficient system.[6] Including transportation fuels under the cap is necessary for the integrity of an economy-wide program because the sector's emissions are too large to leave unconstrained. However, it is not sufficient because of the complex nature of the multiple markets that comprise the sector. While this paper does not review all of the reasons why complementary policies are needed for transportation,[7] one major concern is that fossil-based cap misses a substantial portion of emissions, particularly from biofuels. Although similar issues arise for electricity and gaseous fuels derived from biomass, this paper focuses on liquid biofuels and biomass-based feedstocks used to produce liquid fuels.

Biofuels such as ethanol and biodiesel have been promoted in the United States, Brazil, Europe and elsewhere as a solution to problems associated with the dependence of transportation on petroleum fuels. Biofuels also have policy support due to the economic benefits their production offers to rural communities. Because they are considered renewable, that is, able to be replenished on an ongoing basis as opposed to depleted like fossil fuels, biofuels have also enjoyed political support as part of a vision for a "sustainable," "energy independent," or "fossil-free" energy future.

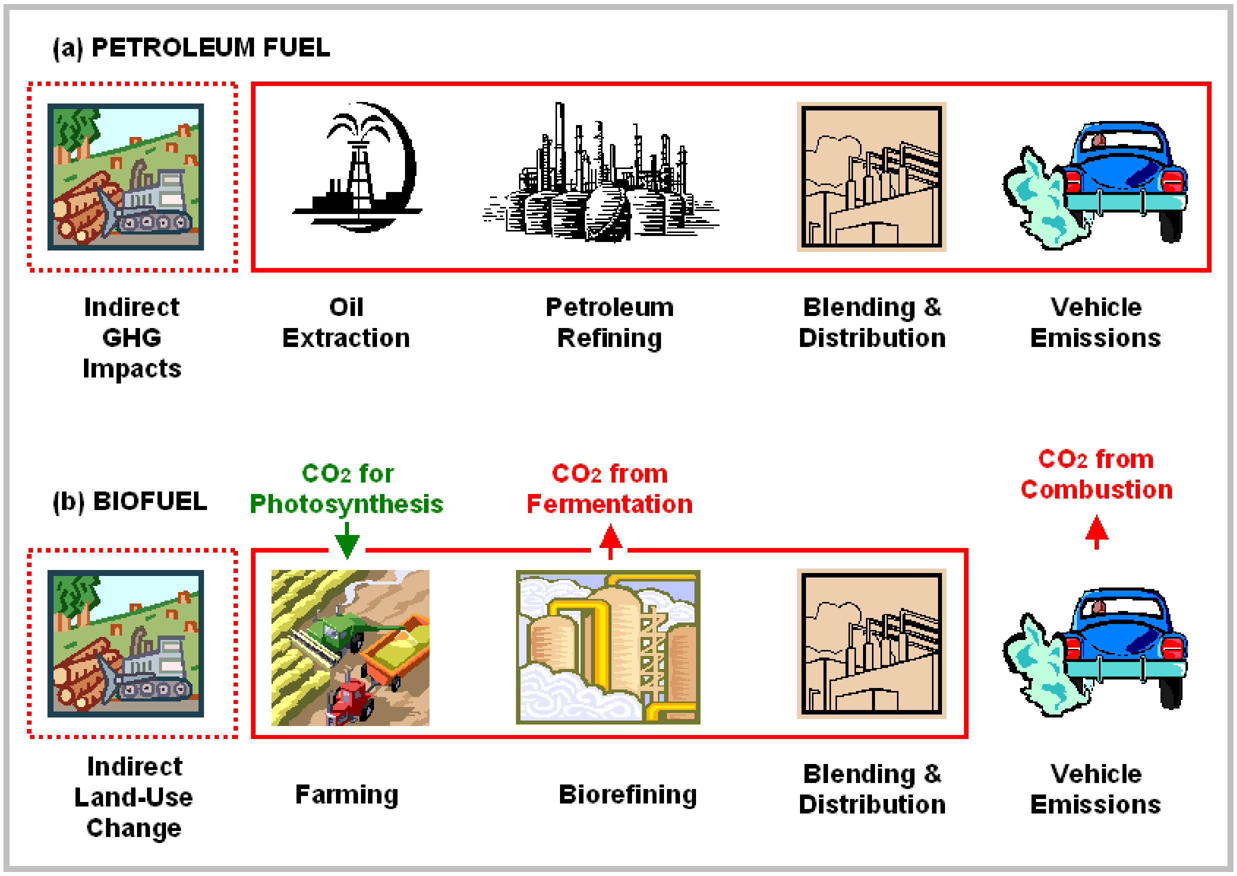
The renewability shortcut

A common premise regarding renewable biomass-based energy resources is that, because of its recent biogenic origin, CO_2 from their combustion does not cause a net increase in atmospheric GHG concentrations. Although the net energy and emissions impacts of biofuels have long been debated, official GHG inventories as well as most energy and climate models use this "renewability shortcut," the simplifying assumption that biofuels *per se* emit no net direct CO_2 emissions.[8] In this context, *direct* means emissions from the point of combustion or other end-use process that releases CO_2 derived from the molecular (chemical) carbon contained in the fuel itself.

In addition to the combustion emissions from a renewable fuel, biogenic CO_2 is emitted in other ways, such as the CO_2 released during fermentation of sugars into alcohol. Some biofuels, such as fatty acid methyl ester (FAME) biodiesel, may contain both biogenic and fossil carbon if some of their inputs are fossil derived. Other processes can involve direct or indirect biogenic CO_2 emissions and significant portions of biogenic carbon end up in non-fuel co-products, such as feed components. Although lifecycle models often tally biogenic carbon internally by computing biofuel combustion CO_2 and then netting it out by an assumed equal CO_2 uptake, this approach still leaves out biogenic CO_2 emissions as far as results are concerned and conveniently enables analysts to avoid complete tracking of biogenic CO_2 regardless of its form and fate.

The renewability shortcut has shaped policy analysis and thinking to date.[9] Both traditional lifecycle analysis (LCA) approaches (as proposed for fuels GHG regulation) and requirements for GHG emissions allowance tracking (as proposed for cap-and-trade policy) use it and so exclude direct CO_2 emissions from biofuels. For example, EPA states that its tailpipe emissions values for ethanol exclude CO_2 emissions, "as these are assumed to be offset by feedstock carbon uptake," in its analysis for the proposed RFS rule.[10] Figure 2 (next page) illustrates the situation, comparing the system boundaries as used in full fuel cycle models such as GREET for a fossil fuel and a biofuel.[11] This shortcut implicitly assumes that the CO_2 reduction due to substituting a biofuel for a fossil fuel is completely *additional* and incurs no *leakage* in a carbon accounting sense.[12] An action claimed to reduce GHG emissions is additional if it truly yields net GHG reduction over and above what would have occurred if the action were not taken. Leakage is a shift of emissions to another location (or time) that negates some or all of the GHG reductions an action claims to achieve.

Figure 2. System boundaries as commonly defined for transportation fuels lifecycle analysis and GHG inventories



N.B. This diagram is deliberately simplified to highlight key factors for discussion. A full depiction of GHG fluxes would need to address many other details including soil carbon and N_2O, co-products and other inputs/outputs of both bio- and fossil-based fuel production.

Carbon accounting issues for fuels

For a fossil fuels, lifecycle analysis uses a complete, intact "well-to-wheels" system boundary as far as direct effects are concerned. For biofuels, however, the system boundary effectively excludes the "wheels" even though it is still called "well- (or field-) to-wheels" analysis. As also shown in Figure 2, another gap in the system boundary is for biogenic CO_2 released during biofuel production (e.g., in fermentation or combustion of biomass for process heat). The CO_2 that enters the system through absorption during photosynthesis by growing biomass is, of course, the initial gap in the system boundary on which the shortcut is premised.

A problem with this premise is the fact that land for growing either bioenergy feedstocks or any use of biomass (food, feed, fiber, forest products, etc.) is globally finite. Moreover, "unused" land -- land that is largely untouched, fallow or reverting to a "natural" (non-human-managed) state, and particularly unused land suitable for agriculture or forestry -- would most likely be otherwise occupied by growing plants and therefore absorbing carbon anyway. Globally speaking, a net benefit of avoided atmospheric CO_2 buildup exists only if additional net absorption occurs over the entire biosphere. However, this is unlikely to be the case because scientific assessments clearly indicate that on a global basis land-use change, mainly tropical deforestation, is a large net source of emissions, contributing roughly 20% of total anthropogenic GHG emissions.[13]

Recognizing these facts means that the CO_2 reductions implied by using the renewability shortcut are not fully additional. Moreover, even if they appear additional on a local basis, leakage from economically induced effects may prevent the reductions from being fully additional on a global basis. Leakage can occur anytime a climate mitigation policy is incomplete either spatially or temporally.[14] The question is therefore about the extent to which net GHG emissions are reduced when diverting some of the growing biomass -- which would soon see its recently absorbed carbon returned to the atmosphere as CO_2 via metabolism or other energy-releasing process -- to displace fossil fuel as a source of energy.

While the focus here is on the problems it raises for climate policy, this same concern is closely related to the "food vs. fuel" debate that follows from the ripple effect created by the integration of the global agricultural and energy sectors, for which biofuels provide one but not the only nexus.[15] The renewability shortcut also poses problems when attempting to apply analyses that use it for the design of regulations or market incentives that match accountability for fuel-related GHG emissions to parties who have the most control over different aspects of the emissions.

The same problem arises in official projections of energy-related CO_2 emissions, such as those given in DOE's *Annual Energy Outlook,* which also excludes biogenic carbon from its tallies. The result is a potentially misleading picture of inferred GHG emissions reductions. The renewability shortcut also presents a challenge for reconciling biofuel GHG emissions with a carbon cap in a manner that will not just "account for" emissions, but will in fact ensure that any assumed reductions are additional while avoiding barriers of incomplete information and providing the supply chain accountability needed for a well-functioning carbon market. Since it is not possible to establish a global carbon management policy all at once, the challenge is that of how to appropriately reward locally efficient GHG reduction options, such as biofuels might be, in a way that does not create perverse incentives because of incomplete global accounting.

Indirect GHG emissions impacts

A key issue is that of how to handle indirect or economically induced GHG emissions which fall outside of a supply chain that is traceable through specific commercial transactions. In Figure 2, indirect impacts are shown with a dotted boundary line. While real, such emissions represent effects outside the direct control of most if not all entities in a fuel supply chain. Therefore, questions of attribution and responsibility arise that have led to ongoing discussions regarding how public policy should handle indirect impacts.

However indirect effects are handled, comparing fuels according to their lifecycle impacts "requires a clear and consistent definition of the system boundary both in terms of geography as well as the scope of effects that are compared."[16] While such effects have been highlighted for biofuels, petroleum fuels also have indirect effects, including the GHG emissions during oil exploration and associated land-use impacts, deforestation and opening up of forested areas due to road and pipeline construction land, market effects from co-products such as residual oils and asphalts, as well as the emissions from military activity to protect and secure petroleum supplies.

For biofuels, the induced impact of greatest concern is indirect land-use change (ILUC). When a biomass feedstock is grown on arable land, it competes with land used for other purposes including forest and grassland that is holding carbon. Increased demand for agricultural production -- whether for foodstuff, livestock feed or biofuel -- raises commodity prices, which in turn stimulates conversion of additional land to agricultural production.[17] The induced land-use change can occur in areas remote from the source of demand and similar effects can occur when withdrawing land from production, as in conservation reserve programs. Although the chain of effects can be complex and quite indirect, of particular concern is the impact on tropical forests which are under ongoing pressure for numerous reasons related to population and income growth.[18] Loss of forest and other cover vegetation and soil disturbance during land conversion cause a substantial release of carbon to the atmosphere. Globally, such deforestation and forest degradation (largely in the tropics) account for roughly 20% of anthropogenic GHG emissions.[19]

The issue of trade-offs in land use and their net impact on GHG emissions is profound. Arable land is a limited resource and the ecological benefits -- including carbon sequestration -- of native forests and grasslands are substantial. Therefore, a major challenge for GHG mitigation policy is balancing the global use of land as protected ecosystems against its use for producing biomass to displace fossil fuels.[20] Achieving this balance will require careful consideration of the circumstances of land use and agricultural production. An implication is that climate policy should be designed to reward the most beneficial uses of land from a net GHG limitation perspective, which practically speaking can only be evaluated within the broader context of the many other factors that shape energy, agricultural and land-use policy both domestically and globally.

Both the RFS as expanded by EISA (2007) and the LCFS as promulgated by CARB (2009) require significant indirect impacts to be addressed. For purposes of qualifying categories of renewable fuel other than those from existing facilities, EISA specifies the following definition:

> (H) LIFECYCLE GREENHOUSE GAS EMISSIONS.—The term 'lifecycle greenhouse gas emissions' means the aggregate quantity of greenhouse gas emissions (including direct emissions and significant indirect emissions such as significant emissions from land use changes), as determined by the Administrator, related to the full fuel lifecycle, including all stages of fuel and feedstock production and distribution, from feedstock generation or extraction through the distribution and delivery and use of the finished fuel to the ultimate consumer, where the mass values for all greenhouse gases are adjusted to account for their relative global warming potential.[21]

As of this writing, however, the climate bill currently pending in Congress (ACESA 2009) proposes to exclude overseas ILUC from the RFS regulations, stipulating:

> "(A) EXCLUSION FROM REGULATORY REQUIREMENTS REGARDING LIFECYCLE GREENHOUSE GAS EMISSIONS.—Notwithstanding the definition of 'lifecycle greenhouse gas emissions' in paragraph (1)(H), for purposes of determining whether the fuel meets a definition in paragraph (1) or complies with paragraph 10 (2)(A)(i), the Administrator shall exclude emissions from indirect land use changes outside the renewable fuel's feedstock's country of origin.[22]

ACESA then calls for a National Academy of Sciences study to assess issues related to the indirect GHG emissions impacts of transportation fuels, followed by a joint EPA-USDA determination of whether and how such impacts should be addressed in the RFS regulation.

The Executive Order establishing the California LCFS stipulated that it "…shall be measured on a full fuel cycle basis… ."[23] Although this instruction is not as specific as the federal law, CARB has broad discretion over how to develop its authorized regulations. The LCFS implementation proposal cites the EISA definition and other considerations in electing to include indirect impacts when calculating lifecycle-based Carbon Intensity (CI) values for fuels. CARB states that it identified only one indirect effect that generates significant quantities of GHGs, specifically land-use change effects "triggered by a significant increase in the demand for a crop-based biofuel."[24]

This paper does not address the ILUC issue in the context of regulatory policies that use lifecycle analysis such as the RFS or LCFS. Instead, it examines other mechanisms for addressing indirect impacts, namely, a more careful specification of allowance submissions requirements for fuels under a cap and a Land Protection Fund. The rationale is that because ILUC is economically induced at a global ("macro") level, it might be best addressed by an approach that also operates at a macro level, using a cap-based market mechanism to minimize the adverse economic signal and create a price signal that counter-balances the remaining biofuel-related price pressures causing the land-use changes of concern, particularly tropical deforestation.

Overview of paper

Some of the emissions associated with biofuel production are included in traditional inventory-based modeling but others are not. Emissions from purchased fossil fuels used in growing biomass feedstocks and in biorefining are tallied in their respective supply (e.g., electricity) or end-use (e.g., diesel fuel) sectors. Agricultural emissions of N_2O and CH_4 are tallied in that portion of the EPA inventory, but are not reflected in the fossil-CO_2 only emissions reported in the Energy Information Administration (EIA) *Annual Energy Outlook*. However, indirect emissions are not tallied in either place, and neither are direct emissions associated with upstream processes that might occur overseas for either fossil or biofuels.

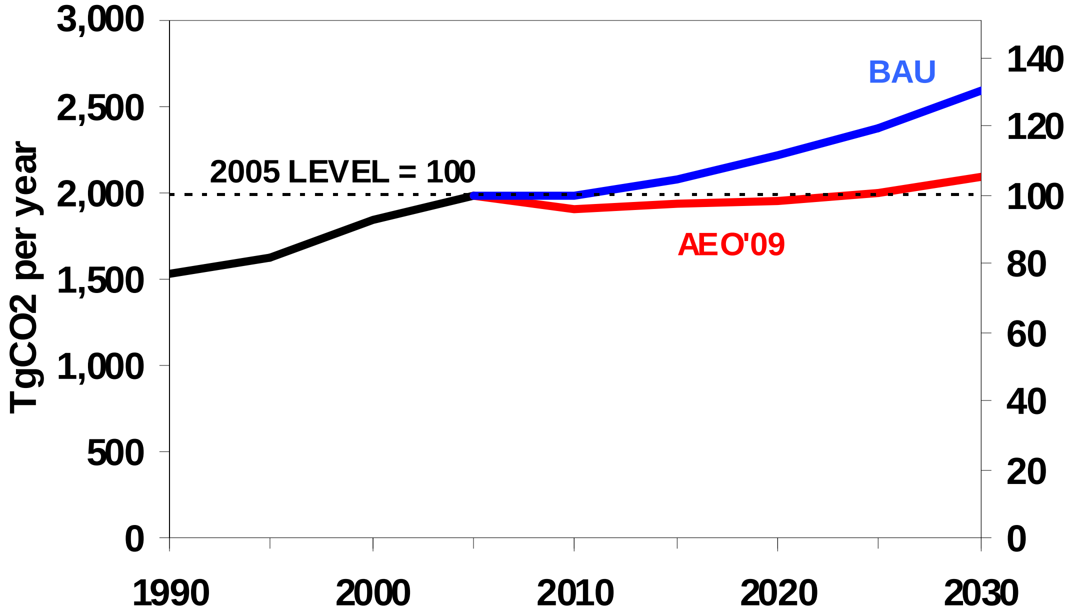
The Background Analysis section of this paper reviews available information in order to characterize the emissions likely to be missed under carbon-cap policies as proposed to date. The bottom line is that emissions reductions as appear to be projected by EIA (as seen in the "post-EISA" curve of Figure 1) are not an accurate reflection of total impacts because they fail to reflect all of the GHG emissions associated with transportation fuel use.

The balance of the paper then explores whether a set of policy mechanisms can be defined that retains the power of a cap-driven market while sufficiently addressing emissions missed by a fossil-based cap. If such mechanisms can be defined, it may not be necessary to rely on an additional regulatory program, and an integrated policy approach might then both provide effective GHG management and drive beneficial technology change in transportation fuels in a manner consistent with limiting GHG emissions to climate-protective levels.

BACKGROUND ANALYSIS

To fully examine the extent of transportation fuel-related GHG emissions missed by a fossil-based cap would entail parsing out capped vs. uncapped emissions throughout the fuel lifecycle, with attribution to potentially regulated entities as opposed to the stylized fuels production pathways on which LCA models are based. That task would be a challenging for a variety of reasons. One is simply that GHG emissions from fuel production are not yet regulated and the requisite reporting is not in place. Moreover, available information is largely based on LCA methods whose analytic foundations were never really designed for emissions tracking,[25] but rather were based on process energy utilization models that entail multilayered assumptions and report aggregate results for abstract production pathways. Such results are difficult to disentangle for addressing the questions

Figure 3. U.S. transportation sector end-use CO_2 emissions with business-as-usual (BAU) projection compared to EIA's Annual Energy Outlook (AEO) 2009, with scale relative to the 2005 level of 1,985 $TgCO_2$/year



posed here.[26] Nevertheless, available information and a review of results from existing fuel lifecycle analyses enable construction of a sketch model of the situation.

