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GHG Trading Framework for the U.S. Biofuels Sector

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Abstract: Substitution of petroleum fuels with biofuels such as ethanol and biodiesel has been shown to reduce greenhouse gas (GHG) emissions. These GHG reductions can be traded in the emerging carbon markets, and methodologies for quantifying and trading are still being developed. The main challenges in developing such GHG trading framework are analyzed. An outline of such a framework is presented that depends on the life cycle assessment of GHG reductions, along with a combination of project specific and regional standard performance measures. The advantages of assigning GHG property and trading rights to biofuel producers are discussed. At carbon prices of $10 per metric ton, estimated additional revenues to biofuel producers range from $ 17 to 64 million dollars per billion gallons of corn ethanol and cellulosic ethanol respectively.

Biofuels for transport applications are considered attractive because of their potential contribution to improving energy security, reducing greenhouse gas (GHG) emissions, and increasing rural incomes. Substituting biofuels such as ethanol from corn and biodiesel from vegetable oils for gasoline and diesel can reduce GHG emissions by 20%- 40% on an average. The second generation biofuels derived from cellulosic materials are considered even more promising because of their significantly higher GHG reductions which range from 60% to 120%. (Moomaw and Johnston, 2007; Wang, et al., 2007). Development of GHG markets enables monetizing and trading the environmental attributes of biofuels, specifically the reductions in GHG emissions (Gururaja, 2005). Considering the high volumes of liquid fuels used and the growing amount of biofuel use in US transportation, the GHG market implications of biofuel use are 'potentially very large' (Capoor and Ambrosi, 2007). For example, corn ethanol use in transportation in the US has increased from 0.9 billion gallons in 1990 to 6.5 billion gallons in 2007 and expected to exceed 10 billion gallons by 2012 (RFA 2007). Simultaneously, the global trade in GHG permits increased from ten to sixty billion dollars between 2005 and 2007, and carbon prices were as high as $45 per metric ton in the EU markets (Capoor and Ambrosi, 2007; Point Carbon, 2007).

Efforts are ongoing in the EU to develop a GHG trading framework and approved methodologies for biofuels. The GHG credits created from biofuel use can also potentially be traded under the system created by the Chicago Climate Exchange® (CCX®) in the US (CCX, 2007a; Gardner, 2007). Under the CCX trading platform carbon credits are generated from various types of projects in agriculture (e.g. reduced tillage), forestry, methane digesters, renewable energy projects and fuel switching. These carbon credits are then certified under CCX protocols, the certified GHG credits can then be sold to other members who are required to meet their mandated levels of GHG reductions. Using liquid biofuels in transportation can potentially be eligible for CCX GHG credits because it would be a form of fuel switching, from fossil fuels to renewable fuels. Some projects that are eligible under EU emissions trading scheme are said to

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be eligible under CCX (CCX, 2007b). However trading GHG benefits from biofuels is likely to be more challenging in the absence of an appropriate trading framework that establishes property rights over such GHG benefits and then help quantify the tradable GHG benefits. A GHG Trading Framework (GTF) for biofuels needs to address the following questions.

1. What is the appropriate method for quantifying the GHG benefits from biofuel use? How to handle the potentially large variations in GHG emissions because of variations in feedstocks, feedstock production practices, final biofuel products, conversion technologies, and vehicle technologies?
2. What quantities of GHG reductions below the baseline qualify for trading in the emissions market? In other words, what proportion of the GHG benefits satisfies the 'additionality' principle?
3. Who gets the property/trading rights to reductions in GHG from biofuel use?
4. How to design verification and monitoring mechanisms for measuring GHG reductions as well as leakages?
5. How to design incentive mechanisms that are compatible with relative contribution of various participants in the life cycle of biofuels?

These issues are discussed briefly before outlining a proposed GTF for the US biofuels sector. The proposed GTF directly addresses the first four questions, but depends on market mechanisms to allocate the monetized GHG benefits among various participants in the biofuel life cycle, namely feedstock producers, fuel producers, blenders, and final consumers. The proposed GHG trading framework is consistent with the methodologies used under the Clean Development Mechanism (CDM - supervised by United Nations Framework Convention on Climate Change) in the EU and other methodologies followed by CCX in the US (CDM, 2007a, 2007b; UNFCCC, 2007; WBCSD, 2007; WRI, 2007). The key question is 'what constitutes ownership of GHG credits in the US biofuels sector'? A property rights structure that would suit the US biofuels industry is proposed (Kumarappan and Joshi, 2008; Sims, 2003). While most of the following discussion uses ethanol to illustrate the proposed GHG trading framework, the analysis can easily be extended to other biofuels such as butanol, methanol, biodiesel, and biomass-Fisher-Tropsch liquids.