Thus, this analysis approximates the GHG magnitudes involved by using a simplified model of U.S. transportation energy use in order to help think through options for coupling a fossil carbon cap to the transportation fuels sector. Working from recent editions of EIA's *Annual Energy Outlook* (AEO), which projects energy use and direct, fossil-only CO_2 emissions through 2030, a range of estimates for the relative magnitude of emissions missed by a cap is given in Table 1. For ease in conveying relative importance, the table normalizes transportation sector direct CO_2 emissions to their 2005 level, so that the value 100 scales to the 1,985 $TgCO_2$ (annual) estimated for 2005 by EIA.[27] Figure 3 shows AEO projections with the scaling levels and historical data since 1990.

Transportation sector CO_2 emissions

Table 1 summarizes the relative magnitudes of emissions missed by a cap under various assumptions; a tabulation of absolute emissions levels is given in the appendix for reference. The first line (A) of Table 1 lists hypothetical targets for the sector proportional to economy-wide cap targets similar to those articulated in President Obama's 2009 budget proposal.[28] Although a market-based national climate policy would dictate only economy-wide, not sector-specific targets, proportionality is a useful point of reference for comparing how well sector policies limit emissions relative to economy-wide targets and timetables.

The second line (B) gives a business-as-usual (BAU) trend estimated without recently enacted energy policies such as vehicle efficiency standards and the RFS. This BAU case (also plotted in Figure 3) accounts for a near-term slowdown in economic growth and also reflects the EIA's recent, substantial upward assumptions for future world oil prices. Compared to the AEO 2008 average of

Table 1. Sketch model of U.S. transportation sector GHG emissions missed by a cap

Line	Scenario	2000	2005	2010	2020	2030
A	Cap targets (similar to Obama administration's)		100	--	86	57
B	BAU trend (fixed vehicle efficiency)	93	100	100	111	130
C	Vehicle efficiency gains only (CAFE, etc.)		100	100	105	114
D	Apparent emissions, as projected by DOE		100	96	98	105
	Reductions from biofuels					
E	apparent [C-D]			4.0	6.1	9.0
F	actual - Low emissions case [(1-L)*E]			0.3	1.6	3.0
	- High emissions case			-3.5	-2.8	-3.0
G	Actual emissions - Low [C-F]			100	103	111
	- High			103	107	117
H	Biofuel emissions missed by cap - Low [G-D]			3.7	4.5	6.0
	- High			7.4	8.9	12.0
I	Imported refined products		6	5	4	4
J	Imported heavy crudes		3	5	8	11
K	Total emissions missed by cap - Low [H+I+J]			13	17	21
	- High			17	22	27
L	Biofuel GHGs relative to conventional fuel					
	Low GHG intensity			0.94	0.73	0.67
	High GHG intensity			1.87	1.47	1.34

Source: Derived from DOE (EIA) AEO 2008 and 2009, Table A18, normalized so that the 2005 level = 100, for transportation sector direct CO_2 emissions; see Table A-1 in appendix of this paper for details.

$57 per barrel, AEO 2009 projects an average $108 per barrel for the 2010-2030 period. Line B reflects impacts on travel demand but not on vehicle efficiency (which is given in Line C). Even without efficiency gains, growth in transportation sector direct CO_2 emissions is relatively slow (1.1% per year) compared to earlier projections, reaching levels of 111 by 2020 and 130 by 2030 relative to a 2005 level of 100.

The third line (C) of the table reflects the projected impact of vehicle efficiency improvements, due to both Corporate Average Fuel Economy (CAFE) standards and higher fuel prices, but not the RFS. This case is derived from AEO 2009 energy use projections while assuming a fixed transportation fuel end-use carbon intensity, i.e., backing out the reduction in carbon intensity implied by EIA's failure to count renewable fuel emissions in the transportation sector tally. The result is that efficiency gains alone hold growth in transportation sector direct, fossil-only CO_2 emissions to 5% above the 2005 level by 2020 and 14% by 2030, for an average 2005-2030 growth rate of 0.5% per year.

Line D provides the relative CO_2 emissions levels corresponding to EIA's actual AEO 2009 projections (EIA 2008b), including both efficiency gains and the displacement of petroleum fuels by renewable fuels under the RFS. Based EIA's projections, actual renewable fuel use reaches only about 28 billion gallons by 2022, equivalent to 30 billion gallons in terms of RFS credits and so short of the 36 billion gallon mandate.[29] It grows over the remainder of that decade so that by 2030 renewable fuel use reaches 36 billion gallons (projected actual volume, corresponding to 39 billion RFS credits). These RFS volumes result in an apparent decrease in transportation sector CO_2 emissions to below the 2005 level over 2010-2020 and then small growth to a relative level of 105 by 2030, as shown in Line D of Table 1 and AEO'09 curve in Figure 3.

We characterize the emissions reductions implied in Line D as *apparent,* in contrast to EIA's unqualified reporting of significant CO_2 emissions reductions due to a shift "to fuels that are less carbon-intensive or carbon neutral."[30] As in EPA's GHG inventory, EIA's use of the "renewability shortcut" omits most biofuel emissions from their transportation sector tabulations and so assumes that the CO_2 emissions reduction from replacing fossil carbon by biogenic carbon is fully additional. Although emissions from fossil fuels used in biofuels production are counted in EIA's overall fossil CO_2 tallies across sectors (including, e.g., diesel fuel for farming biofuel feedstocks), non-fossil CO_2 GHG impacts are not counted and neither are any overseas leakage or indirect effects.

Nevertheless, these apparent reductions still leave transportation CO_2 emissions at a level higher than the illustrative climate-protective levels such as those in Table 1, Line A. (Again, this illustration is not meant to suggest proportional targets across sectors, but only to suggest the limitations of existing energy policies for addressing climate.) It should also be kept in mind that energy forecasts often change greatly from year to year, as seen in the marked changes from EIA's final, post-EISA AEO 2008 to its early release AEO 2009 projections. This forecasting variability is tied to varying assumptions about future economic growth, energy resources and market volatility.

Biofuel emissions missed by a cap

As remarked above, it is difficult to disentangle capped from uncapped emissions in published analyses of GHG emissions from biofuels. However, it is possible to make a rough approximation of the range of emissions not accounted for under the transportation sector as typically tallied under cap-and-trade proposals. Some of the most significant emissions not covered by cap accounting are also the most uncertain. This concern applies both to direct emissions in a biofuel supply chain, such as N_2O from farm fields, and to indirect emissions outside of the supply chain, such as carbon fluxes from land-use change. Although such issues are very different, they both result in large uncertainties that would remain even with a more detailed analysis.

Line E of Table 1 gives the "apparent" emissions reduction from the RFS-driven expansion of biofuels use. It is the difference between the level scaled to EIA projections (D) and the level calculated on the basis of vehicle efficiency improvements alone (C). Relative to the 2005 reference level of 100, apparent reductions from the RFS amount to 4 in 2010 and rise to 9 in 2030. The 9 unit reduction represents 36% of the apparent total CO_2 reduction of 25 in 2030.

To illustrate the possible magnitude of missed emissions, we use a low-high range of assumed biofuels GHG intensity. Strictly speaking, this mixes lifecycle accounting with cap accounting. Given the uncertainties involved, however, the portion of lifecycle emissions captured by a cap (partly in other sectors) is likely to be counterbalanced, if not more than counterbalanced, by the large high-end uncertainty in uncapped emissions that some of the literature suggests are underestimated by most lifecycle tallies (including both N_2O as well as land-use change).[31] Any such assumptions admittedly beg the question of how such lifecycle analysis should be done and how it should be applied. However, the objective here is not to weigh in on how to craft LCA-based regulation, but rather to characterize the emissions accounting problem in the context of a carbon cap for the purpose of exploring mechanisms to address the gaps.

Lines L at the bottom of the table give lifecycle biofuel GHG intensity relative to petroleum fuel. The Low values are based on a straightforward application of the RFS lifecycle requirements to the mix of biofuel projected by EIA (2008b). These intensity values assume that, on average, "grandfathered" ethanol[32] has the same GHG intensity as gasoline and that compliance with the RFS lifecycle requirements is based on traditional fuel cycle analysis modeling assumptions. As projected volumes of cellulosic and other advanced biofuels increase, the projected GHG intensity of the supplied biofuel mixed declines, reaching an estimated level of 0.67 (33% average reduction in lifecycle GHG emissions) by 2030.

For an illustrative High emissions range, we simply double the Low values. In this case even by 2030 the net GHG intensity of biofuels remains higher than that of conventional petroleum fuels (meaning fuels from conventional oil, not from high-carbon fossil resources). This pessimistic picture is broadly consistent with those studies that suggest that *any* purpose-grown energy crops (including highly efficient ones) fail to yield net GHG reductions that are truly additional on a global basis in light of the constraints on productive land even with ongoing increases in yield. These High values illustrate a rough magnitude of impacts if compliance with the RFS lifecycle GHG emissions requirements fails to reflect real-world emissions by a wide margin.[33] Again, the purpose here is only to illustrate how the disparate views on biofuel emissions affect the range of emissions missed by a GHG cap based on fuels' fossil-carbon content alone. A combination of technological progress (e.g., making fuel from wastes[34]) and effective GHG management throughout the supply chain might offer a less pessimistic outcome.

Lines G provides a range of adjusted estimates of actual relative U.S. transportation sector GHG emissions impacts; these estimates can be considered as giving a more complete picture than the EIA projections of Line D. Only missed biofuel-related emissions are included in these impacts, which include any overseas component of ILUC but do not include any conventional upstream emissions either domestically or overseas. As shown in the Low-High range of Lines G, emissions do not fall below the 2005 level and by 2030 range from 11%–17% higher than the 2005 level, rather than just 5% higher as projected by EIA.

Upstream fossil emissions missed by a cap

The largest part of non-end-use combustion (i.e., non-"tailpipe") emissions associated with conventional transportation fuels is covered in the industrial sector by a carbon cap's application to major stationary sources such as refineries and other facilities involved in producing and distributing gasoline, diesel, aviation and other transportation fuels. As long as the facilities are in the United States, they fall under the cap (unless their emissions fall below a regulatory threshold, such as 25,000 tons of CO_2). Thus, the increased GHG emissions that come from, say, domestic refining and upgrading of imported heavy crudes, or from domestic oil shale and coal-to-liquids processing, would not be missed by a cap.

The emissions missed are those occurring overseas in countries without a carbon cap in place. Currently, the largest portion of such emissions is that associated with imported refined products, such as gasoline or gasoline components imported from refineries located in Venezuela, for example. Gasoline imported from refineries covered under the European Emissions Trading System (EU-ETS), on the other hand, is not a source of missed emissions in terms of cap-based accounting. Missed upstream emissions of growing concern are those associated with synthetic crude or finished fuel products derived from Canadian oil sands. These emissions will remain inadequately accounted for unless Canada adopts a carbon cap that covers their production facilities.

Lines I and J of Table 1 provide estimates for imported refined products and imported heavy crudes, respectively, of the relative GHG emissions that would be missed by a cap.[35] As of 2005, the levels were 6 for refined product imports and 3 for heavy crude imports, relative to a reference emissions level of 100. EIA projects refined products to decline through 2030 due to expansions in U.S.-based capacity and a reduction of excess overseas refining capacity available for export to the United States as global demand for transportation fuels grows. On the other hand, the reliance on heavy crudes and unconventional resources is expected to grow. As a result, by 2030 the "high-carbon" fossil resource portion of missed emissions could grow to a level of 11 relative to the overall U.S. transportation sector base emissions level of 100 in 2005.

Summarizing missed emissions

Lines K (Low and High) of the table summarize an illustrative range for GHG emissions associated with U.S. transportation fuel demand that would be missed by a fossil-based cap-and-trade program as commonly proposed to date. These values are the sum of the estimates for imports of both conventional refined products and high-carbon crudes plus the estimates for biofuels.

In 2020, the level of missed emissions ranges from 17 to 22 relative to an apparent (end-use, fossil-carbon only) emissions level of 98 (Line D) implied by an unqualified interpretation of EIA's *Annual Energy Outlook*. By 2030, the range of missed emissions is 21 to 27 relative to a projected end-use, fossil-only level of 105. Of these missed emissions, the larger portions are still those related to fossil resources. The relative range of biofuel-related emissions missed by the cap in 2030 is 6–12, or 29%–44% of the of 21–27 total relative emissions level.

Translating these relative levels back to tons of CO_2 (recalling the reference level of 1,985 $TgCO_2$ annual transportation sector emission in 2005) implies ranges of 342–430 $TgCO_2e$ in 2020 and 427–546 $TgCO_2e$ in 2030. These values can be compared to the EIA projections of 1,955 $TgCO_2$ in 2020 and 2,088 $TgCO_2$ in 2030, respectively. For 2020, an illustrative, proportional climate-protection target for the sector as shown in Figure 1 would require reductions of 500 $TgCO_2e$ relative to a trend reflecting neither vehicle efficiency improvements nor nominal biofuel reductions. Referring back to Table 1, missed emissions amount to 68%–86% of the reductions relative to the BAU (fixed efficiency) trend in Line B needed to meet the illustrative targets in Line A for 2020. Thus, the total GHG emissions associated with U.S. transportation fuel use but missed under a cap-and-trade policy as commonly proposed are large and significant relative to the targets and timetables being considered for national climate legislation.

The legal and administrative status, in terms of either domestic or international policy, of the different components of missed emissions varies. Some can be considered forms of leakage; some would be captured in other capped domestic or international sectors; some occurs in sectors such as agriculture that are not being considered for inclusion under a cap. Three general approaches come to mind for ensuring that missed emissions are addressed: (1) lifecycle-based regulation; (2) a comprehensive system of direct regulation (e.g., directly including all biofuel and biofeedstock production under the cap); and (3) a more careful specification of how to apply cap-and-trade to transportation fuels. In all cases, attention would be needed on how to handle cross-border components of emissions. This paper explores Option (3), which we call "Carbon Management for Transportation Fuels," integrated into a cap-and-trade program with mechanisms for addressing the gaps in traditional carbon cap accounting.

CARBON MANAGEMENT FOR TRANSPORTATION FUELS

A GHG cap as commonly defined in terms of fossil carbon content would establish measurement-based carbon (meaning GHG) management for the majority of emissions now coming directly from the transportation sector itself. These emissions are largely the CO_2 from tailpipes. Upstream emissions (e.g., at refineries) from domestic fuels production would be covered as stationary sources under the cap. Extending carbon management to uncovered (that is, uncapped) fuel-related GHG emissions entails focusing on both direct and indirect emissions throughout the supply chain and ensuring that, taken together, the prescribed policy mechanisms address all GHG impacts.

Because agriculture is excluded from the cap and the agriculture sector is a net emitter of greenhouse gases (directly accounting for 8% of the U.S. GHG inventory), on a *prima facia* basis biofuels from *average* agricultural practice result in GHG emissions even if biogenic carbon and indirect effects are not counted. What is not known how the net GHG emissions from biofuels compare to those from fossil fuels. While fully resolving this question is a challenge, biofuels have already come into use for other reasons. Therefore, it is crucial for a fuels carbon management policy to account for biofuel GHG emissions while mitigating any associated leakage.

Cap-based accounting

An anchor for such a policy is a cap-based accounting protocol that credits only feedstocks, fuels and fuel components rated as having net uncapped GHG emissions lower than the direct CO_2 emissions of conventional fuel. This crediting would be done when determining the number of allowances that refiners submit for the fuel they distribute. Options include requiring refiners to submit allowances either for the molecular carbon content or, as a close approximation, the fossil-fuel energy equivalent carbon content, of all fuel they distribute except to the extent that it is rated as having lower net GHG emissions from *uncapped* sources throughout its supply chain according to the Fuel and Feedstock Accounting Standard (FFAS) elaborated below. The approach outlined here uses the fossil-fuel energy equivalent convention; although molecular carbon content is scientifically more precise, the difference is small and can be considered a policy judgment call.

If based on fossil fuel energy equivalence, this allowance submission requirement does not change the competitive position of biofuels already in the market, in terms of their pricing relative to fossil fuels they displace, from what it is today without a carbon cap in place. Currently, neither biofuel nor fossil fuel is exposed to a price signal from the cap. If allowances are submitted for only the conventional fuel carbon equivalent of biofuel, this aspect of market advantage or disadvantage remains unchanged, so that biofuel fuel producers are held harmless competitively relative the situation they face under current policy. Of course, a cap will differentially impact the production costs of all fuels, so market conditions do change overall.

In this design, the FFAS rating is needed only to cover emissions not otherwise covered by the economy-wide cap. Thus, the object of the ratings is not *comparison* of fuels and feedstocks, but rather *accounting* for emissions in the context of a GHG management system integrated into the cap. The value of avoided emissions ("price of carbon") will then motivate reductions throughout the managed system. Thus, the FFAS is not a fuels performance standard (such as a LCFS) but rather an accounting standard that closes the gaps in GHG accounting that occur in cap-and-trade policy as typically proposed to date. In general, FFAS would follow a principle of accounting for all impacts "reasonably attributable" to producers of fuels and feedstocks, as well as other applicable GHG-related accounting principles.[36]

Distinct roles for attributional vs. consequential methods

In this regard, the FFAS approach is similar in scope to *attributional* LCA, which restricts system boundaries to "flows physically connected to the product under study" and is "static" in that "dynamic processes are not considered," with no attempt made "to account for price variations, changes in demand or technological improvements."[37] Attributional LCA contrasts with *consequential* LCA, which models system dynamics and "is based on a system-wide approach where system boundaries are expanded [to] evaluate all of the changes in a system as a consequence of a decision."[38] Consequential LCA is needed to incorporate ILUC into a policy that requires the use of a complete lifecycle analysis, as do the EISA RFS requirements and California's LCFS.

Although consequential LCA is clearly valuable for scientific assessments and for informing policy development, it is less clear that it is appropriate for literal application in regulations or standards. Because it runs the risk of attempting to hold parties responsible for impacts well beyond those that reasonably can be attributed to their own actions, in the fuels GHG management approach outlined here consequential LCA is restricted to defining system-wide ILUC mitigation requirements and a strictly attributional method (the FFAS) is used for defining producer-specific requirements.

Thus, the FFAS approach entails measurement-based GHG balances for each entity in the supply chain. Unlike the use of the renewability shortcut in LCA, biogenic carbon uptake and emissions are both explicitly carried on the balance sheets. A negative carbon value is tallied at feedstock production entities (farms and forests) where CO_2 for plant growth is absorbed from the atmosphere. That value is then added to the positive GHG fluxes associated with the feedstock production to yield a net carbon balance value to which the produced biomass is rated. These fluxes would be based on verifiable data (such as known characteristics of reported inputs) or third-party verified, facility-specific practices (such as fertilization methods that lower N_2O emissions).

Most biomass presumably would be rated to a negative carbon value (credit) using this direct accounting, but the magnitude of the credit will be less than the quantity of absorbed CO_2 unless perfectly zero-net-GHG growing practices are used. However, as noted in the earlier discussion of the renewability shortcut, leakage issues remain and must be addressed by other mechanisms, such as the Land Protection Fund (LPF) outlined here or alternative approaches that might be developed based on carbon offsets accounting.

Carbon accounting at point of finished fuel distribution

Regardless of the mechanisms used, a critical point of accounting is where finished liquid fuel products are distributed for sale. This is the lowest point in the supply chain where various fuel components are blended prior to distribution to retail outlets (often termed the point where fuel suppliers "break bulk"). Only at such a location in the system is it possible to fully account for the different GHG impacts of biofuels or bio-based fuel components being blended with fossil-based fuels and blend stocks for subsequent distribution to retail outlets.[39]

EPA's expansive definitions of *refinery* and *refiner* in existing regulations seem well suited for specifying the point at which net GHG impacts of biofuels can be reconciled against the fossil carbon content of conventional fuels that they displace. Such a point of regulation is being considered for the lifecycle accounting under the RFS. The relevant definitions are:

40 CFR 80.2 (Definitions.)[40]

> (h) Refinery means any facility, including but not limited to, a plant, tanker truck, or vessel where gasoline or diesel fuel is produced, including any facility at which blend stocks are combined to produce gasoline or diesel fuel, or at which blend stock is added to gasoline or diesel fuel.
>
> (i) Refiner means any person who owns, leases, operates, controls, or supervises a refinery.

Thus, if final blending occurs in a tanker truck being filled with various fuel components from a blending rack, EPA considers that to be an entity covered by the regulation, so that the finished fuel product delivered by the truck to a retail outlet has known and legally permitted characteristics. For purposes of this discussion, therefore, *refinery* refers to the point of finished fuel distribution at which net GHG impacts are reconciled for accounting purposes under the cap and *refiner* refers to parties obligated with allowance submission.

This point of regulation is further downstream than the "refinery gate" that some proposals suggest for transportation under cap-and-trade. While the refinery gate can suffice for tracking the fossil carbon passing through the conventional refining system, is does not suffice for properly tracking the emissions from transportation fuel delivered to end-users because some product streams -- particularly those for many biofuels -- do not pass through a refinery gate.

When biogenic carbon is left out of the cap, fewer allowances need to be submitted when biofuels substitute for fossil fuels. Refiners get the benefit of the doubt in that they have no responsibility to procure biofuels supplied through a chain having net uncapped GHG emissions that are verifiably lower than the direct CO_2 emissions from fossil fuels they displace, but the climate bears the risk of unaccounted emissions. Otherwise put, this use of the renewability shortcut creates a problem of incomplete information -- indeed, what can be termed an adverse selection risk[41] -- that inhibits the development of a transparent market for fuel sector GHG reduction tied to the cap.

One key part of the solution to this problem is requiring allowance submission for the biogenic carbon or, in the approach is taken here, for the fossil fuel energy equivalent carbon in the biofuel. Specifically, refiners would be obligated to:

- report the total energy value of all fuel they distribute, whether of fossil or biomass origin;
- hold allowances sufficient to cover the equivalent conventional direct (molecular) fuel carbon content corresponding to the energy value of all fuel they distribute regardless of origin;
- obtain credit (reduction in allowance requirements) only to the extent of fuel's rating to a level of net uncapped GHG emissions lower than the displaced direct carbon in conventional fuel.

Thus, this approach treats ethanol as if it had the same end-use CO_2 emissions as ordinary gasoline. Similarly, biodiesel is treated as having the same CO_2 emissions as conventional diesel. Such ratings would also apply to biomass feedstocks, whether they are inputs for an identified biofuel or inputs that displace crude oil at higher points in the supply chain (as in the production of renewable diesel). Any of these biofuels or feedstocks can, however, carry carbon credits (based on the FFAS described below) that can serve to reduce the resulting GHG allowance requirements.

Table 2 lists the direct CO_2 emissions, based on molecular carbon content, for common liquid fuels. These values are strictly physical properties and are not based on lifecycle analysis. The value of 71.8 gCO_2/MJ shown here for gasoline is numerically less than the full-fuel cycle emissions ("carbon

Table 2. Direct CO_2 emissions from end-use consumption of some common transportation fuels

Fuel	Energy Content (volumetric LHV) MJ/gal	Direct CO_2 Emissions gCO_2/MJ
Gasoline, conventional	121.9	71.81
Gasoline, Federal reformulated	118.4	71.77
Gasoline, California reformulated	119.2	71.78
Ethanol (neat)	80.2	71.52
Diesel, conventional	135.6	76.24
Diesel, reformulated	135.0	76.54
Diesel, Fisher-Tropsch	125.3	73.34
Biodiesel (methyl ester)	123.5	77.47

Source: Derived from fuel properties tables in GREET 1.6; values are given on a Lower Heating Value (LHV) basis; MJ = 10^6 Joules = 0.9479 kBtu.

intensity," or CI) factors proposed for a LCA-based fuels performance standard. For example, the 95.9 gCO_2/MJ CI value for reformulated gasoline blendstock used by CARB is 34% higher than the molecular carbon content, since it reflects all upstream emissions.[42]

Note how, on a delivered energy (Btu or MJ) basis, direct CO_2 emissions vary little for similar-use fuels. Putting biofuels in the cap would require allowance submission for the molecular carbon content of all finished fuel products regardless of origin (bio- or fossil). In this case, the other elements of this paper's overall approach (FFAS for tracking credits and LPF for addressing ILUC) would still work, with the refiners' obligation then based on biofuel's own direct molecular carbon content as shown in Table 2. The fossil-equivalent protocol outlined here is an approximation in that it uses the direct carbon content and energy value of reference conventional fuels.

For example, one million gallons of Federal reformulated gasoline would have a delivered useful energy content (lower heating value) of 118 TJ and its consumption would directly release 8,498 metric tons of CO_2 (tCO_2); this result is a straightforward multiplication of the values in the table, noting that one metric ton is equal to one million grams. Thus, 8,498 allowances would need to be submitted by the refiner who supplies that batch of fuel.

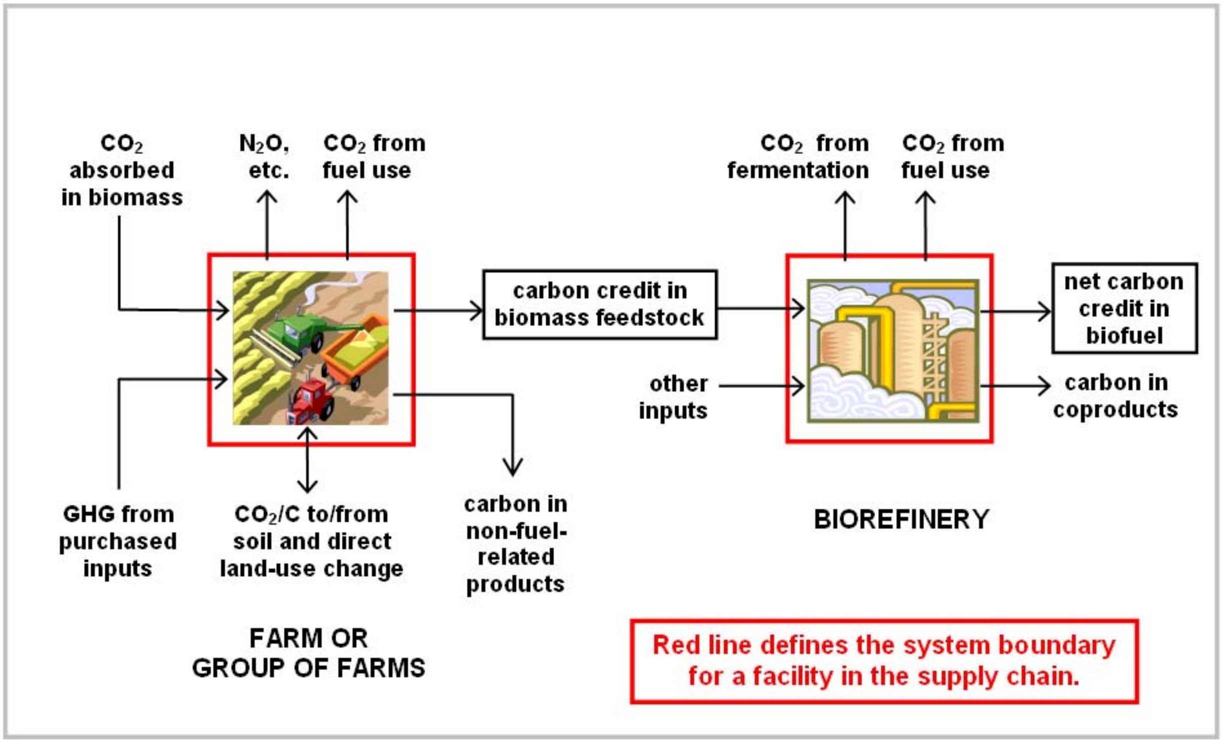
Similarly, if one million gallons of E85 (blend of 85% ethanol and 15% gasoline by volume) are distributed and none if the ethanol is rated under the FFAS, the math is as shown in Table 3. The resulting 6,167 metric tons of gasoline-equivalent CO_2 emissions represent the number of allowances required for distribution of that quantity of fuel.

Because in this example the ethanol is assumed to be unrated, the carbon content used is that of gasoline (71.8 gCO_2/MJ), which serves as the reference fuel. While not quite as accurate as using the direct carbon content of ethanol, this default assumption entails only straightforward reporting of

Table 3. Example allowance calculation for unrated E85

850,000	gallons of ethanol × 80.2 MJ/gal × 71.77 gCO_2/MJ =	4,892 tCO_2
150,000	gallons of gasoline × 118.4 MJ/gal × 71.77 gCO_2/MJ =	1,275 tCO_2
1,000,000	gallons of unrated E85 sums to:	6,167 tCO_2

Figure 4. Illustration of carbon balances for tracking emissions in a fuel supply chain



the energy value of all fuels and fuel blending components. The lower total of 6,167 tCO_2 for the million gallons of E85 compared to 8,478 tCO_2 for a million gallons of gasoline reflects the lower energy density of ethanol relative to gasoline.

A FFAS-rated fuel would have a different (presumably much lower) carbon impact (net gCO_2/MJ) than the default based on conventional fuel. The rating would contain the molecular carbon content of the fuel less any credits it carries based on verifiable carbon (GHG) balance data from its supply chain after debiting all uncapped emissions throughout the supply chain. Therefore, instead of using the renewability shortcut, a carbon update credit is carried forward through the FFAS ratings.

Emissions accounting in the supply chain

Conceptually, the FFAS approach involves examining the GHG fluxes across the system boundary of individual facilities in the supply chain, as illustrated in Figure 4. "Facility" here refers to any entity involved in the production of biomass feedstocks or fuels, including farms or forests as well as biorefineries. The basis for the accounting is simply a carbon balance (tallying all GHG fluxes) for each facility, distinguishing capped from uncapped emissions as in the examples given below.

For a fuel or feedstock to obtain a FFAS rating, every major entity in its supply chain would have to report uncapped emissions. A facility that is capped (e.g., as a stationary source) need not report the capped portion of its emissions for the purposes of rating its step in the supply chain. For example, emissions from generating the electricity purchased by a biorefinery need not be included as part of a fuel's rating value if it comes from a capped electric utility. However, other emissions at the biorefinery (e.g., CO_2 from fermentation tanks) must be included.

Feedstock supply

The most challenging aspect of a FFAS system is at the origin of the supply chain, namely feedstock production facilities such as farms and forests. However, empirical methods have been developed for assessing GHG balances in the field for purposes of validating agricultural offsets.[43] Similar techniques could be applied at the level of a cooperative, district or perhaps county to provide data that are sufficiently specific for feedstock FFAS ratings that can be carried forward as input data for computing fuel FFAS values.

Table 4 shows how such a tally might be done for feedstock production, in this case for a feedstock supply "facility" defined as the group of farms supplying corn to a particular ethanol plant. Based on a recent case study[44] of a state-of-the-art biorefinery using local rain-fed corn as feedstock, these data may reflect better-than-average practice. Thus, the example is strictly illustrative, for the purpose of explaining how the FFAS approach works rather than for providing representative values. Also, this simplified discussion does not attempt to include all farm inputs and emissions sources, although many major items are listed (entries are shown for GHG emissions from fertilizer and other chemical inputs, but not for CO_2 from application of lime, for example).

Table 4. Example GHG emissions balance for group of farms supplying corn

	10^3 tonnes CO_2-eq	
Item	**all**	**uncapped**
CO_2 absorbed	(737.0)	(737.0)
Conservation tillage	(12.7)	(12.7)
Fertilizer production	22.6	3.8
Diesel fuel	10.0	--
Propane	3.9	--
Electricity	4.0	--
N_2O emissions	97.6	97.6
Direct land-use	10.5	10.5
Totals	**(601.1)**	**(637.8)**
kg CO_2-eq per bushel	(29.4)	(31.2)

Source: derived from Mueller et al. (2008), using data for one year of operations supplying 20.45 million bushels of corn to the Illinois River Energy Center.

The tally starts with the CO_2 absorbed in the crop. This credit (given in thousands of metric tons [kilotonnes] of CO_2) is readily calculated from the mass of biomass grown and standard values for carbon content.[45] Conservation tillage practices that build soil carbon also enter as a credit (a negative emission value). Also excluded here is any adjustment for other impacts, including emissions leakages such as ILUC, that occur outside of the direct supply chain. Those impacts must be handled by other mechanisms such as the LPF described below.

Emissions from purchased inputs, either fuels consumed on-site or from a power plant for electricity, are included in the table under the "all" emissions column, which is listed for reference. If these fuels come from facilities covered by the economy-wide cap, they do not carry over into the "uncapped" column of the tally. That is the case for the diesel fuel, propane and electricity in the example given here.

GHG emissions from the production of chemical inputs are treated in a similar manner. Only those for nitrogen fertilizer production are shown in Table 4. This example assumes that most of the emissions from fossil fuel use (such as natural gas) associated with fertilizer production fall under the cap.[46] If fertilizer is supplied from a facility whose GHG emissions are not covered by the cap, the associated emissions would need to be added to the uncapped emissions tally.

Nitrous oxide (N_2O) emissions are challenging to estimate and highly uncertain. However, site-specific estimates can be made using a variety of techniques and can be based on data regarding the quantity and timing of fertilizer application.[47] The case study referenced here used a N_2O estimate amounting to 97.6 kilotonnes CO_2-equivalent.[48] Finally, any direct land-use change, such as fields converted from a diverse growth reserve to crop production, must also be included, as illustrated by the last item before the total in the table.

For this example, the FFAS rating for the feedstock (roughly 20 million bushels of corn) is a net uncapped emissions credit of 637.8 kilotonnes CO_2-equivalent, or 31.2 kgCO_2-equivalent per bushel. This value is less than the on-farm portion of GHG emissions that would be derived in a lifecycle analysis, which does not distinguish between capped and uncapped emissions. Also note that this rating is a physical value measuring the direct uncapped GHG emissions associated with providing the feedstock. No baseline is involved and so the rating does not represent an "emissions reduction" relative to some other feedstock (although some components, such as the soil carbon flux, may need to be measured against a baseline). The result is an absolute physical value (rather than relative reduction) that can be carried forward into a cap-based carbon accounting process. Therefore, an additionality question does not arise even though leakage remains a concern.

Renewability shortcut not used

A key point is that no automatic credit toward the carbon cap is given simply because a fuel's feedstock is "renewable." Credit for biogenic carbon is given only for a feedstock carrying a FFAS rating, with the CO_2 absorbed from the atmosphere by plant growth being treated as an uncapped negative emission. (Refer back to the "CO_2 absorbed in biomass" arrow in Figure 4.) This value can be readily calculated from the carbon mass fraction of harvested biomass, which is the basis for the 737.0 kilotonne CO_2 value shown as the first item in Table 4. However, as just noted, this explicit accounting for CO_2 absorption does not address leakage.

Thus, under a FFAS approach, in order to obtain credit for such renewable carbon in their products, sellers of feedstock (e.g., corn, soybeans, cellulosic materials) would have to report emissions from all of the other uncapped inputs and processes at the farm where the feedstock was produced, as illustrated in the above example.

Carrying ratings in commodity trading contracts

As a bioenergy market reaches any reasonable scale, bio-feedstocks as well as biofuels and bio-based fuel components will be fungible, tradable commodities. Their FFAS ratings would need to be integrated into commercial transaction records and could be included in commodity trading contracts. An approach that exploits mechanisms of futures contract markets is likely to be more practical than a certification program separate from the established commodity trade.[49] Such a contract would create an obligation to supply a commodity of a certain, known "quality" rating in this case, based on vendor-certified but third-party verifiable data supplied according to the FFAS. In addition to FFAS ratings, contracts could also carry a more conventional sustainability certification information based on criteria such as location of origin or other practices and characteristics of environmental and social concern.

Practically speaking, feedstock FFAS rating might most commonly be done at a district or regional level rather than the individual farm level. Under a voluntary approach, no farmers would be required to produce a rating unless they wanted to sell products that had value toward meeting the carbon cap. It may take time to establish the necessary procedures and education will be needed to enable the agricultural and forestry communities to take advantage of the added value of FFAS-rated products in the carbon-constrained transportation fuels market. This situation suggests a potentially valuable role for agricultural extension services in developing and implementing the system.

Carbon credit for FFAS rated feedstocks could be applied anywhere in the fuel supply system. For example, forest residues carrying a FFAS rating could be supplied to a refinery equipped with a gasifier that generates syngas to displace natural gas or crude oil inputs, with the resulting carbon credit applied to refinery products for which allowances are being submitted. Similarly, a dedicated biomass crop (say, switchgrass) could be FFAS rated and used as input to an advanced biofuels process that yields alcohols or fungible blending components for "green gasoline" at a refinery, where the feedstock's FFAS credit could be applied. Further analysis is needed to specify a protocol for such feedstock crediting, which could be based on the number of allowances otherwise required to cover the molecular carbon in the fossil feedstock being displaced.

Table 5. Example GHG emissions balance for a corn ethanol biorefinery

	10^3 tonnes CO_2-eq	
Item	**all**	**uncapped**
Corn Feedstock	(637.8)	(637.8)
Electricity	24.9	--
Natural gas	90.2	--
CO_2 from fermentation	240.5	240.5
Totals	**(282.2)**	**(397.3)**
gCO_2e/MJ (LHV)	(63.0)	(88.8)

Source: derived from Mueller et al. (2008), using data for one year of operations at the Illinois River Energy Center, which produced 55.8 million gallons of anhydrous ethanol.