2. Issues in Creating Tradable GHG Credits from Biofuel Use in Transportation

What is the Appropriate Method for Quantifying the GHG Benefits from Biofuel Use?

Biofuels reduce the GHG emissions compared with gasoline and diesel, but do not eliminate all the emissions. GHG emissions from biofuels are less than that of fossil fuels on a life-cycle basis, because carbon dioxide is sequestered during the growth phase of the biomass (corn crop, cellulosic materials, algae) that is used to produce biofuels. However, additional GHG emissions occur from the use of fertilizers, pesticides, and machinery use in the feedstock production process, use of fossil energy in the biofuel conversion process and in the storage, transportation, and distribution of feedstocks and biofuels. Hence, the emission reductions from biofuel use should be quantified by comparing the life-cycle GHG emissions of biofuels with that of a baseline fuel (fossil fuel, such as gasoline). Life cycle methods have been used for biofuel policy making in most of the OECD countries including the US (OECD, 2008). For example, the

US Energy Independence and security Act of 2007 defines conventional and advanced biofuels based on their life cycle GHG reductions (BRDB, 2008; EISA, 2008).

While life cycle assessment (LCA) is relatively simple in concept, developing LCAs whose estimates are universally acceptable is very difficult. The challenges in LCA include choosing appropriate system boundaries, choice of representative processes and pathways to be modeled, accounting for input interdependencies, data representativeness and quality on inputs and outputs (including emissions), and evaluation of environmental impacts (Joshi, 2000). These issues get even more complex in the case of comparative LCAs of biofuels and fossil fuels because of multiplicity of pathways, products, interdependencies and co-products. A large number of feedstocks such as corn, sorghum, wheat, and cellulosic (herbaceous, woody, and waste) biomass can be used in biofuel production. The cultivation practices, types of inputs used and yield of these feedstocks vary significantly across geographical locations, depending on producer decisions, production process, relative input-output prices, soil quality and local climatic conditions. The feedstock to fuel conversion technologies (e.g. biochemical versus gasification of cellulosic biomass) use different levels of energy that contribute to different levels of GHG emissions. The energy sources at the biofuel production facility can range from coal and natural gas to biomass power; multiple energy sources could be used in the same facility as well. The production of various co-products needs to be accounted (e.g. lignin used for electricity production in cellulosic biorefineries). The vehicles that run on biofuels can vary in terms of their power-trains (e.g. conventional spark ignition vehicles, displacement on demand vehicles, hybrids, or flexible fuel vehicles) and biofuel blend levels (E10, E85, E100). Each combination of feedstock, biofuel production process and final vehicle use and underlying assumptions would lead to different levels of lifecycle GHG emissions. Hence, all types of ethanol do not yield the same level of GHG reductions; failure to recognize these differences might also lead to ‘leakage’ of GHG (increase in GHG emissions) elsewhere in the supply chain.

A large number of LCA models have been developed that compare life cycle GHG emissions for a number of these feedstock-fuel-vehicle combinations (MacLean and Lave, 2003; Wang, 2005). Among the various models, a model developed by Argonne National Laboratory (ANL), called ‘Greenhouse gases Regulated Emissions and Energy use in Transportation’ (GREET) is emerging as a generally accepted standard model that is being widely used by policy makers and industry in the U.S. (ANL, 2007; GM, 2001; GM, et al., 2002). GREET model is also being used by California Air Resources Board in developing its new low carbon fuel standards (CARB, 2008). Major advantages of the GREET model are that it is publicly available, free, comprehensive (i.e., it covers a large number of feedstock-fuel-vehicle pathways), well documented and transparent, flexible, and user friendly. Users can estimate changes in GHG emissions under different scenarios by changing specific parameters and input combinations relatively easily, and can also carry out uncertainty analyses using Monte-Carlo simulations (ANL, 2007; Wang, 2005). This model can accommodate the above said differences in feedstocks, production processes, blend levels, transportation and also indirect emissions due to land use changes.