Carbon balance at biofuel production facility

For biorefineries or other processing facilities, carbon balance accounting is straightforward. It is based simply on characterizing GHG emissions across the boundaries of the facility and requires no information about the particular processes used in the facility. Process efficiencies will be reflected in less use of purchased fuels and avoided GHG emissions.

Recall again that the purpose of the FFAS approach is not comparison of fuels for meeting a mandate or performance standard, but rather accurate GHG accounting for fuel-related transactions in a carbon market. The reward comes in the form of an avoided cost of allowance submission at the price of carbon in the capped fuels, which translates to greater value for biofuels and feedstocks having lower net uncapped emissions during their production.

Table 5 illustrates such a calculation, using data for a biorefinery that processes the feedstock whose carbon credit was tallied in Table 4. The first line is the input feedstock credit to which the delivered corn is rated (in this case, a credit of 637.8 kilotonnes CO_2-equivalent). The "all" column again lists all emissions for comparison. Only uncapped emissions need be carried over to determine the credit to which the resulting fuel is rated under the FFAS approach.

Note the explicit tallying of CO_2 emissions released from fermentation. Although their calculations are internally consistent, LCA approaches traditionally omit or obscure these emissions because they are biogenic, as illustrated earlier by the gap in the system boundary in Figure 2(b). Because the feedstock is carrying a credit for the absorbed carbon, the portion of that carbon that gets re-released to the atmosphere during fermentation needs to be debited, as shown in the calculation given here.[50] Some biorefiners have been exploring whether such by-product CO_2 can be sold and sequestered, e.g., for enhanced oil recovery, in which case the magnitude of these emissions could decrease (or become zero if all the CO_2 were sequestered) in the facility balance sheet, resulting in a credit larger than the net 397.3 kilotonnes CO_2-equivalent shown in this example. The net credit in this case amounts to 88.8 gCO_2e/MJ based on the lower heating value (LHV) of ethanol.

Co-product allocation

Another important matter is the need for well-defined protocols to allocate the GHG credits across co-products. Within the commodity-based agricultural production system, biofuels and their feedstocks are but one part of a fluid slate of products that any given producer will offer based on the market conditions at any given time. The fate of carbon uptake that is the basis of a FFAS credit will vary depending on those conditions. Some of it enters the carbon-capped transportation sector, potentially displacing allowance requirements; other portions enter the uncapped agricultural sector that supplies food, feed, fiber and forest products.

The co-product allocation question has been a longstanding issue in traditional LCA methods, which commonly use economic factors to allocate estimated GHG emissions impacts across feedstocks, fuels and associated co-products. Moreover, when LCA methods are used, the co-product question necessarily applies not only to direct GHG impacts within the supply chain but also to indirect impacts such as ILUC.[51] Because both direct and indirect impacts are market driven, substitution elasticities, trade variables and other economic considerations enter into LCA allocation calculations, introducing additional layers of complexity and uncertainty (and disputability) into the results.

Under the annual basis carbon accounting using actual field- and facility-level data on which the FFAS approach is premised, co-product allocation can in principle be handled strictly on carbon-mass basis. Such an approach enables unambiguous tracking of biogenic carbon according to whether it ends up in a biofuel product that displaces fossil carbon in a capped sector or ends up as a non-fuel feedstock or other product in an uncapped sector. Market effects may shift the bio-based product mix annually. But these effects will be captured in the reported facility-level data, avoiding the need for economic modeling because changes in a producer's product slate will be directly reflected in the quantities of carbon-bearing products leaving the producer's facility. The value of co-products affects the economics of the operation and because the fuel-destined portion of facility output would be exposed to a carbon price signal through the FFAS, that value will be reflected in relative prices of fuel and non-fuel products. All that is needed to correctly track the carbon uptake credit is the mass of biogenic carbon contained in the fuel products. Such an approach would be unambiguous, involving straightforward calculations using measured facility data.

Allowance crediting for FFAS rated fuel

The rating derived above for ethanol using the FFAS can be applied in a net biofuel GHG *uncapped* emissions calculation and then substituted for the unrated values otherwise used to determine allowance requirements, as shown earlier in Table 3.

Ethanol having an FFAS-based uncapped emissions credit of 88.8 gCO_2e/MJ per Table 5 results in a net uncapped GHG emissions of 17.25 gCO_2e/MJ after adding the direct CO_2 emissions from combustion (71.52 gCO_2/MJ as shown in Table 2). The calculation for 1 million gallons of E85 blended using ethanol carrying such a FFAS credit is shown in Table 6. Instead of the 6,167 allowances that need to be submitted for 1 million gallons of unrated E85, only 100 allowances would be required for a similar batch of fuel blended using ethanol having the FFAS rating derived for the example given here.

Table 6. Example allowance calculation for FFAS rated E85

850,000	gallons of ethanol × 80.2 MJ/gal × (17.25) gCO_2/MJ =	(1,175) tCO_2
150,000	gallons of gasoline × 118.4 MJ/gal × 71.77 gCO_2/MJ =	1,275 tCO_2
1,000,000	gallons of the FFAS rated E85 sums to:	100 tCO_2

Note that the values developed here to illustrate the FFAS approach for crediting against allowance submission requirements under a cap are very different than those from a conventional lifecycle analysis. For example, the case study referenced for these illustrative calculations reports a GREET-derived lifecycle global warming impact of 55.5 gCO_2e/MJ for ethanol from the facility and farms examined.[52] This LCA-based value includes both capped and uncapped emissions and also uses the "renewability shortcut," and so the calculation methodology is completely different than the FFAS approach. Therefore, such a LCA-based value cannot be simply compared to the 17.25 gCO_2e/MJ credit derived here even though the underlying data are the same.

The net 100 tCO_2 allowance submission value may strike some as very low compared to the value of 6,167 tCO_2 for an equal volume of unrated E85, but several points should be kept in mind. One is that it covers only uncapped emissions; most of the fossil energy inputs to ethanol production are covered elsewhere under an economy-wide cap. The allowances needed to cover the associated emissions are required elsewhere and therefore reflected in the cost of fossil fuels and electricity faced by farmers and biorefiners. Another key point is that this value accounts only for direct supply-chain impacts; economically induced effects such as indirect land-use change are left to be handled through another mechanism. Finally, the value is very sensitive to the actual GHG efficiency of the supply chain. For example, if as suggested by some recent literature, the N_2O emissions from corn fields are triple the default assumptions used in the referenced case study, that change alone would raise the allowance submission requirements to 3,073 tCO_2 equivalent. That value is but half that of the 6,167 tCO_2 needed for unrated E85 shown as in Table 3, but much more than the 100 tCO_2 required if N_2O emissions are as low as commonly assumed.

A corollary to this discussion is that LCA results are inappropriate for determining or adjusting allowance requirements under a carbon cap. For example, it would be incorrect to determine credits by differencing full-fuel-cycle global warming impact estimates for gasoline and ethanol. The reasons include both the inconsistent system boundaries underlying the bio- vs. fossil-fuel lifecycle calculations (recall Figure 2); the failure to distinguish capped from uncapped emissions; and the fact that LCA fails to account for the different sectors (and perhaps different international jurisdictions) in which either the capped or uncapped emissions may occur. These basic inconsistencies rule out use of a LCA metric for addressing the emissions missed by carbon cap accounting even before considering the complications associated with economically induced effects.

Land Protection Fund

As for any expansion of global agricultural and forest products, increasing biofuel production compounds the pressure for land conversion, either directly or indirectly, to supply feedstocks.[53] Recent analyses have estimated large increases in deforestation due to the impact of biofuels demand on international commodity markets.[54] Other analyses have disputed such findings, emphasizing the complexities and uncertainties surrounding induced land-use change.[55]

ILUC can cause substantial leakage because the incremental increase in global demand for land increases the pressure to convert tropical forests, which have enormous stores of carbon.[56] Leakage occurs if market dynamics shift GHG emissions to another place in a way that negates some or all of the emissions reductions otherwise attributed to a climate protection project, policy or program.[57] It can be caused by a variety of phenomenon, particularly market-driven substitutions of production or factors of production (such as land), that result in GHG reductions in one region to be counterbalanced by emissions increases in another region. Another way to look at the situation is that the large release of CO_2 from forest conversion results in a "carbon debt" that negates the CO_2 absorption benefit of growing biofuel feedstocks for many years.[58]

It is commonly recognized that that agriculture is a net direct emitter of greenhouse gases and that growth in demand for agricultural and forestry products in general is among the forces driving tropical deforestation. This situation applies not only to corn grown for ethanol, but to seed oils and sugar cane as well as proposed dedicated biofuel crops such as switchgrass and any other purpose-grown energy feedstocks. Crops that are highly efficient at both biomass production and building soil carbon may enable additional GHG reductions in spite of their incremental demand for land, and productivity gains may lessen the impacts over time. Such technical improvements do not eliminate the trade off even though they may reduce its magnitude. Only agricultural and forestry waste streams that would decompose without any other use (including otherwise building soil carbon) *might* be immune from having an induced effect based on demand for arable land.[*] Assessing the magnitude of land-use effects is itself an area of emerging science.

Estimates of land-use change impacts

Although ILUC impacts related to biofuels are significant, not only their magnitude but also how to estimate them are unsettled. Traditional fuel cycle models based on process energy representations omit such effects and have no mechanisms for handling them. Development of enhanced LCA techniques, combining traditional process analysis with input-output LCA in order to better evaluate economic interactions, is in progress.[59] Such work may still yield an incomplete picture if ILUC impacts if it relies on a partial equilibrium framework. The primary approach used to date for estimating ILUC impacts is use of models that represent global commodity trades, such as those of the Global Trade Analysis Project (GTAP) or Food and Agricultural Policy Research Institute (FAPRI). CARB has used the GTAP model for its regulatory analysis.[60] EPA is using a combination of models and has ongoing work underway to integrate the various techniques and develop better assessments of induced effects.

One recent study estimated ILUC impacts equivalent to roughly an additional 100 gCO_2e/MJ for U.S. corn ethanol.[61] By comparison, typical lifecycle GHG emissions values based only on direct impacts are 74 gCO_2e/MJ for corn ethanol and 92 gCO_2e/MJ for conventional gasoline.[62] A range of 100–200 gCO_2e/MJ for ILUC impacts alone was identified by one group of analysts,[63] while the applicability and validity of such estimates has been disputed by others.[64] CARB's LCFS regulation uses a significantly lower ILUC estimate of 30 gCO_2e/MJ for corn ethanol.[65]

As part of its RFS rule development, EPA examined the ILUC issue in great depth and carried out an extensive review analysis using multiple models along with a peer-review process, as reported in its RFS2 NPRM and support documents.[66] EPA determined lifecycle GHG impacts by developing

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[*]As noted earlier, when products now considered "waste" come to have value in a carbon market, an incentive will arise to "produce" more of them. Policy design must be robust in the face of such market evolution regarding what is considered a valuable product; indeed, motivating such evolution to favor GHG reductions is a desirable outcome of market-based climate policy. Therefore, it may not be possible to "shortcut" carbon management by using policy specifications that pre-define any type of product or activity as "clean" in terms of GHG emissions; the importance of such caution is one of the main implications of this discussion paper.

scenarios over a range of time horizons with or without discounting. The NPRM listed illustrative results for a 100-year horizon with 2% discounting and a 30-year horizon with 0% discounting. For example, EPA's 30-yr, 0% value for gasoline amounts to 2,797 gCO_2e/MJ, which is close to 30 times the 92 gCO_2e/MJ commonly cited for gasoline because it represents a cumulative impact over 30 years. Scaling EPA's 30-yr, 0% ILUC value for corn ethanol by 30 years yields 60 gCO_2e/MJ,[67] roughly in the middle of a 30–100 gCO_2e/MJ range bounded at the low end by CARB's estimate.

Numerous assumptions are behind the wide range of views on ILUC. Some assumptions pertain to how to handle time-varying GHG fluxes from land-use change, and therefore represent judgments as opposed to values that are verifiable empirically (through data gathering and rigorous scientific method). Some assumptions (e.g., regarding productivities and elasticities) are in principle verifiable, so that uncertainties could decrease as more data become available. However, measurement certainty to the degree generally expected of metrics directly applied for environmental regulation seems unlikely given the complexity of the interactions involved and the need to rely on highly aggregate data and unverified hypotheses regarding the behavior of interlinked markets.[68]

Rough estimates of the magnitude of ILUC emissions impacts can be obtained by applying values given in terms of carbon intensity to biofuel volumes projected by EIA. The results are shown in Table 7. By 2020, for example, projected U.S. bio-based liquids consumption is 22 billion gallons, of which 88% is some form of ethanol. The resulting implied ILUC impacts are 57–190 $TgCO_2e$/yr based on a carbon intensity range of 30–100 gCO_2e/MJ. In calculating these purely illustrative ranges, no attempt was made to apply different values for biofuels that might be sourced from different feedstocks. For example, if breakthroughs enable a large fraction of ethanol to be made from waste materials, then impacts would be much lower assuming that the ILUC impact of waste-based feedstocks is zero. Similarly, if a greater portion of the biofuel supply turns out to be bio-gasoline or a bio-derived diesel fuel derived from wastes, or, say, algae grown on non-arable land, the impacts could also be much lower than the values in Table 7.

Mitigating induced impacts

Fundamentally, ILUC is an impact caused by demand growth encountering the finite resource of productive land globally available for crops, forests or other uses of biomass. It is a "macro" effect induced by the price signal from increased demand for agricultural and forestry products, whether caused by biofuels or other uses. If the biofuel-related portion of this price signal could be neutralized, or an equal-and-opposite price signal created and targeted for protecting vulnerable lands, then that would be a way to mitigate ILUC concerns.

A growing body of scientific and international policy work to address tropical deforestation emphasizes the importance of providing affirmative financial incentives to protect forests.[69] The basic principle is to compensate tropical forest nations (such as Brazil or Indonesia) for GHG reductions actually achieved based on measured reductions of deforestation, using remote sensing and other techniques to verify and monitor forest protection.[70] The resulting demonstrated reductions below a pre-determined baseline would use internationally approved criteria to relate forest preservation to carbon stocks and result in carbon credit certificates (offsets) made available to the carbon market. These strategies, termed "Reduction of Deforestation and Degradation" (REDD), are gaining acceptance by the international climate policy community.[71]

Such mechanisms could directly mitigate the added pressure on global land due to biofuels. However, the use of REDD mechanisms to address ILUC should not come at the expense of pre-existing needs for slowing and stopping tropical deforestation. In other words, to the extent that

Table 7. Projected U.S. biofuel consumption and possible ranges of ILUC impacts and hypothetical carbon mitigation costs

		2005	2010	2015	2020	2025	2030
Total bio-based liquids,[a] 10^9 gal/yr		4.1	13.9	18.2	22.3	31.4	36.6
Ethanol fraction[a]		98%	93%	90%	88%	83%	81%
Average energy value,[b] MJ/gal (LHV)		81.2	83.4	84.5	85.6	88.0	88.7
Biofuel energy consumption,[c] EJ/yr		0.33	1.16	1.53	1.90	2.76	3.25
ILUC impacts,[d] Tg CO_2e/yr	Low	10	35	46	57	83	97
	High	33	116	153	190	276	325
Allowance price,[e] 2005$/ton$CO_2$		10	10	13	16	21	27
Mitigation cost, 10^6 2005$	Low	100	350	600	910	1,740	2,630
(rounded)	High	330	1,160	2,000	3,050	5,810	8,760
Average cost per gallon, $	Low	0.02	0.03	0.03	0.04	0.06	0.07
(of bio-based liquids)	High	0.08	0.08	0.11	0.14	0.18	0.24

(a) Derived from Table 11 of EIA (2008a, for 2005) and EIA (2008b, for projection years).
(b) Assumes non-ethanol portion has characteristics of biodiesel or Fischer-Tropsch liquids (which are similar).
(c) In exajoules (10^{18}J), lower heating value (LHV) basis, derived per (a) and (b).
(d) Based on 30 gCO_2e/MJ for the Low value and 100 gCO_2e/MJ for the High value.
(e) Assumes $10/t for 2005-10; 2015-30 estimates are from EPA (2009c) analysis of ACESA (H.R. 2454).

biofuel production compounds the deforestation problem, the total resources available for REDD would need to be expanded beyond those otherwise considered necessary. In addition to incentives for protecting tropical forests, mechanisms for protecting or restoring other lands that can hold carbon stocks might also be expanded for addressing ILUC. Any such offsets should meet high standards for quality and eligibility, following the customary requirements that the GHG reductions must be real, permanent, additional, verifiable, enforceable, account for any added leakage that might be induced, and have robust measuring and monitoring protocols in place.[72]

Administration of a LPF would utilize data gathered for FFAS ratings supplemented by survey work to characterize the impacts of unrated feedstocks and fuels. The administering agency would quantify the ILUC impacts linked to total U.S. demand for biofuels and any other fuels that might induce land-use change. Such estimation can be done by applying the same global commodity and agricultural market models now being used to incorporate ILUC impacts into biofuels LCA. The values in Table 7 are illustrative of what the results of such estimations might be. Arguably, using such estimates to determine the number of offsets needed to mitigate the problem may be a more appropriate use of such highly aggregate, largely assumption-driven models than using them to define a product-specific metric for a LCA-based fuel regulation.

Possible mitigation costs

Given ILUC impact estimates, an administering agency would use the LPF to purchase the number of international forest offsets (REDD credits) needed to mitigate the leakage. The "mitigation cost" lines in Table 7 illustrate the ranges that might be involved using projected GHG allowance prices from EPA (2009c) modeling of ACESA (2009). Such estimates depend on the many assumptions that influence modeling the impacts of climate policies, the RFS and ILUC. Allowance prices, which range \$13–\$27 per ton of CO_2 over 2015–2030 for the EPA base ACESA scenario referenced here, determine the mitigation costs. (The prices in this example are notably lower than, say, the EPA (2008b) estimates for the Lieberman-Warner bill in the 110th Congress, mainly because of changed economic conditions and higher underlying energy prices.)

Based on the assumptions behind the modeling cited, the mitigation cost for the 22 billion gallons of U.S. biofuel consumption projected in 2020 roughly amounts to \$1–\$3 billion dollars. A LPF at this level would purchase international forest carbon offsets equivalent to the 57–190 $TgCO_2e$/yr needed to mitigate the estimated ILUC impact. More than ample international forest offsets are expected to be available at the allowance prices assumed here.[73] The bottom lines of Table 7 show the implied costs per gallon of biomass-based liquid fuel demand, implying 4¢–14¢ per gallon in 2020, for example. As for the questions of how a LPF would be funded and who pays for the mitigation, a number of options are possible as described in the discussion section, below.

DISCUSSION

The approach sketched here for addressing biofuels in the context of a fossil-based GHG emissions cap raises a variety of questions. While resolving all of them is beyond the scope of this paper, it is worth offering at least a preliminary discussion while acknowledging that readers are likely to have other perspectives as well as other issues to raise. See also Appendix B for additional responses to some of the concerns raised during peer review.

Key Issues

This first subsection of discussion addresses key issues and other questions that come to mind regarding the approach. The question of how it differs from fuels regulation based on lifecycle analysis is addressed in the second subsection, starting on p. 31.

Revisiting the "renewability shortcut"

As noted in the Introduction, a common policy analysis convention is to not count the biogenic carbon in biofuels and other forms of bioenergy. This "renewability shortcut" is used in official GHG emissions inventories, economic models of climate policy and most LCA models used as a basis for regulation of fuel lifecycle emissions. While longstanding and seemingly logical, this accounting shortcut rests on an assumption that added demand on agriculture and forestry for bioenergy production has no net impact on the carbon balance of the biosphere, including carbon stocks in lands and forests. However, this assumption should not be taken for granted; rather, climate policy should be designed to ensure that it limits emissions to targeted levels as verified by measured outcomes, rather than presumptions of what might happen *ceteris paribus,* or "other things equal," in terms of global land-based biological production.

A problem with the renewability shortcut is the presumption that bioenergy bears no burden of proof regarding the full additionality of the CO_2 reduction implied by the substitution of "young" for "old" carbon. Although assessments vary, the range of estimated land-use impacts is such that it can significantly reduce or negate benefits previously assumed for biofuels, whether derived from traditional crops or from energy crops that also compete for arable land. This concern is consistent with other scientific studies, not based on fuels LCA, indicating that one of the best possible uses of land from a global climate perspective is preserving and restoring forests.

This carbon accounting question is commonly recognized on the context of project-specific GHG management for the agriculture and forestry sectors. For example, according to the California Climate Action Registry's forest carbon protocol:

> … biological emissions are those resulting from … forest carbon pools [as identified in document] … and are considered emissions if an entity's total carbon stocks decline from one year to the next.[74]

It is conceptually straightforward to treat biogenic emissions correctly -- that is, as a measured net change in land-based biological carbon stocks -- in the context of a circumscribed entity, such as a farm or managed forest that might provide offsets. Techniques have been developed for measuring such changes in carbon stocks and accounting for leakage. The problem arises for fuel substitution that occurs outside of well-defined GHG management system, which is how biofuels have been treated in GHG emissions accounting protocols and public policy to date.[75]

Some of the literature on the land-use change issue characterizes it in term of carbon "payback" periods.[76] In LCA-based approaches, the time sequence of carbon releases (large release upon land clearing, slower releases from disturbed soils and a possible net loss of sequestration capacity) gets reflected in modeling assumptions that estimate time distributions of emissions and apply discount factors to represent the climate forcing effect of the CO_2 releases over time.[77] These considerations add another layer of complexity and disputability to a lifecycle-based metric.

In contrast to LCA approaches that attempt to incorporate major spatio-temporal effects through modeling, cap-based accounting is strictly static based on annual (or other relatively short period) compliance accounting. If allowances or offsets are required to cover any estimated emissions release from land-use change at the time when it occurs, then mechanisms of capital markets can be used to address temporal effects, with the associated risks being priced into the trading. Such an approach has been described for carbon sinks.[78] Similar mechanisms might also be used to address carbon sources due to land-use change.

Regardless of the approach taken for fuels policy, GHG inventories should consider fully reporting the bioenergy CO_2 emissions now omitted from their totals. Such reporting is optional under current IPCC guidelines. The U.S. EPA inventory, for example, tabulates biogenic emissions even though they are not included in the total estimate for national GHG emissions. In 2005, CO_2 emissions from "wood biomass and ethanol consumption" in the United States amounted to 207 Tg, compared to 5,751 Tg of CO_2 from fossil fuel combustion.[79] The "negative" emissions of growing biomass could then be given as a separate line item, perhaps included with the statistics now covering the CO_2 sinks in land-use and forestry. Interpretation of such statistics would still need to consider how the overall carbon balance of the biosphere changes as result of the bioenergy production. Fully requiring such reporting would be non-trivial and entail modifying international GHG emissions reporting guidelines.

In energy and emissions models, such an accounting adjustment would change the picture from what is now illustrated here in Figures 1 and 3 based on DOE's *Annual Energy Outlook*. As noted earlier, the apparent CO_2 reductions suggested by traditional accounting is incorrect even under optimistic assumptions about the net reductions from biofuels. It would be more transparent to show direct transportation sector "emissions certain" in their entirety while crediting any net CO_2 reductions in the sector, such as agriculture, where it occurs based on verifiable, leakage-adjusted absorption of CO_2 through plant growth.

Interaction of this approach with the RFS

The approach outlined here can co-exist the RFS; it does not interfere with the basic fuel volume requirements although it does eliminate the need for the lifecycle GHG requirements for various categories of biofuels. Because the use of FFAS would be voluntary, no special provisions would be needed to "grandfather" fuels from producers who do not rate their products. For example, some of the ethanol from existing facilities that the RFS exempts from GHG reduction thresholds would likely remain unrated until the value of a FFAS rating makes it worthwhile for the producer.

Nevertheless, while the RFS would still exist, a carbon cap backed by a FFAS system would avoid creating an incentive to produce unrated renewable fuels beyond RFS volumes because such fuels would have no competitive advantage in the carbon market. Because it requires verifiable measurement of net GHG emissions from the production of feedstocks and fuels, the FFAS in conjunction with the inclusion of fuels under the cap would create a market incentive for emissions reduction and innovation throughout the fuel supply chain.

No GHG reduction credit would be given for products lacking a verifiable supply-chain FFAS rating. The incentive to use the FFAS is provided by the value that rated products have for reducing refiners' allowance requirements, a value that will propagate through the supply chain. A biorefiner could not rate its fuel unless it all of its feedstocks were rated. Under a voluntary approach, biofuels from existing facilities grandfathered under the RFS may have little incentive to rate their fuels and require rated feedstocks. However, given the market uncertainties faced by biofuel producers (as seen with the drop in gasoline prices and a dampening of fuel demand overall), the added value that can be attached to FFAS rated products is likely to be attractive.

Thus, any growth beyond RFS volumes is market-driven based on a product's ability to show value (in the form of a FFAS rated GHG impact less than that of conventional fuel) for reducing the number of allowances needed under the carbon cap. Producers would have to weigh the value of producing FFAS-rated feedstocks and fuels against added costs of fossil inputs due to the cap-and-trade system, but it could provide another way for producers in the agricultural sector to derived benefits from climate policy, analogous to their benefits from offset programs.[80]

Financing a Land Protection Fund

If a LPF is used to mitigate ILUC instead of treating ILUC impacts as an addition to uncapped emissions tally under the FFAS, it still leaves a question of who should pay for the mitigation. Several options come to mind, all of which have challenges. A sense of magnitude for the costs involved can be seen by referring back to Table 7.

One option would be to allocate a portion of carbon market allowance revenues to a LPF. An issue here is that many demands exist for the use of allowance revenues. In particular, it would be counterproductive if a portion devoted to LPF mitigation detracted from the portion of allowance revenues that would have been made available for REDD on the basis of pre-existing needs apart from the added pressure on land conversion from biofuels.

Alternatively but also within a carbon market context, funds could be raised from a surcharge on allowances purchased to cover the carbon in petroleum-based fuels. A rationale is that, because of oil's unique energy security risks compared to other fossil fuels, oil-based CO_2 emissions reductions should be more costly to trade away than, say, coal-based reductions.[81] Although not targeted to biofuels-related impacts economically speaking, this approach can be seen as a way to amplify rather than undermine the incentive for non-petroleum fuels that is an established energy policy goal. A surcharge could be based on estimates of the energy security externality associated with U.S. petroleum demand. A recent such estimate is $14 per barrel of oil,[82] or about 29¢ per gallon of gasoline, which corresponds to $33/ton$CO_2$ on the basis of petroleum carbon content. New analysis would be needed to estimate the volume of likely allowance trades on which such a fee would be assessed and how the resulting revenue would compare to the amount needed for a LPF.

Outside of a carbon market context, an LPF could be financed through an energy security tax on petroleum fuels. The cost could then be spread over a broad and fairly well-known base, such as all U.S. oil use or oil imports. For example, spreading $14/bbl over the 9.8 million barrels per day of gross petroleum imports projected by EIA (2008a) would yield about $50 billion, much more than the $1-3 billion ILUC mitigation cost estimated under given assumptions as shown in Table 7. Thus, even a partial energy security externality tax would amply cover the costs of an LPF.

Better targeted from an economic perspective would be an ILUC impact fee levied on biomass feedstocks and therefore passed on to biofuels produced from them. All of the questions about how to differentiate impacts according to the nature of feedstock and where and how it is grown would remain. Of course, this approach transfers the debate regarding use of an ILUC metric in lifecycle regulation to one regarding use of an ILUC metric to assess a fee on biomass feedstocks and their associated fuels. Whether or not the LPF is fee-based, policy makers will not sidestep the disputes that surround any proposal to apply a globally-derived metric to domestic feedstock and fuel producers who individually have no direct control over the ILUC emissions which would affect the value of their products. Obviously, all of the possible approaches on ILUC have pros and cons that will be viewed differently by different stakeholders in the debate.

Would this approach be technology forcing?

One of the rationales for a fuels performance standard such as a LCFS is the belief that the price signal from a carbon cap would be too weak, particularly in early years, to motivate the degree of long-term technology change ultimately needed in fuels. A question arises of whether the approach outlined here, lacking a LCFS even while providing rigorous carbon accounting coupled to the cap, is adequate for playing the "technology-forcing" role that some see as important.

Alternative fuel proponents argue that a carbon cap is similar to a tax and that neither policy is sufficiently technology-forcing. A recent article promoting the LCFS states:

> Some day, when advanced biofuels and electric and hydrogen vehicles are commercially viable options, cap and trade and carbon taxes will become an effective policy with the transport sector. But until then, more direct forcing mechanisms, such as a LCFS for refiners, are needed to stimulate innovation and overcome the many barriers to change.[83]

This reasoning seems to presume that a carbon cap would be effective only upon the commercial availability of certain technologies, rather than allowing that the carbon constraint might itself drive technology change. It also equates a cap and a tax. Although this paper cannot review the literature debating that issue, neither of these presumptions are universally shared. Indeed, the premise of a cap-based policy is that a binding constraint on emissions is essential for environmental integrity and that markets themselves -- as opposed to policies based on prospective assessments of what technologies might or might not work -- will drive innovations and find the most cost-effective ways to meet the environmental constraint.

A distinction needs to be made between the effect of a carbon cap and its associated price signal on *energy demand* and its effect on the *GHG emissions* of transportation fuel supply. The elasticity of GHG emissions is not identical to the elasticity of energy demand, although the latter is one component of the former. Empirically, transportation energy demand is fairly inelastic.[84] Given the structural complexities of markets for vehicles and non-fuel aspects of the transportation system (e.g., land-use planning and infrastructure), such evidence supports the need for complementary policies such as regulations to address vehicle efficiency and public planning to address travel demand. But good evidence does not exist for the market response regarding the net GHG emissions associated with the transportation fuel supply system. The case for a technology-forcing fuel regulation, however, assumes that its response is zero, i.e., that the only response to a carbon constraint and associated price signal is the energy demand response.

Thus, though it may be widely held in some policy circles, the need for "technology forcing" regulation in addition to a rigorously specified cap covering transportation fuels seems to be no more than a belief. It is not supported by market-based policy principles.[85] Neither is it supported by historical evidence; indeed, the experience with technology-based policies for transportation fuels is poor.[86] While volumes of ethanol and other alternative fuels are being mandated, it is far from clear that the RFS is leading to a sustainable, market-transforming business. Many attempts to advance other alternative fuels over the years have failed.[87] Brazil's experience with ethanol is often held up as a success, but whether it is transferable and how well it actually reduces net GHG emissions remain open questions.[88]

In short, because no sufficiently similar policy has ever been tried, there really is no evidence one way or another regarding the effectiveness of a carbon cap on the net GHG emissions associated with supplying transportation fuels. Therefore, it cannot be claimed that a carbon cap covering transportation fuels would be ineffective; neither is there clear evidence that it would be effective. Nevertheless, the downstream fuel business in particular is competitive and very cost-sensitive, often operating with thin margins. It is plausible that a well-crafted policy, rigorously coupling the fuels market to allowance submission requirements with an appropriate point of regulation at the point of finished fuel product distribution, will provide an effective motivation for GHG emissions reductions never before needed in the fuels market.

Examining the response of the transportation fuel supply system to being under an economy-wide carbon cap that constrains the market and thereby provides a value for GHG reduction in fuel production is a worthy topic for analysis. It is a question that has been neglected to date, perhaps because analysts mistakenly equate elasticity of fuel GHG emissions with elasticity of fuel demand, or because they assume that the dismal experience with technology-based alternative fuels policies implies that a market-based policy would also fail for the sector.

Traceability of uncapped production-phase emissions

The FFAS approach outlined here for tracking uncapped emissions during the production of bio-based feedstocks and fuels requires a mechanism for tracing verifiable data through commercial transactions involving these products. This issue is common to any regulatory or certification system that attempts to address impacts associated with the production of a good that do not leave a physical or chemical imprint on the good itself, and which therefore must be traced by information tied to a product's records as it traverses the chain of custody.

Ensuring the integrity of such information, particularly across international borders, can be a challenge. As experience with sustainable products certification has shown, careful oversight, interjurisdictional cooperation and integrity are crucial for avoiding risks of records falsification.[89] This paper can do no more than acknowledge these challenges while noting that they exist regardless of the policy approach taken. Such challenges could well be worse under a system whose reliability cannot be ascertained without requiring such information for all fuels, such as an LCFS.

Indeed, as proposed to date, lifecycle-based regulation sidesteps the issue by making extensive use of defaults and process pathway assumptions and the hope that "cleaner" producers will offer data in order to obtain a better LCA-based carbon intensity value. However, given the fact that such defaults may be based on negotiated modeling assumptions working from selective survey data, there are serious risks of adverse selection and it may be difficult to have confidence in the results. It is unclear that any fuel lifecycle models to date have been validated with independently verified, statistically representative data. Verifying the compliance of regulated entities through modeling rather than reporting of entity-specific data is an unusual approach to environmental management. Some might raise a concern that the reporting requirements for an approach such as that outlined here are too onerous to be practical. However, without verification, the benefits of a policy that is largely based on modeled rather than measured performance could prove to be illusory.

The FFAS approach outlined here does not attempt to immediately assess the emissions impact of all biofuels, and is intended to be based on measurement and reporting of emissions and directly related physical flows rather than modeling. It takes a precautionary approach by assuming that biofuels have no reductions relative to conventional fuel except as documented. Because the use of the FFAS is voluntary, the system can be initiated at a small scale with a few producers able to pioneer the procedures, permitting oversight of early implementation of the accounting standards by agencies and third-party auditors whose methods can be developed, tested, refined and validated for broader use. In this way, the FFAS ratings -- and therefore the emissions tracked for reliable accounting in the cap-and-trade system -- will not get "ahead of the science" by relying on modeling that is highly uncertain and disputable.

Methods for ensuring traceability of rating information can be developed and validated in parallel with the direct application of the FFAS for commercial feedstocks, fuels and fuel components. As noted earlier, the ratings could be incorporated into commodity trading instruments, adapting concepts that have been proposed for biofuels sustainability certification.[90] The quantitative metric of net uncapped GHG emissions (often negative, i.e., a credit) associated with a feedstock or fuel could be combined with other sustainability information for ensuring that the products meet desired environmental standards overall. Although system with well-defined protocols for rating products in an objective manner tied to a national environmental protection policy should in principle conform to World Trade Organization (WTO) rules against trade discrimination, carefully examining trade-related issues is a matter for future analysis.

How this approach differs from regulation based on lifecycle analysis

The approach outlined here shares with fuel lifecycle-based ("carbon intensity") regulation a common ideal of accounting for all GHG emissions associated with the production and use of transportation fuel. However, it differs from LCA-based regulation in significant ways:

- It does not account for everything in one place; rather than a single LCA-based regulatory metric separate from the cap, it uses a three-part approach integrated into the cap.
- It tracks only uncapped emissions, whereas LCA tracks all emissions regardless of whether they are capped or not.

- It tracks production-phase emissions directly measured at facilities (including farms and forests) rather than as emissions remotely associated with fuel product via assumed pathways.
- Because FFAS treats production processes as a "black box," there is no need for the extensive process modeling which forms the basis of LCA ("full fuel cycle" analysis) as applied to date.
- It entails a top-down, environmental-needs-based driver for technology change, rather than a bottom-up driver based on (and limited by) prospective technology assessment studies.
- The approach aims for GHG management rather than product promotion.
- It does not handle imports of high-carbon crudes or other unconventional fossil resources which would be captured in a LCA-based regulation.
- It provides a greater degree of market-based flexibility and would most likely result in lower costs to both producers and consumers than a LCFS.

Some of these differences pertain to methodology and assignment of responsibility. Also, as outlined here, this approach focuses on the particular challenges associated with biofuels and so does not attempt to cover all possible transportation fuels such as petroleum-based fuels from high-carbon fossil resources to electricity and hydrogen derived from a variety of sources. Nevertheless, concepts similar to those discussed here would be adaptable to biomass-based electricity and hydrogen, which now suffer from the same issues due to use of the renewability shortcut. Several of the distinctions between this approach and lifecycle-based regulation are elaborated as follows.

Three-part mechanism

One notable difference is that, rather than using a single mechanism (lifecycle regulation administered separately from the cap-and-trade system), this approach uses a three-part mechanism integrated into the cap. Instead of reducing the accounting to a single number, it effects complete accounting through the three components of: (1) rigorous specification of allowance submission requirements for transportation fuels in the cap; (2) accounting standards (FFAS) for uncapped GHG emissions in the direct fuel supply chain; and (3) a land protection fund LPF to address GHG emissions from indirect land-use change that occurs outside of the direct fuel supply chain.

Focus on facilities rather than products, measured data rather than modeled processes

The FFAS approach would entail procedures for measuring emissions at facilities that produce feedstocks and fuels rather than modeling processes associated with the production of different categories of feedstock or product. Thus, categories such as "cellulosic ethanol" or "corn ethanol" are not relevant to the methodology, which is oriented not to product discrimination, but rather to ensuring complete accounting at the point of allowance submission under the cap. Also unnecessary is the multiplicity of feedstock-fuel "pathways" that LCA modelers create in an attempt to achieve better discrimination in the face of ever-evolving options and practices.

Although LCA methods ideally could be based on actual data, this ideal is not how LCA-based regulations are being promulgated in practice. Both CARB and EPA rely heavily on a "check box" approach defined using lists of feedstock-fuel pathways. While the rules allow producers to substitute actual data, the defaults are all based on modeling, resulting in a system with significant risks of adverse selection. That is to say, a pathways-based regulatory approach sets up a situation of asymmetric information because parties can comply without providing verifiable, facility-specific data, running the risk that actual GHG emissions are higher than those modeled for the pathway under which an obligated party complies.