Which GHG Reductions Qualify for Trading in the Market?

While substituting fossil fuels with biofuels can reduce GHG emissions, only that portion of GHG benefits that satisfy the 'additionality' criterion become eligible for trading in the GHG market under the CCX and CDM rules (CCX, 2007c; UNFCCC-CDM, 2007). That is, the GHG reduction achieved with biofuels should be over and above the baseline case or Business-As-Usual (BAU) case. The BAU needs to be defined both in terms of the quality (type of fuel used for baseline) as well as the baseline quantity of biofuel use.

In the case of ethanol, the identification of a baseline fuel becomes tricky due to existing renewable fuel mandates and fuel quality regulations that vary by region or state in the U.S. For example, certain US metropolitan areas afflicted by tropospheric ozone problems have mandated the use of reformulated gasoline (RFG) during summer months, which may contain ethanol (biofuel) or Ethyl tertiary butyl ether (ETBE) or methyl tertiary butyl ether (MTBE) as an oxygenate. Due to a recent ban on MTBE, ethanol is becoming the default fuel additive and oxygenate (EIA, 2003). Similarly areas that do not meet air quality standards for carbon monoxide have mandates to mix ethanol with gasoline to reduce carbon monoxide problems during winter months. Since different types of fuels are used to meet the mandates, any of these fuels—conventional gasoline, RFG with ethanol, or winter gasohol—can serve as the baseline fuel depending on the season and region. The provisions of EISA 2007 mandate renewable fuel use of 7.5 billion US gallons by the year 2012 increasing up to 36 billion gallons by 2022 (Ethanol – GEC, 2005). Various US states also have individual mandates causing variations in the mandated level of biofuels in a region. Further, Federal excise tax incentives ($ 0.54 per US gallon), and additional state tax incentives have resulted in increasing levels of ethanol blending in regular gasoline. Hence, it becomes very difficult to establish what would be a correct BAU baseline quantity for ethanol use (similarly for other biofuels).

Establishing the BAU baseline fuel and baseline quantity is necessary to differentiate the 'project' which generates tradable emission rights from the BAU case and quantify any 'additional' substitution of fossil fuels and the associated GHG emission reductions. The CDM procedures suggest the use of either (general) performance standards or project specific standard baselines, which need to be established on a case-by-case basis for the US biofuels sector (Atkinson, 2006; CCX, 2004).

Who Gets the Property/Trading Rights to Reductions in GHG from Biofuel Use?

The lifecycle emissions analysis of biofuels would include farm level feedstock production, conversion of feedstock into biofuels, storage, transportation, and distribution for blending, and final retail level combustion of biofuels in vehicles. At least four separate economic agents are involved in this process: feedstock growing farmers, ethanol producing plants, fuel blending intermediaries and individual consumers/vehicle owners. The net reduction in GHG is an overall result of their combined actions. This leads to the question of who should get the property rights and thus the trading rights to sell the GHG credits generated through the production and use of biofuels. CCX (2007b) notes that any participant (even feedstock producer or biofuel consumer) can claim the trading rights if ownership rights can be established; there is considerable ambiguity on how these property rights issues would be established unilaterally without regard to the actions of other life cycle participants.

Most of the GHG sequestration occurs during the production of agricultural feedstocks (Lynd and Wang, 2003). But the feedstock is produced by tens of thousands of farmers and their output has multiple potential uses ranging from food, animal feed, industrial raw material, to biofuel feedstock. It is very difficult to identify which specific farmer's, which portion of biomass output was used in biofuel production. This increases the transaction costs of assigning property rights to farmers.

Biofuel consumers can potentially claim the property rights to trade the GHG reductions from biofuel use because it is their ultimate fuel substitution that determines the GHG reduction. However assigning property rights to vehicle drivers is also problematic because there are millions of biofuel users, each of whom is responsible only for a tiny fraction of the GHG benefits, and accounting for and distributing GHG based revenues would almost be impossible. Moreover, both the farmers and consumers are unlikely to have the information about the intermediate steps in the lifecycle process and associated GHG emission benefits.