The liabilities of such an approach are implicitly acknowledged in EPA's recent RFS NPRM, which notes that, as for the original RFS based on EPACT (2005), the proposed regulation "does not distinguish biofuel on the basis of where within the country the biofuel feedstock was grown…," even while noting the significant regional differences that exit.[91] Among EPA's rationales is the fact that feedstocks are widely traded commodities; in contrast, the approach outlined here suggests tackling this issue head-on, for example, by attaching FFAS ratings to commodity trading contracts. The transportation fuels market is a commodity market and so, to be effective, climate policy must create affirmative incentives and verifiable mechanisms for tracing GHG emissions impacts through market transactions, rather than sidestep the issue through extensive use of defaulting.

Compared to LCA-based regulation such as an LCFS and parts of the RFS, the approach outlined here is more like traditional facilities regulation in that its focus is the set of entities along the supply chain. However, instead of regulating facilities for their emissions (beyond the extent to which they may already be regulated as covered entities in the cap-and-trade system), it requires verifiable reporting of uncapped emissions (GHG fluxes both positive and negative across a facility boundary) if a facility wishes its products to carry a FFAS rating that enables GHG allowance crediting. While not claiming to regulate all fuel-related GHG emissions, the voluntary FFAS approach attempts to balance the need for environmental integrity in sectors that policymakers decide to regulate against the need to respect policy decisions that leave certain sectors and sources unregulated. And as noted above, the traceability challenges of a FFAS system are likely to be less risky and more containable that those of a LCFS.

The benefits of a given practice or process at the facility where it is used will be reflected in the measurement-based accounting that is tied to actual, commercially traded products produced (feedstock, fuels or fuel components) and rated according to the FFAS protocol. Efficiently produced corn, for example, using rain-fed agriculture with minimal inputs involving uncapped emissions and precise fertilization to minimize N_2O emissions, will automatically reflect a large FFAS-based credit when its actual uncapped emissions are tallied, resulting in a larger credit available to a biorefiner that processes it and subsequently resulting in a need for fewer allowances to be submitted by refiners blending the resulting corn ethanol into their fuels.

Therefore, a key corollary to the approach outlined here is this:

> **A market-based policy that establishes sound GHG management throughout the supply chain need not entail explicit comparisons of fuels.**

In other words, the focus on facilities where emissions occur rather than their products, and the emphasis on actual production data rather than assumed processes, means that policy makers need not put themselves in the position of judging certain fuels as "clean" or "dirty" relative to others.[92] Moreover, this approach will quickly reflect changes that affect actual emissions, whether they are running incremental improvements in operations that reduce emissions or weather-related variables that might increase purchased inputs. The FFAS system thereby ensures accurate accounting while avoiding (or at least minimizing) the adverse selection risk of an approach based mainly on process characterization and heavy reliance on default assumptions.

With FFAS ratings incorporated into market transactions for the bio-based feedstocks and fuels, their value for GHG mitigation will be reflected in their price. This will enable the carbon market to drive reductions, rather than needing a potentially cumbersome (and possibly contentious) regulatory deliberations that involve explicit comparison of products. This paradigm is consistent with the fact that it is the "stationary source" emissions associated with production that should be the object of attention, rather than the products themselves, which are otherwise fungible (i.e., corn ethanol is the same chemical as cellulosic ethanol) regardless of how they were produced.

Toward GHG management for fuels

The facilities and measurement focus of the approach sketch here can also be viewed as striving for emissions *management* rather than emissions *reduction*. Reductions will then follow from the carbon constraint and resulting price signals on the managed system. The distinction between management and reduction is not just semantic, but has implications for policy design. Nevertheless, both are means to the end, which is neither management nor reduction *per se*, but rather the verifiable *limitation* of economy-wide emissions to climate protective levels defined by the cap.

Traditional energy policy approaches are reduction oriented. They are commonly designed on the basis of options (technologies and practices) considered to cut emissions below levels projected in the absence of new policy. For transportation fuels, this paradigm has inspired policies that promote (e.g., through mandates and incentives) options that are believed to reduce emissions. Such is the case for both the RFS and LCFS as envisioned to date. Of course, a LCFS could evolve toward a true management system by means of provisions that enable fuel suppliers to substitute actual production data for modeling that otherwise projects lifecycle GHG intensities for categories of feedstocks, processes and fuels ("pathways").

The approach outlined in this paper emphasizes the dictum, "what gets measured, gets managed." The policy mechanism (the FFAS) is defined around verifiable emissions data for individual producers of feedstocks and fuels. When direct measurement is not feasible, the system can use impact-specific models with local inputs, e.g., for estimating N_2O emissions and soil carbon fluxes, as opposed to overall systems modeling based on generic data for broad feedstock categories. For induced effects that occur outside a commercially traceable supply chain, a management-based approach would strive to handle them directly *in situ*, e.g., through REDD incentives for forest carbon management to mitigate indirect land-use change. Again, the focus is on the "producer," in this case of forest carbon stocks, which are likely to be best managed at the national level.

Another way to look at the distinction in approaches is that a management-based paradigm seeks to establish a transparent, well-functioning market by eliminating the information barrier due to lack of knowledge about emissions in the fuel supply chain. It relies on the economy-wide cap and resulting market signals (reflected in differential prices for FFAS rated products) to motivate emissions reducing options throughout the supply chain, be they feedstocks, products or practices, and do so without having the policy pre-identify them as such. By emphasizing transparency, a GHG management system will foster emissions reductions of any verifiable form. Some of these reductions are likely to be found what are considered "high- carbon fuels," whether of bio- or fossil-origin, because that may well be where the most cost-effective GHG mitigation opportunities lie.

Addressing high-carbon conventional fuels, other "imported" emissions

One concern that the FFAS approach does not address but which a LCFS claims to address is the upstream (production) emissions from high-carbon fossil fuels. These are conventional products such as gasoline and diesel derived at least in part from inputs that entail higher production-phase GHG emissions than conventional petroleum inputs such as light crude oil. Such high-carbon feedstocks include coal (for coal-to-liquids processes), heavy crudes, bitumen (such as tar sands) and other unconventional resources (such as shale oils).

If these resources are extracted and processed in the United States, then they would fall under the cap and their additional production emissions are covered. However, if they are imported, as either synthetic crude or refined product, then their additional upstream emissions are not covered. As shown in Table 1, imported high-carbon fuel sources that would be missed by a U.S. carbon cap involved upstream emissions amounting to an additional 3% over U.S. transportation sector direct CO_2 emissions as of 2005 and that impact is projected to grow to 11% by 2030.

The emissions associated with imported fossil-derived fuels are in principle no different than those for other imported products. It is fair to ask whether they should be treated differently than embodied GHG emissions of other products (such as steel, timber, durable goods) produced overseas in uncapped nations. They therefore might be handled best by mechanisms designed to address trade-related impacts, such as border adjustments or other policies having an ultimate goal of encouraging countries with which we trade to also adopt carbon caps. In any case, lack of coverage for such emissions is a limitation of the voluntary FFAS approach outlined here that merits additional analysis. It could conceivably be handled by a system requiring mandatory reporting of uncapped GHG emissions associated with all fuels, but such an approach could face a question of why it would not be required for all products, not just fuels. Recall that the rationale for a special approach such as FFAS for biofuels is the substitution of uncapped biogenic carbon for capped fossil carbon, a problem that does not arise in the case of embodied emissions generally.

Likely lower costs to consumers and producers than a LCFS

A cap-and-trade approach is considered to be a least-cost way to achieve a given level of emissions reductions. For transportation fuels the evidence to support such a claim is limited, although cap-based approaches with credit trading have been successfully used to administer both the elimination of lead and the reduction of sulfur in fuels.[93]

Analysis of California's proposed LCFS projects that it would be economically beneficial to the state.[94] Other economic analysis indicates that a LCFS is not a cost-effective way to reduce fuel GHG emissions.[95] In any case, views regarding LCFS cost-effectiveness depend on assumptions regarding the future costs of technology options that have not yet been proven commercially viable, such as the production of cellulosic ethanol. However, if such options do become available at costs as low as proponents project, those economic benefits would also be captured by a cap-and-trade policy. Thus, it is reasonable to expect that a policy anchored in cap-and-trade would be no more costly than a LCFS, and likely to be less costly if assumptions regarding the cost-effectiveness of technologies assumed for a LCFS are not born out.

CONCLUSION

Placing a cap -- a declining, legally binding limit -- on GHG emissions at the national level is an essential cornerstone of climate mitigation policy. Combined with emissions trading, the resulting program offers an economically efficient carbon management framework for reducing emissions across sectors and by a variety of means including technological innovation and behavioral change.

However, the determinants of GHG emissions are complex. A simple carbon market alone does not to suffice to address structural factors, long-lived investments in energy supply systems and infrastructure, the role of other national priorities and other policy considerations that shape or constrain the many factors that determine GHG emissions. Moreover, the distinctive characteristics of existing, intertwined energy and related product and service markets affect the response to a cap-and-trade system and the price signal it generates. For these reasons, comprehensive climate policy proposals include additional measures that complement and enhance the cap-and-trade system, ideally leading to a program that is cost-effective, equitable and respectful of other national goals as well as environmentally sound.

Climate policy builds upon pre-existing energy and environmental policy. In the United States, this foundation includes the Clean Air Act (CAA) and successive national energy policy acts as well as their policy counterparts at regional, state and local levels. The sulfur dioxide cap-and-trade program included in the 1990 Clean Air Act Amendments is a model for the application of that mechanism to the climate problem. More fundamentally, the core CAA principle of health-based air quality attainment -- a scientifically determined environmental goal to be met regardless of cost -- provides a model for the cap itself, even though the specification of GHG emissions targets and timetables necessarily entails international considerations. Most importantly, the CAA offers a clear legacy of success, in both achieving substantial and ongoing progress toward its stated goal of healthy air and doing so cost-effectively.

The energy policy legacy is not so positive, particularly when it comes to transportation energy use. More than three decades of alternative fuels policies have yet to lead to anything that can be termed meaningful progress (i.e., beyond limited niches). The RFS and LCFS approaches, even with their LCA-based GHG requirements, are outgrowths of energy policy. Even though an LCFS might be rationalized with legal reference to the CAA, structurally it has more in common with the prospective, promotional approaches of traditional alternative fuels policy. Neither the RFS or LCFS ensure with any reasonable confidence that emissions are limited to levels consistent with an economy-wide cap. Therefore, they cannot substitute for covering fuels under the cap with verifiable protocols for measuring and controlling or mitigating the GHG emissions associated with all fuels. In general, whether complementary measures are based on pre-existing policy or are created anew for climate policy, the better integrated they are into the cap, the more likely the overall policy is to achieve the ideals of environmental and economic effectiveness.

Because the majority (about 80%) of GHG emissions are from fossil fuel use, and because fossil fuel use can be measured with good accuracy, climate mitigation proposals specify the cap in terms of fossil carbon. Including transportation fuels in such a cap puts the majority of the sector's emissions under carbon management. GHG emissions at domestic refineries and other sources in the fuel supply system are covered under such a cap, as are any fossil fuel inputs to the domestic production of alternative fuels including biofuels, electricity or hydrogen.

Biofuels present an special problem because biogenic carbon is excluded from a fossil-based cap. Although this "renewability shortcut" is commonly used in official GHG inventories and in energy and climate models, it causes a gap in carbon accounting. The extent of the accounting error depends on the magnitude of uncapped emissions associated with biofuels plus the extent of leakage, particularly the indirect land-use change due to demand for biofuel feedstocks (and for bioenergy in general).

The question of how to treat biofuels in the context of a fossil-based carbon cap can be considered a problem of incomplete information. The carbon market is unable to address significant portions of biofuel-related emissions due to lack of specific data on GHG emissions from feedstock and fuel production facilities throughout the supply chain. The three-part approach outlined here can be seen as a way to address this information gap through careful accounting at the point of allowance submission and mechanisms to track uncapped emissions and mitigate leakage. It thereby exposes biofuel-related processes and facilities to a carbon price incentive tied to the economy-wide cap, creating a more complete carbon management framework for the transportation fuels sector.

Although the agricultural sector is not proposed for coverage under a cap, if some of its products -- such as biofuels or bioenergy generally -- substitute for capped fossil fuel, then their associated emissions must be accounted for if the integrity of the cap is to be maintained. The approach outlined here does so through a voluntary crediting mechanism, in that reporting of biofuel related emissions is needed only if the biofuel is used to claim a reduction in allowance requirements relative to the fossil fuel equivalent CO_2 otherwise emitted in the transportation sector. Thus, this approach does not extend the cap to the agriculture sector, but rather ensures that all emissions that occur in the capped transportation sector are adequately covered. Uncapped sources in the agriculture and forestry sectors remain uncapped in that their emissions are not regulated and only need to be reported if producers wish to claim credits for reducing refiners' allowance requirements in the capped transportation sector. A mitigation fund is used to address the remaining problem of ILUC.

Through coupling mechanisms such as those outlined here, the cap itself will become an effective driver of beneficial change in fuels. This approach contrasts with proposals based on pre-existing policy paradigms, which attempt to work around the shortcomings of the cap by using complementary measures that operate separately from cap-based GHG accounting. The extent to which the new options presented here might be useful for policy development is a question for further analysis and discussion, which this paper seeks to stimulate.

Appendix A

U.S. Transportation Sector GHG Emissions: Current Inventory, Projections and Market Structure

This appendix reviews transportation GHG emissions as reported in the EPA inventory and projected in the DOE *Annual Energy Outlook* (AEO), which form the basis of the sketch model described in the text. Also briefly described is the sector's market structure, which involves interactions among the multiple actors who provide and use transportation services. These actors include fuel providers, automakers and other equipment suppliers, public and private entities that plan, finance and operate transportation infrastructure, as well as consumers and other system users.

Current inventory

Figure A-1 (at end of this appendix) shows a breakdown of the 2005 U.S. GHG inventory. Transportation accounted for 28% of U.S. GHG emissions in 2005, the base year for the analyses given here. Although EPA has since published updated inventories with statistics through 2007, energy use and therefore GHG emissions have not grown much due to economic conditions and rising energy prices, and sector shares differ little from those shown in Figure A-1. Of the 2,009 $TgCO_2e$ emitted from the sector in 2005, 94% was CO_2 from fuel combustion.

Within transportation, automobiles (cars and light trucks) comprise the largest part of the inventory, accounting for 60% of GHG emissions. Medium and heavy-duty vehicles (largely freight trucks) accounted for 20%. Third largest was 9% for aircraft (largely commercial jets). Modal shares of GHG emissions parallel shares of sector energy use, which amounted to 27.5 Quads (10^{15}Btu), or 13 million barrels per day oil-equivalent in 2005.[96] End-use fuel consumption included 137 billion gallons of gasoline, 44 billion gallons of diesel fuel and 18 billion gallons of jet fuel in 2005. Ethanol consumption totaled 2.8 billion gallons (1.8 billion gallons gasoline energy-equivalent) in 2005, 99% of which was used in low blends (gasohol). Through 2007, fuel use in the U.S. transportation sector remained 95% petroleum based.

Each of the transportation modes has its own market structure, with emissions determined by the collective decisions of the various actors involved. For that reason, it is not possible to break emissions down further, for example, by allocating portions of automobile emissions separately among automakers, fuel suppliers and consumers. The interdependent relationship among the factors that determine emissions for each mode is illustrated by the triangle feeding into the car and light truck portion of the inventory. Similar multi-actor situations characterize the energy and GHG-related markets for other transportation modes.

Projected emissions

Table A-1 (also at the end of this appendix) summarizes relevant projections from recent editions of the AEO along with projections derived from it for the purpose of constructing the sketch model described in the text and from which the scaled (2005=100) levels given in Table 1 were derived. Although the AEO was again recently updated to reflect the 2009 economic stimulus package and revised economic and energy price assumptions, such changes are not consequential for purposes of the sketch model presented in this paper. The analysis was underway prior to that update and so retains use of the AEO 2009 early release projections issued in December 2008 (EIA 2008b).

As shown in the first line of Table A-1, EIA projected only slow growth in U.S. transportation sector CO_2 emissions through 2030. The 5% increase from 1,985 Tg of CO_2 in 2005 to 2,088 Tg in 2030 averages out to a compound growth rate of only 0.2% per year. This reduction in growth represents a marked contrast from previous projections as recent as those of the 2006 *Annual Energy Outlook* (EIA 2006), which projected transportation sector CO_2 of 2,667 Tg in 2030 and a average 2004-2030 growth rate of 1.3% per year. That made transportation the fastest growing sector in terms of CO_2 emissions, as it had been for a number of years. Recent historical growth in transportation CO_2 emissions was 30% over 1990–2005, for an average rate of 1.8% per year.[97]

Of course, one key reason for the lower growth projection is much higher oil prices. AEO 2006 projected an average 2010–2030 price for imported crude oil of roughly $46/bbl, while the AEO 2009 early release projects an average of $108/bbl for that period. The passage of stronger CAFE standards further dampens projected demand by constraining vehicle efficiency to levels higher than would have been projected based on even the higher fuel prices alone. And of course, the economic downturn has resulted in lower near-term economic activity levels than had been previously projected, taking a bite out of cumulative growth that is not recovered over the projection period. The fourth section of Table A-1 gives a "Higher vehicle efficiency only scenario" that reflects all of these changes and indicates transportation sector direct CO_2 emissions growing to 2,266 Tg by 2030, or 14% above the 2005 level implying 2005–2030 average growth of 0.5% per year.

What explains the remaining apparent reduction in transportation sector CO_2 emissions is DOE's use of the renewability shortcut, i.e., failure to account for all of the emissions impacts of biofuels that enter the fuel pool as driven by the RFS. As shown in the third and fourth lines of the first section of Table A-1, the AEO 2009 projections suggest a drop in average carbon intensity to a level roughly 8% lower by 2030 compared to the 2005 base year level of 67.4 gCO_2/MJ. This value represents only direct (end-use combustion) emissions and does not count biogenic carbon. Fossil-based emissions associated with the biofuels production chain do show up elsewhere in the AEO's industrial sector tallies. But non-fossil emissions, whether from N_2O or CO_2 from land-use change (or any lack of additionality in the bio- for fossil-carbon substitution) are not reflected.

Other elements of the sketch model projections are also given in Table A-1 as explained in the table notes and are not elaborated further here. A copy of the Excel workbook containing these tables and related calculations is available from the author by request.

Transportation sector market structure

Under a cap-and-trade policy, national GHG emissions would be placed on a declining trend with a legally binding constraint (the cap) falling collectively (rather than individually) on the covered sectors. For what is generally considered to be a comprehensive ("economy-wide" or "multi-sector") program, all sectors except agriculture are integrated under the cap. Although every end-use sector has its integration issues, the problem is particularly challenging for transportation.

This issue is illustrated by the auto sector breakout shown in Figure A-1. Cars and light trucks (the automobile subsector) account for 60% of the transportation total, and therefore about 17% of total (non-net) U.S. GHG emissions. The triangular representation of automobile emissions illustrates the fact that multiple actors are responsible for automobile emissions. The "three-legged stool" nature of transportation emissions -- that they are a *product* rather than a *sum* of factors influenced by different actors -- means that the sector cannot be cleanly subdivided for purposes of allocating either responsibility for reductions or allowances under a cap-and-trade program. A similar market structure exists for other transportation subsectors.

As shown in the figure, one way to depict this "factorization dilemma" is as a triangle with consumers (car drivers) in the middle. Most emissions (the downstream portion related to fuel use) occur at the vehicle due to consumers' fuel use. The points of the triangle correspond to the other major actors who significantly influence the factors behind auto emissions. All of these actors have financial relationships with consumers and other end-users of the transportation system:

- Consumers purchase fuel from fuel suppliers, now mainly the petroleum industry;
- Consumers purchase vehicles from automakers; and
- Consumers purchase (through taxes, other user fees and the price of many bundled services of the built environment) roads, parking, land and its associated uses and land-use patterns from the array of public and private actors involved in providing the infrastructures plus urban and regional plans that underpin travel demand.

This situation is why, even though all cap-and-trade proposals to date make fuel suppliers the point of regulation (POR), a more accurate way of characterizing such a POR is to say that fuel suppliers perform an accounting function on behalf of all actors in the sector (consumers, automakers, system planners and fuel suppliers), whose decisions collectively determine GHG emissions from transportation.

Thus, no simple price-quantity model fully captures the details of the real-world market decision making that influences transportation GHG emissions. Neither can a simple, single-market model adequately inform policy design for integrating the transportation sector into a carbon market under a cap-and-trade program. The distinct markets that determine transportation emissions can be seen as transactions (cash flows) from consumers (or other system users who are the source of demand) to the actors (suppliers of transportation-related services) at the tips of the triangle. This complex set of very different but interlocking markets is what defines the "real" market in which decisions shaping transportation sector carbon emissions are made. It is not simply reducible to the market for motor fuel, although that is one of the key markets and also a primary collection point for the user fees that support much (but not all) of the road system.

A market-based policy must reckon with all of these relationships. Focusing on just one (such as the fuel market price-quantity response) will lead to an incomplete and ineffective policy. Because the vehicle, fuels and system planning markets are so different, neither can one expect to easily levelize costs of carbon reduction among them or among these auto-related markets and the interlocking markets for other transportation and non-transportation sources. That is not to say that mechanisms for exploiting economic efficiencies cannot be developed. But it does call into question the idealistic notion that such diverse markets can be efficiently handled with a singular mechanism such as simple inclusion of fuels in the cap, even though such inclusion is likely to be essential for integrating the sector into an economy-wide cap-and-trade framework.

Ultimately, rationally managing fuel-related emissions under a cap entails a bookkeeping problem that is complex but which must be addressed to ensure environmental integrity, equity and economic efficiency for the transportation elements of climate policy. The special issues associated with biofuels that this paper explores are one aspect of the larger problem of mechanism design for transportation-climate policy.

Table A-1. Projected U.S. Transportation Sector Energy Use and CO_2 Emissions

($TgCO_2e$/yr unless otherwise noted)	**2005**	**2010**	**2015**	**2020**	**2025**	**2030**
CO_2 emissions, sector total[a]	1,985	1,904	1,932	1,955	1,991	2,088
relative emissions (2005=100)	100	96	97	98	100	105
implied carbon intensity[b] (gCO_2e/MJ)	67.4	64.8	63.9	63.5	62.5	62.1
apparent reduction in carbon intensity	--	4.0%	5.3%	5.8%	7.4%	7.9%
Upstream emissions due to imports from uncapped sources						
Conventional products[c]	116	90	94	85	85	87
Excess from unconventional[d]	68	100	146	168	195	220
Normalized (relative to total, 2005=100)						
Conventional products	5.9	4.5	4.7	4.3	4.3	4.4
Excess from unconventional	3.4	5.0	7.3	8.5	9.8	11.1
No efficiency improvement scenario						
Energy use, sector total[e] (Q/yr, HHV)	27.9	27.9	29.2	31.0	33.3	36.3
CO_2 emissions[f]	1,985	1,983	2,080	2,207	2,371	2,582
relative emissions (2005=100)	100	100	105	111	119	130
Higher vehicle efficiency only scenario						
CO_2 emissions[g]	1,985	1,983	2,039	2,075	2,150	2,266
relative emissions (2005=100)	100	100	103	105	108	114
AEO reference energy use[h] (Q/yr, HHV)	27.9	27.9	28.7	29.2	30.2	31.8
Light-duty vehicles	16.8	16.8	16.5	16.4	16.6	17.1
Medium and heavy-duty vehicles	5.0	5.1	5.8	6.1	6.5	7.2
Air	2.7	2.5	2.6	2.9	3.2	3.5
Other	3.3	3.5	3.7	3.8	3.9	4.0
Shares of sector energy use						
Light-duty vehicles	60.3%	60.3%	57.7%	56.3%	55.0%	53.6%
Medium and heavy-duty vehicles	17.9%	18.3%	20.3%	20.8%	21.4%	22.6%
Air	9.8%	8.8%	9.1%	9.8%	10.5%	11.1%
Other	12.0%	12.6%	12.9%	13.1%	13.1%	12.7%
Product and component imports[i] (Mbd)	2.85	2.20	2.30	2.09	2.08	2.14
(billion gallons per year)	44	34	35	32	32	33

Notes: In general, values are from DOE's *Annual Energy Outlook,* using AEO'08 revised edition (EIA 2008a) for 2005 and AEO'09 early release (EIA 2008b) for the projection years. Specific sources are as follows:

(a) AEO Table 18 (CO_2 emissions).

(b) Computed as simple ratio of projected direct (not full fuel cycle) CO_2 emissions to energy use.

(c) Derived by applying an upstream emissions factor of 20.2 gCO_2e/MJ (GREET 1.6) to the "Product and component imports" values described in note (i).

(d) Derived from AEO Table 21 (International Liquids) based on a full fuel cycle emissions factor of 121 gCO_2/MJ for heavy and unconventional resources from Farrell & Brandt (2006).

(e) Derived from AEO Table 7 (Transportation Key Indicators) assuming that new vehicle efficiency improvements cease after 2010.

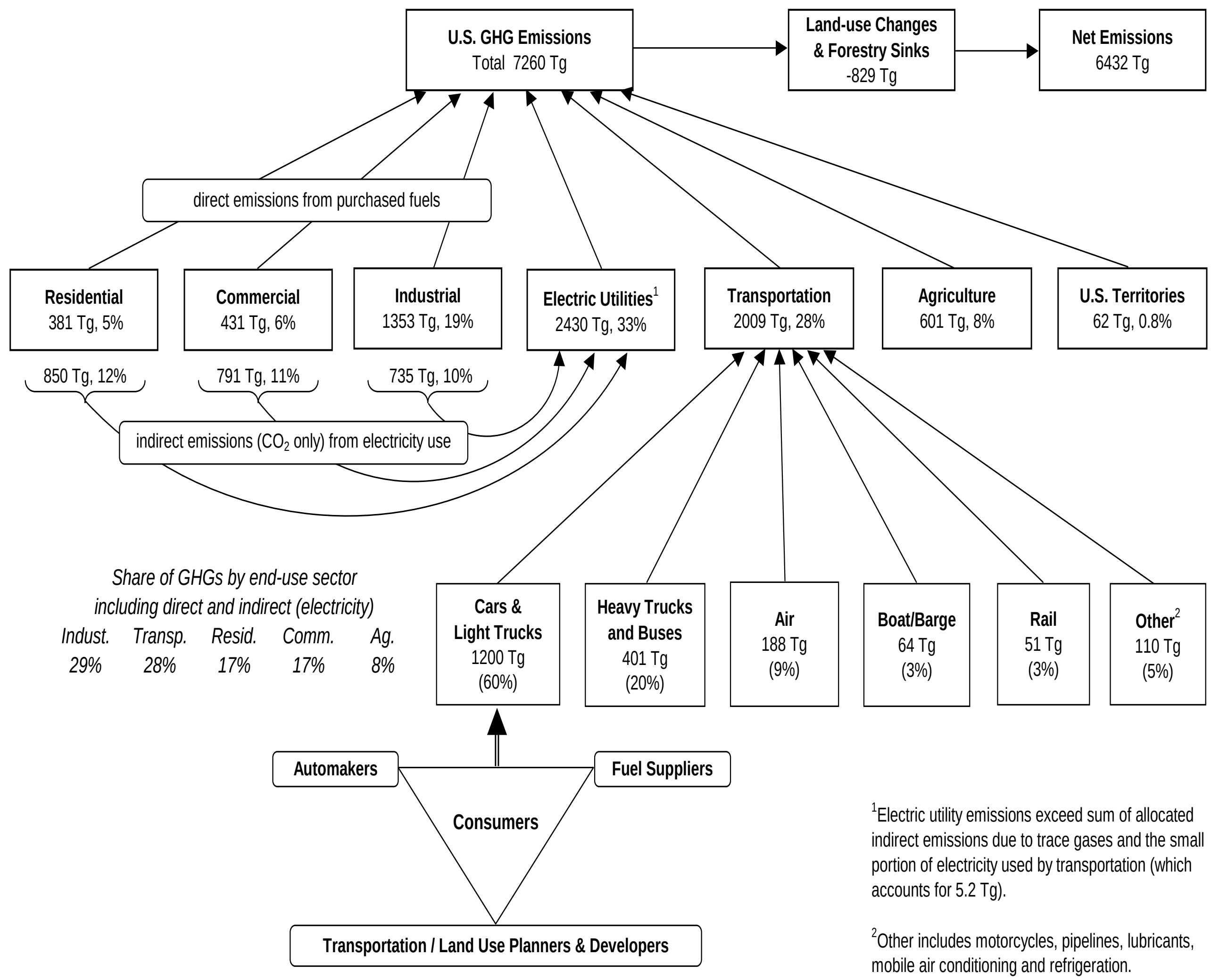
(f) Computed from projected energy use (e) assuming carbon intensity fixed at 2005 value.

(g) Computed from projected energy use (h) assuming fixed 2005 carbon intensity.

(h) Directly from AEO Table 7 (Q = Quad = 10^{15} Btu = 1.055×10^{18}J).

(i) Derived from AEO Tables 11, 21 and 127 counting only refined product and liquid fuel components imported from Canada, Latin America and the Caribbean Basin (Mbd = million barrels per day).

Figure A-1. U.S. Greenhouse Gas Emissions by Sector with Transportation Breakout, 2005



Source: U.S. EPA Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2005, Tables ES-7 & 2.17 (www.epa.gov/climatechange/emissions/usinventoryreport.html)
Values are given in teragrams (Tg = 10^{12}g); 1 Tg = 1 million metric tons, CO_2-equivalent.

Appendix B
Selected Review Comments and Responses

This appendix compiles particular comments on the review draft for which a specific response might help elucidate issues that may not have been resolved to everyone's satisfaction. Comments (in *italics*) are listed anonymously and may be paraphrased or combined when a similar issue was raised by multiple reviewers. This appendix does not list all comments, many of which were addressed in final revisions to the main text.

1. *Emissions inventories may or may not count biogenic carbon as a GHG emissions sink; conventional agriculture is not counted as a sink while afforestation can be. It seems strange for the proposed system to count agricultural CO_2 uptake as a sink for purposes of crediting it against the biogenic emissions that occur when a fuel made from the agricultural product is consumed.*

If a biofuel is used to replace a fossil fuel and claim credit for a GHG reduction, then full crediting and debiting of associated emissions fluxes is essential. The difference between agriculture for biofuel and agriculture for other purposes is that in the latter case, no claim of GHG reduction is being made and no fossil carbon is being displaced in a manner that yields an apparent reduction of CO_2 emissions under a cap.

2. *In the proposed FFAS system, why should a carbon uptake credit be given to a biofuel feedstock such as corn? No such credit is given when some of that same corn is used for feed or food. (In other words, why is such uptake considered additional for purposes of crediting against the cap?)*

The FFAS approach outlined here is not the same as treating biofuel use as a GHG emissions offset, even though it draws on some of the principles used for offsets policy. Unlike offset projects, biofuel and feedstock production is not treated as a circumscribed activity in an uncapped sector. Rather, a protocol is set up for verifiably tracing the substitution of biogenic carbon for fossil carbon within the commodity system and tracing associated uncapped emissions, which may occur in disparate locations. The FFAS system tracks absolute emissions levels, not emissions reductions, and so no baseline is established for which an additionality test is needed.* The displacement of land use from feed or food production to biofuel production, however, can cause emissions leakage, and the approach proposed here treats the concern as leakage rather than as an additionality problem.

It might be possible to define a purely offsets-based policy for reconciling biofuels with a GHG cap, in other words, to require allowance submission for the biogenic carbon in fuel but then treat all biofuel suppliers strictly as offset providers subject to the customary rules proposed for GHG emissions offsets. Analyzing such an system and assessing whether it might be superior to the approach outlined here might well be a worthy topic for future work.

3. *Counting biogenic carbon together with fossil carbon just compounds accounting complexity. In most cases, biogenic carbon is short-cycle carbon recently absorbed from the atmosphere and so the renewability shortcut is fine.*

The renewability shortcut is technically correct for lifecycle accounting, but is poorly suited for defining policies that provide incentives to entities that most closely control the disparate parts of

* As a practical matter, some of the GHG fluxes involved in feedstock production may themselves need to be estimated against assumed baseline conditions (e.g., for farm field soil carbon and N_2O emissions). However, the intent is to use location-specific measurements and modeling to estimate absolute net absolute fluxes tied to the feedstock for which FFAS ratings are being developed. Again, the result of the estimation is an emissions flux, not an emissions reduction for which an additionality concern might apply.

fuel lifecycle. Although it may be a convenience in modeling, it sets up a presumption of zero emissions that creates a high risk of incomplete or incorrect information about actual emissions for policy administration.

4. *Rather than basing the approach on conventional fuel equivalent carbon, why not require refiners to cover the direct carbon content of all transportation fuel distributed, regardless of fuel type, except to the extent its FFAS rating demonstrates lower net uncapped emissions?*

That would be a technically sound way to implement the general approach outlined here, and it would be more scientifically precise (although the difference is small). On the other hand, conventional fuel carbon equivalence is more exact for holding biofuel producers harmless competitively, so that the pricing of unrated biofuels relative to the fossil fuels they displace remains unchanged from what it is without a carbon cap. Either approach will accomplish the crucial goal of preventing the inclusion of transportation fuels in the cap from driving large emissions leakages due to commodity displacements tied to fuel demand. Ultimately, this question presents a policy judgment that will need to be worked out among stakeholders.

5. *The suggested point of regulation (POR) is further downstream than seen in cap-and-trade proposals to date, but most economists suggest that the best coverage is achieved by placing the POR as upstream as possible.*

It does not appear that most economists who have recommended cap-and-trade policy designs have looked carefully at the structure of transportation markets. Only at the point of finished fuel distribution is it possible to fully ascertain the characteristics of distributed fuels, which is why EPA has used that POR for existing fuels composition standards and why it is recommended here.

6. *The approach aspires to strictly measurement-based GHG accounting, but this seems impossible to do in practice. Models may still need to be used based on scientific principles and limited field data.*

This point is well taken. However, there is a big difference between circumscribed use of models, say, to characterize N_2O emissions from a given group or farms or district, and the sweeping use of modeling that characterizes LCA-based regulation as seen in the EPA RFS and CARB LCFS regulations. LCA modeling, which attempts to address an entire pathway -- and so invites an adverse selection risk by relying on generic as opposed to producer-level data -- would not be used. Models specific for a given impact would be used to fill in data gaps, e.g., for soil-related fluxes for which direct measurements are limited. For example, data and modeling techniques developed in USDA's GRACEnet program could be used to develop best-available-resolution field-level estimates for use in the FFAS system. While not immune from adverse selection issues, the risk is lower because of both the voluntary nature of the FFAS and the inherently facility-specific policy design.

7. *Why do you claim that lifecycle analysis is not compatible with GHG emissions accounting under a carbon cap, and why wouldn't it in fact be better to use the complete accounting framework provided by LCA ?*

LCA fails to distinguish capped from uncapped sources and in combination with a cap would entail double-counting emissions from capped parts of the fuel supply chain. LCA could be used to guide the design of an emissions tracking system for use with a cap, but such a fuel cycle analysis would have to be deconstructed to separate capped from uncapped emissions, and also domestic from foreign emissions, in order to determine allowance requirements in a manner consistent with the coverage intent of cap-and-trade policy. The process of so deconstructing LCA would make it much like the FFAS system proposed here. Another difference is that LCA may also examine future impacts (as seen, for example, in EPA's proposed lifecycle scenarios for the RFS), whereas a cap uses "ABC" (annual basis carbon) accounting, relying on explicit banking and borrowing or market mechanisms for handling temporal risks.

Philosophically, the use of LCA to regulate fuels can be criticized as being premised on a fallacy of reification (or "misplaced concreteness"). That is to say, it treats an abstract construct (namely, a fuel's lifecycle GHG intensity) as if it were a concrete physical property (such as a fuel's chemical composition). For biofuels, the dominant emissions of concern occur at fields and facilities; those are the physical emissions that must be tracked to ensure regulatory and market transparency. GHG intensity is purely notional; it cannot be measured in a concrete, repeatable way as can, for example, regulatory limits on sulfur or other chemical and physical specifications required in fuel regulations. The degree of abstraction on which lifecycle GHG impact metrics are based is apparent in EPA's thorough and heroic proposal for LCA-based regulation in the RFS2 NPRM, which clearly illustrates how the results are highly dependent on numerous modeling assumptions.

8. *The low GHG intensity case in Table 1 uses an ILUC impact of 30 g*CO_2*/MJ for corn ethanol, but this value is too high for the low end of the range given the extent to which the scientific community is still debating the issue.*

The uncertainties involved may be much wider than the range given here for purely illustrative purposes. Moreover, key aspects of the debate are not just about the magnitude of impact, but the degree of attribution to particular agricultural systems such as U.S. corn production. Again, the purpose here is not representation but rather illustration for the purpose of motivating the need for different policy options. That being said, EPA's proposed estimate of 60 gCO_2/MJ falls roughly in the middle of the 30–100 gCO_2/MJ illustrative range used here, and no claim is made regarding any statistical confidence associated with such a range.

9. *Why should ILUC emissions associated with biofuels be treated differently than upstream fossil emissions that also occur overseas in countries without a cap? For example, the paper states that upstream fossil emissions "might be best handled by mechanisms designed to address trade-related impacts, such as border adjustments or other policies having an ultimate goal of encouraging countries with which we trade to also adopt carbon caps." Why not similarly recommend for biofuels ILUC that the United States should encourage affected countries to adopt forest preservation programs?*

The key difference between biofuels and fossil fuels is that no one claims that the latter reduce GHG emissions. It is unquestionable that fossil fuel CO_2 emissions, wherever they occur and unless recaptured and sequestered, contribute to atmospheric GHG accumulation and so they are a primary target of climate policy. Largely on the basis of the renewability shortcut, it has been claimed that biofuels reduce GHG emissions and so this claim is subject to quantitative scrutiny, including for leakage effects such as ILUC. In any case, most U.S. climate policy proposals do contain provisions to encourage forest preservation both domestically and in other countries, including targeted provisions for reducing tropical deforestation. Nevertheless, the point is well taken and may warrant further analysis of how well the approach outlined achieves a balanced treatment of biofuels and fossil fuels.