This leaves either the biofuel producer (e.g. ethanol plants) or the blender as feasible candidates from the perspective of reducing transactions costs and the availability of necessary information, to get the GHG credit trading rights. Traditionally, the US fuel ethanol subsidies have been paid to fuel blenders mainly because the tax credits were simply a function of ethanol blend levels and the blenders chose blend levels depending on the market conditions and local regulations (FHWA, 1998). However, as noted above, the amount of GHG credits generated is a complex function of feedstock composition, fuel sources, input use, and technology adopted in biofuel production, as well as the BAU baseline conditions. The blenders are unlikely to possess this type of information for ethanol that they may blend into gasoline.

Biofuel producers on the other hand are likely to have some of the key information. For example, biofuel producers have knowledge about the feedstock composition and sources, the conversion technology, and hence associated energy use and emissions, and the consumer markets they sell their product in. Hence assigning GHG trading rights to biofuel producers is likely to be feasible and optimal from a transaction costs and information costs perspective. A number of biofuel producers have submitted project proposals seeking trading rights under CDM using similar logic. For example, CDM has approved a methodology for biodiesel (BIOLUX project – AM0047) which "ensures that the CERs[2] can only be issued to the producer of the biodiesel and not to the consumer" (CDM, 2007b). Another project (Khon Kaen fuel ethanol) submitted to the CDM project, seeking the trading rights to be vested with the biofuel producers, notes that

> "A production-based approach to bio-fuel projects greatly assists monitoring. It is not really feasible to monitor individual motorists' actions, but monitoring the production of bio-fuels, and ensuring that only production that is used as a national transportation fuel qualifies for CERs, is an efficient and accurate method of ensuring integrity."
> (Agrinergy, 2004; CDM, 2007c - page 20)

[2] CER – Certified Emission Rights, an equivalent of GHG credits; 1 CER = 1 ton of carbon dioxide equivalent (CO_2e) mitigated

How to Design Verification and Monitoring Mechanisms for Measuring GHG Reductions as Well as Leakages?

The current carbon markets and associated GHG accounting, verification, certification, and monitoring mechanisms vary across countries and by agencies that have separate jurisdiction. However as GHG markets become increasingly global, consistent and comparable methodologies are necessary. The trading methodologies established under CDM for developing countries, under ETS in the EU and (possibly) under CCX in the US have to be consistent so that future global markets are based on common platforms and similar accounting methodologies across national borders and markets (Capoor and Ambrosi, 2007; EU-Environment, 2008; ICAP, 2008; IETA, 2007).

How to Design Incentive Mechanisms that are Compatible with Relative Contribution of Various Participants in the Life Cycle of Biofuels?

The assignment of property and trading rights with biofuel producers may sound optimal from a transaction and information cost perspective, but how the GHG revenues will be shared among the different participants along the value chain is not clear. In a market mechanism, the revenue sharing is based on the relative bargaining power of feedstock producers and consumers vis a vis biofuel producers, i.e., supply and demand elasticities. However the incentive properties of such market-based revenue sharing arrangements are not unambiguous. Alternatively, a governing body (e.g., renewable fuel association) may be designated to develop fiat-based revenue sharing formulae and oversee the distribution among the life-cycle participants, so that the benefits are shared according to their contributions. Even in this case, it would be optimal to retain the trading rights with the biofuel producers. Whether the optimal level of GHG reduction would be achieved under this kind of a trading scheme is an interesting question. Analyzing the tradeoffs and incentive effects on the market participants (quantitatively) is another important issue.

3. Current Global GHG Trading Schemes

Many biofuel projects that reduce GHG emissions have submitted methodologies to the CDM methodologies panel and Executive Board that evaluates and approves the GHG credits, e.g., BIOLUX biodiesel project, Agrinergy ethanol project (Atkinson, 2006; CDM, 2007b, 2007d). One of these project methodologies has been approved and could serve as a template for future biofuel related GHG credit requests (CDM, 2007b). Upon approval of these methodologies, these projects can sell GHG credits—termed as Emissions Reduction Units (ERU) and Certified Emissions Reduction (CER) for GHG credits generated in the developed and developing economies respectively—that are eligible for trading. The demand for GHG credits is generated within the CDM framework by requiring different emitters (e.g. power plants, cement manufacturing facilities) to reduce their GHG emissions levels; currently GHG emitters in EU countries that have ratified the Kyoto Protocol are engaged in trading GHG emission rights. There are private GHG trading exchanges such as GHGx, EUETS, and many over-the-counter (OTC) markets and exchanges serving the EU (EU-Environment, 2007; EUETS, 2007; GHGx, 2007; Point Carbon, 2007; UNFCCC - CDM Bazaar, 2008b). The trading of GHG's usually occurs in a price range of $7 to 15 per metric ton of carbon dioxide equivalent (t_{CO2e}) in organized exchange-based transactions whereas the prices in the OTC markets range from $20-40 per t_{CO2e} (or € 15-30 t_{CO2e}^{-1} at an exchange rate of € 1 = $1.30) (Capoor and Ambrosi, 2007; CCX, 2007a; Point Carbon, 2007).

In the US, since the GHG emissions are not regulated, participation in such markets is voluntary. CCX is one of the private firms that has established a trading platform for GHG trading within the US. The CCX Members commit to reduce their emission level which is legally binding. If they cannot reduce them below committed levels, they can buy offsetting GHG credits (also called carbon credits) from the members who are sellers within CCX; this creates the demand for GHG credits (CCX, 2007d). The GHG credits, called Carbon Financial Instruments® (CFI®), are supplied by offset projects and aggregators who are also members of CCX. These credits are generated in projects within North America, and ratified by CCX for its members through third party verification (CCX, 2007e). The GHG credits are generated by eligible projects such as in forestry, methane digestion, reduced tillage in agriculture, and production of electricity from renewable sources (CCX, 2007b). The projects eligible under CDM methodologies are also eligible under CCX. Since methodologies are being considered to trade the GHG emissions from biofuels in the CDM markets, such biofuel projects can become eligible for GHG credits in the US as well. In spite of their eligibility, there are no approved methodologies to quantify these GHG credits nor is there a GHG trading framework to trade the credits arising from biofuel projects. The next section discusses a possible GHG trading framework that may be appropriate for the US biofuel industry.

4. Proposed GHG Trading Framework for the US

Life Cycle Approach and a Combination of Standards

We propose that the system boundaries include the entire lifecycle and thus the activities of the feedstock producing farmers, manufacturing plants, blending intermediaries and the final consumers. However, quantifying the GHG benefits using LCAs tailored for various biofuel streams and plant locations can be difficult. A streamlined LCA using standard input processes and output (emissions) coefficients can help solve this problem. Such industry averages are known as ‘standardized rules’ in CCX (‘performance standards’ in CDM) and they are extensively used to quantify GHGs eligible for trading (CCX, 2004). However, using industry averages may not be appropriate when the project specific values are available or can be generated with relative ease. For example, information on the specific fuel mix (coal, natural gas) used at an individual ethanol plants is easily available and fuel-mix can significantly affect GHG performance. Hence, we propose a combination of standard and project-specific estimates, i.e., industry or regional level standardized rules for estimating emissions at the farm and final consumer level, and project-specific standards for estimates at biofuel manufacturing plant and blender levels as detailed below.

Feedstock production: We propose using region- and feedstock-specific averages for modeling GHG emissions from feedstock production stage of the lifecycle. This is necessary because there are thousands of farmers that supply multiple feedstocks for biofuel production and accounting for differences in input use and cultivation practices among individual farmers is very difficult.

Biofuel production: Project-specific information associated with feedstock mix (e.g., proportion of corn and cellulose in ethanol production), the technology used for conversion, input fuel mix and other process operations should be available with biofuel producers. Hence we recommend using project-specific data in quantifying the GHG emissions for this stage.

Blending and transportation: Similar to biofuel producers, the blending intermediaries also maintain project-specific data with regard to blend levels (e.g. gasoline-ethanol blends), modes of transportation and the extent of distribution (distance). Since this data is readily available, we recommend using project-specific data for this third stage.

Final use of biofuels in vehicles: Because final consumption of biofuels occurs in millions of vehicles of various makes and models, using a representative mix of vehicle-fleet and 'performance standards' to estimate tail pipe emissions becomes necessary. For an illustration of how to use the emission performance standards to calculate the emissions from a fleet of vehicles, see (CCAR, 2008).

We also recommend using the GREET model as a standard tool in evaluating life cycle performance since it is flexible, and can easily incorporate project-specific details and industry (or geographic) averages as necessary. Moreover, as discussed before, GREET is publicly available, widely accepted, and relatively transparent (ANL, 2007).