10. *The option of financing the Land Protection Fund (LPF) to mitigate biofuel ILUC with some form of tax on petroleum or petroleum allowance trades is deeply flawed. There is no reason to expect the magnitudes to match and worse, shifting the charge from biofuels to petroleum will aggravate the adverse impacts of biofuels.*

It is true that in economic efficiency terms, taxing petroleum to finance the LPF is ill targeted. This option, which is identified but not necessarily recommended among the set of options identified, might be a way to address the multiple national objectives in addition to climate protection that influence energy policy.

ENDNOTES

[1] EPA (2007), Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2005, Table 2.3. Other statistics on U.S. GHG emissions are based on this or the next (EPA 2008) edition of the inventory unless otherwise noted.

[2] See, e.g., Greene and Schafer (2003).

[3] Cap trajectory based on reduction targets of a 14% below the 2005 levels by 2020 and 83% below the 2005 levels by 2050, as proposed by the Obama Administration when releasing the budget proposal of Feb. 26, 2009.

[4] EPA (2009a) RFS2 NPRM, §VI.A.1, FR 74(99): 25021.

[5] The author is unaware of published policy analyses that rigorously make the case for an LCFS or other form of lifecycle-based fuel regulation, even though it has been increasingly advocated in recent years, e.g., by Greene (2004) for a RFS with lifecycle performance criteria and Sperling & Yeh (2009) for the LCFS. On the other hand, critical analysis is started to emerge, e.g., Holland et al. (2009).

Perhaps the earliest published references to LCA-based fuels regulation are DeCicco & Lynd (1997), which identified the option of extending conventional motor fuel composition standards to "standards specifying a maximum full-fuel-cycle GHG factor (for example, in grams of carbon-equivalent per joule of energy content)," and DeCicco & Mark (1998), which recommended "full fuel cycle (FFC) GHG standards or a FFC GHG emissions cap for motor fuels." The author's recollection is that these suggestions were based on a simple belief that such an approach would be effective rather than in-depth analysis of either how such standards could be implemented and administered or their economic effectiveness. The author recalls that the conception for such an approach grew from discussions with fuel developers, agency officials and others in 1994-95 during the Federal Advisory Committee ("Car Talk") convened by the Clinton Administration to identify policy options for reducing GHG emissions from automobiles.

[6] See, e.g., Stavins (2008).

[7] For discussions of transportation sector policy design considerations, see EDF (2007), p. 9, and USCAP (2009), p. 21.

[8] Although official U.S. GHG emissions inventories tabulate direct CO_2 emissions from biofuels, they are excluded from the national tally. See, e.g., EPA (2008), Table 2.1, Note (b) "Emissions from International Bunker Fuels and Wood Biomass and Ethanol Consumption are not included in the totals."

[9] See, e.g., McCarl (2008a), who in reviewing conventional approaches notes the commonplace assumption:

> Direct net emissions from biofeedstock combustion are virtually zero because the carbon released is recycled atmospheric carbon. As such this combustion may not require electrical utilities or liquid fuel users/producers to have emissions permits.

[10] EPA (2009a) RFS2 NPRM §VI.C.1, FR 74(99): 25401.

[11] Wang (1999). Versions of GREET and similar models are being widely adapted for use in regulatory analysis, e.g., by CARB and EPA, and by consultancies and universities who have been performing fuel cycle analyses. GREET uses survey-based emissions factors; for biofuels, it applies these factors to estimate combustion emissions of CO_2 , CO, VOC, CH_4 and other carbon-based gases. Its calculations then internally credit biogenic CO_2 based on a carbon mass balance of these emissions, so that its results report no net CO_2 emissions from biogenic carbon.

[12] See, e.g., Olander (2008); OQI (2008). Establishing additionality requires careful assessment of an action (such as production and use of a biofuel) against a baseline condition representing the GHG emissions without the action. Estimating leakage also requires careful analysis, accounting for economic substitution and trade effects when an action has market impacts that reach beyond its geographic and temporal scope.

[13] Gullison et al. (2007).

[14] Reilly & Asadoorian (2007), p. 190.

[15] Naylor et al. (2007).

[16] Unnasch et al. (2009), p. i.

[17] Searchinger et al. (2008).

[18] Geist and Lambin (2002).

[19] Moutinho and Schwartzman (2005); Gullison et al. (2007). Canadell et al. (2007) suggest a lower estimate of 15% for the share of global CO_2 emissions related to tropical deforestation, not because the magnitude of those emissions has declined, but rather because emissions from fossil fuel use have grown more rapidly in recent years.

[20] Righelato and Spracklen (2007).

[21] EISA (2007), Title II, §201.(1).

[22] ACESA (2009), Title V, §551.

[23] Schwarzenegger (2007), Item 4.

[24] CARB (2009), p. IV-17.

[25] See, e.g., Delucchi (2008).

[26] While not intractable and perhaps a useful follow-on step from this discussion paper, developing representative tallies of capped vs. uncapped emissions for existing fuel cycles would involve deconstructing models such as GREET and then re-assembling the intermediate results to discriminate emissions for entities along the supply chain.

[27] EIA (2008a), Table 18, transportation total value for 2005. Of this 1,985 $TgCO_2$, 98% (1,948 $TgCO_2$) are from combustion of petroleum fuels.

[28] In his February 26, 2009 budget proposal, the President stated a goal to "… reduce GHG emissions approximately 14% below 2005 levels by 2020 and approximately 83% below 2005 levels by 2050." The intermediate 2030 target used here is based on an interpolation as shown in Figure 1.

[29] Derived from numbers in EIA (2008c), Slide 10, adjusting for RFS credits.

[30] EIA (2008c), Slide 18.

[31] See, e.g., Crutzen et al. (2007) regarding agricultural N_2O and Searchinger et al. (2008); Fargione et al. (2008) regarding CO_2 from land-use change alone.

[32] Grandfathered ethanol refers to that produced from existing facilities, meaning facilities for which construction had started prior to the December 19, 2007 enactment date of EISA and therefore for which the minimum 20% lifecycle GHG intensity reduction requirement does not apply.

[33] Traditional fuel cycle analysis does not count economically induced impacts such as ILUC. Whether such emissions should be addressed in lifecycle-based regulation is disputed, as is the magnitude of the impact itself. A letter from one group of analysts says that ILUC impacts should not be included in a LCFS (Simmons et al. 2008). A different group letter says ILUC should be included, indicating a range of 100–200 gCO_2e/MJ for corn ethanol (Delucchi et al. 2008); such analysts generally agree that only waste-based feedstocks are immune from such impacts. The other impact that could significantly raise biofuels lifecycle GHG intensity is N_2O from farm fields. Crutzen et al. (2007) suggest that these emissions could be 3–5 times higher than the default values used in traditional LCAs; that would increase N_2O impacts from a typical value of 20 gCO_2e/MJ to a range of 60–100 gCO_2e/MJ.

[34] Note that care must be taken even when utilizing fuels from products now considered wastes. Once such "wastes" gain value in a carbon market, they will no longer be wasted and so an incentive could arise to generate more of them, resulting in some potential for increased land-use pressure accordingly.

[35] For conventional refined product imports, estimates were derived from EIA (2008b) AEO 2009 Tables 11 and 127, counting only imports from Canada, Latin America and the Caribbean Basin. The associated upstream emissions were estimated by applying a factor of 20.2 gCO_2e/MJ (GREET 1.6). For imported unconventional imports (crude, syncrude and the additional upstream impacts of refined products derived from unconventional resources), estimates were derived from AEO 2009 Tables 21 and 127, applying an *additional* emissions factor of 32.3 gCO_2e/MJ based on Farrell and Brandt (2006), Figure 1. See appendix for detailed calculations.

[36] Ashcroft & DeCicco (2008).

[37] See Gnansounou et al. (2008), p. 15, for definitions of attrributional vs. consequential LCA.

[38] *op. cit.*

[39] See discussion of fuel components and what constitutes "finished fuel" in EPA (2009a) RFS2 NPRM, pp. 24960ff.

[40] Code of Federal Regulations, Title 40, Part 80, "Regulation of Fuels and Fuel Additives," Definitions section (accessed 6 Feb 2009 via www.gpoaccess.gov/cfr/index.html).

[41] See, e.g., Boadway & Wildasin (1984), p. 65.

[42] See CARB (2009), Table ES-8.

[43] See., e.g., Willey & Chameides (2007).

[44] The example is derived from data presented in the Mueller et al. (2008) of the Illinois River Energy Center and the farms that serve it. That study presents a conventional GREET-based lifecycle analysis; for our purposes, we do not need or use the lifecycle analysis results *per se*, but rather the input data reported in the study.

[45] A spreadsheet detailing these and other illustrative calculations used here is available from the author upon request; for this example, we assume a biomass carbon content of 45% of dry mass.

[46] The estimates of total and uncapped emissions from production of nitrogen fertilizers used in this example are taken from CARB (2008), Table 2.02, assuming that all of the fertilizer production facility CO_2 is capped and that its N_2O and CH_4 emissions are uncapped. These estimates are then applied using the Illinois River Energy Center farm draw case study nitrogen application rate from Mueller et al. (2008), p. 19.

[47] See, e.g., Smeets et al. (2009) for a general discussion and Mueller et al. (2008) for a discussion of the farm-specific estimates used here.

[48] From Mueller et al. (2008), p. 26, using a N_2O factor of 15 g/bu, which with a global warming potential of 310 implies N_2O emissions of 4.8 kgCO_2-eq/bu, from which the tabulated value was derived. This value is similar to standard factors similar to what has been used for IPCC climate inventory calculations. However, some analysts believe that N_2O emissions from agriculture are as much as 3–5 times higher (see, e.g., Crutzen et al. 2007).

[49] Mathews (2008).

[50] Following GREET conventions, Mueller et al. (2008) do not report CO_2 emissions from fermentation; the value given here was derived by the author from a carbon balance calculation using the feedstock, product and co-product data reported by Mueller et al.

[51] See, e.g., discussion in EPA (2009a) RFS2 NPRM, §VI.B.5.b.i, FR 74(99): 25029.

[52] Mueller et al. (2008).

[53] IEA (2004), Chapter 6, "Land use and feedstock availability issues."

[54] Searchinger et al. (2008).

[55] RFA (2008).

[56] Moutinho and Schwartzman (2005).

[57] See, e.g., Olander (2008); Willey & Chameides (2007), Chapter 10 and Appendix 20. Here we use "leakage" in a generalized sense of the term, including both leakages resulting from trade (and which can in principle be observed through and therefore estimated on the basis of monetized transactions) as well as "activity shifting" (which may not be monetized, as in ripple effects of land-use change caused advancing subsistence agriculture that is in turn driven by other substitutions). Both forms of leakage are relevant to assessments of biofuels and other forms of bioenergy.

[58] Fargione et al. (2008).

[59] See, e.g., Rajagopal and Zilberman (2008).

[60] CARB (2009), pp. IV-19ff.

[61] Searchinger et al. (2008), Table 1.

[62] Gasoline and other traditional motor fuels also have associated indirect effects; in general they appear smaller than those associated with biofuels but they can be significant for unconventional fossil resources. Once one expands the scope of lifecycle analysis to induced effects, it can become very broad indeed. An arguments can be made to include the impacts of military action for securing access to petroleum resources (Unnasch et al. 2009).

[63] Delucchi et al. (2008) letter to CARB.

[64] Simmons et al. (2008) letter to CARB.

[65] CARB (2009), Table ES-8.

[66] See EPA (2009a, 2009b) and related documents and links on http://www.epa.gov/otaq/renewablefuels/index.htm.

[67] EPA (2009a) [FR 99(74): 25041] lists a 30-yr, 0% international land-use change impact of 1,910,822 gCO_2 per 10^6Btu, which converts to 1,811 gCO_2e/MJ, which divided by 30 years yields the 60 gCO_2e/MJ value cited in the text.

[68] By metric used directly for environmental regulation, we mean a quantitative measure, such as a concentration of a gas or other chemical (e.g., ppm of sulfur in fuel, arsenic in water, etc.), a quantity of observable emissions (such as NOx emissions from a tailpipe or power plant stack), or the like that can unambiguously be associated with the object of regulation (such as a product or facility) through well-defined and repeatable measurement procedures. Less well-defined metrics are commonly used in the development of regulations (such as models of ozone formation and transport that inform the overall stringency levels required for stationary and mobile source emissions standards), but are rarely used for directly specifying regulatory requirements.

[69] Moutinho and Schwartzman (2005); Gullison et al. (2007).

[70] Santilli (2004); Mollicone et al. (2007).

[71] See, e.g., Gibbs et al. (2007); Schwartzman et al. (2007); Cabezas & Keohane (2008).

[72] For example, see requirements as given in §764, "Offset Credits for International Forest Carbon Activities," of the House Energy and Commerce Committee climate bill discussion draft (October 7, 2008). More generally, see

[73] See, e.g., Daigneault & Fawcett (2009), which estimates over 100 $TgCO_2$ of international forest offset potential in non-OECD countries at carbon prices of less than \$10/tonCO_2.

[74] CCAR (2007), p. 10.

[75] IPCC accounting officially excludes CO_2 from combustion of biogenic materials; the general guidance is:

> Carbon dioxide from the combustion or decay of short-lived biogenic material removed from where it was grown is reported as zero in the Energy, IPPU and Waste Sectors (for example, CO_2 emissions from biofuels, and CO_2 emissions from biogenic material in Solid Waste Disposal Sites (SWDS)). In the AFOLU [agriculture, forestry, land use] Sector, when using Tier 1 methods for short lived products, it is assumed that the emission is balanced by carbon uptake prior to harvest, within the uncertainties of the estimates, so the net emission is zero. Where higher Tier estimation shows that this emission is not balanced by a carbon removal from the atmosphere, this net emission or removal should be included in the emission and removal estimates for AFOLU Sector through carbon stock change estimates. (IPCC 2006, p. 1.6).

The guidance, does, however, note that "CO_2 emissions from the use of biofuels should be reported as an information item for [quality control] purposes" (*loc. cit.,* note 6).

[76] Fargione et al. (2008); Gibbs et al. (2008).

[77] See, e.g., the discussion in CARB (2009), pp. IV-21ff.

[78] Reilly & Asadoorian (2007).

[79] EPA (2007), Table ES-2. Calculating CO_2 emissions from bioenergy sources is straightforward based on the well-known chemical characteristics of biomass and biofuel products.

[80] USDA (2009) addresses the cost exposure and potential benefits to the agriculture from a cap-and-trade program based on an evaluation of the impacts of ACESA (2009); it addresses offsets not the impacts of mechanisms such as those outlined here, which have not yet been introduced into the policy development mix, although it notes that bioenergy programs could increase agricultural sector income.

[81] The energy security surcharge would be a disincentive to trading away of transportation sector reduction requirements into other sectors of the carbon market, and so dampen the liquidity of the overall market. However, this may not be a bad thing. Transportation's relatively weak price responsiveness has raised concerns that including the sector in the cap would drive up allowance prices compared to a stationary-only program. The differential created by an energy security surcharge would allow non-transportation trades to occur at a lower price than transportation trades.

[82] Leiby (2007) estimates \$13.60/bbl (2004\$), which inflated to 2005\$ and rounded yields the \$14/bbl given in the text. A similar level (\$12.68/bbl) is proposed in the RFS2 rule (EPA 2009a, §IX.B.2, FR 74(99): 25092). These most recently proposed values for the external cost of U.S. oil import dependence, which imply roughly 29¢/gal of gasoline, are notably higher than those of prior recent rules, such as the 9¢/gal used in the NHTSA (2006) CAFE rule.

[83] Sperling and Yeh (2009); Sperling and Gordon (2009, p. 149) call cap-and-trade a "nonsolution."

[84] See, e.g., Small and Van Dender (2007) for a broad review; however, these authors also fail to distinguish the elasticity of GHG emission from the elasticity of energy demand.

[85] Note that just because a fuels performance standard is based on a nominally objective metric, such as lifecycle GHG intensity, does not mean that it is a market-based policy for the environmental outcome of concern, which is actual emissions rather than the emissions intensity of a highly composite factor representing a complex system. Moreover, close inspection of LCFS proposals to date shows that they are not actually "technology neutral." Instead, they rely exclusively on modeling of pre-determined feedstock-process-fuel pathways and are highly dependent on default values for these pathways, including assumptions based on *a priori* analysis and negotiation. Although it is argued that such a policy will provide an incentive for fuel suppliers to substitute real-word data for modeled process and pathway defaults, how this works out in practice is yet to be seen.

[86] Technology proponents often argue about the need to overcome "barriers" to new technology and might point to the poor U.S. experience with alternative fuels as evidence of very inelastic market response. However, the technology-based policies tried to date have not been truly market-based in terms of environmental outcome; they have all been premised on certain prospectively identified technologies as being the mechanisms for emissions reduction. "Barrier" theory (itself with no empirical basis for the markets in question) does not provide evidence that the market would fail to respond to a policy that directly constrains or prices the environmental outcome (GHG emissions), which has remained an externality that U.S. policy has yet to "internalize" in any meaningful way.

[87] See, e.g., McNutt and Rogers (2004). Sperling and Yeh (2009) also recount the failure of the "technology du jour" approach to fuels policy, although they still promote technology-forcing policy, now in the form of a LCFS.

[88] Sperling & Gordon (2009, p. 96) state, "Brazil isn't an energy model. The Brazilian situation is unique. It's not replicable."

[89] See, e.g., the discussion in Doornbosch and Steenblik (2007), pp. 39ff.

[90] Mathews (2008).

[91] EPA (2009a) RFS2 NPRM, §VI.B.1, FR 74(99): 25022.

[92] This reasoning (that policymakers need not concern themselves with discriminating fuels *per se*) seems to run counter to the presumption that such discrimination is necessary. For example, in its ANPRM on regulating GHGs under the CAA, EPA (2008c, §VI.D.2, FR 73(147): 44474-75) notes that:

> EISA recognizes the importance of distinguishing between renewable fuels on the basis of their impact on lifecycle GHG emissions. Nevertheless, EISA stops short of directly comparing and crediting each fuel on the basis of its estimated impact on GHG emissions. … Without further delineating fuels on the basis of their lifecycle GHG impact, no incentive is provided for production of particular fuels which would minimize lifecycle GHG emissions within the EISA fuel categories.

The agency went on to request comment on the importance of distinguishing fuels beyond the categories established in EISA (the context in which its remarks were made). However, this apparent need is based on a presumption of fuels themselves as an object of regulation, as opposed to facilities where fuel and feedstock production -- and the emissions of concern -- actually occur.

[93] See Loeb (1990), whose critical review of the lead phase-down still finds the program to have been cost-effective.

[94] CARB (2009), p. ES-26.

[95] Holland et al. (2009).

[96] Fuel consumption statistics in this paragraph are from Davis et al. (2008), Tables 2.2, 2.3 and 2.6.

[97] EPA (2007), Table 3-3.

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