Definition of Baseline and Additionality

Defining the baseline, BAU case is crucial in GHG emissions trading to identify and quantify the GHG emission reduction from the 'proposed project activity' (i.e. biofuel substitution). As was discussed above, the definition of a BAU case for biofuel substitution can be tricky due to various types of fuels being used in the BAU case and the presence of multiple mandates that vary by seasons.

To illustrate, there are two types of regulatory requirements for ethanol use in the U.S. The first type is a quality mandate to meet air quality concerns (e.g., mandated reformulated gasoline or gasoline-ethanol blend)—since the ethanol used to meet these mandates would have been used due to regulations, it is not considered to be 'additional;' i.e., the ethanol project might have occurred even without the revenues from GHG credits. The second type of mandate is a quantity mandate. Various states require ethanol to be used in particular proportion to gasoline sold (e.g. 10 per cent of gasoline in Iowa, Kansas, and Hawaii (EPIC, 2008)). Since this ethanol would have been produced and consumed even without the particular project, the project under consideration may not be considered as 'additional.' Hence, the ethanol (or other biofuel) that is eligible for GHG credits should be the quantity that is produced and consumed over and above the mandates (both quantity and quality). For example, consider a case where the total US ethanol output is 20 billion US gallons in the year 2012; if 3 billion gallons were used to meet quality mandates (RFG mandates), and another 15 billion gallons were used to meet various quantity mandates, then only the remaining amount of 2 billion gallons can be considered as 'additional' due to project activities. Here, only 10 per cent of total ethanol production may be eligible for tradable GHG credits, according to this example—hence, the ethanol industry can stake a claim to GHG credits only for 10 per cent of its output during the year 2012. Since the mandates change over the years, the BAU case changes as well and thus the proportion of ethanol eligible for GHG credits needs to be recomputed periodically.

However, ambiguities arise when the quantity mandate also satisfies the quality mandate. In the above example, one can argue that the consumption of 15 billion gallons (under the quantity mandates) includes the 3 billion gallons used to meet the quality mandate as well—hence, the quantity of ethanol eligible for GHG credits is 5 billion gallons, or 25 per cent of the industry output in 2012. Many mandates specify the generic term 'biofuels' rather than one specific fuel (such as ethanol or butanol). If it is not explicitly stated or recognized in mandates, any particular biofuel may become eligible for GHG credits—this means that, in the above illustration, all industry output of 20 billion gallons of ethanol during 2012 may be eligible for GHG credits. Moreover, monetary incentives such as subsidies and tax rebates act indirectly as quantity mandates and the extent to which they affect the net BAU level of biofuel use is difficult to establish.

Given these realities, what proportion of biofuel produced in a particular plant (project) is eligible for GHG credit is not obvious. One option is to use the process described above: the proportion of biofuel output eligible for GHG credits can be calculated based on national mandates, adjusted to reflect the regional or state level mandates. For example, if 70 per cent of the total US ethanol output is required to meet federal mandates, only the remaining 30 per cent would be eligible for GHG credits. This 30 per cent could be uniformly applied to all ethanol plants. If any state requires more ethanol (than the federal mandates) in the form of a mandate, then the ethanol plants in those states alone can be assigned a different baseline level—i.e., if Iowa mandates make 80 per cent of its ethanol output to meet mandates while the federal mandates require only 70 per cent, then the higher of these two should be considered as the baseline (80 per cent in this example).

After establishing the baseline, the project-specific LCA using the GREET model can be used to compute the GHG credits. Table 1 presents selected scenarios where ethanol is produced from corn, using a wet or dry mill production process and used in gasoline or flex fuel vehicles (FFV). The estimates in Table 1 are from version 1.8a of the GREET model under current technology conditions (ANL, 2007). Based on these estimates, if an ethanol plant using corn as the feedstock, and employing dry-mill technology (with US average production techniques and fuel mix) produces 53 million gallons of corn ethanol, and 21 million gallons qualify as 'additional' then the GHG credits generated would be equal to 41.4 thousand tons CO_2e.

Trading Rights with Biofuel Producers

As explained above in section 3, assigning the property rights for trading GHG benefits credits to biofuel producers (e.g. ethanol manufacturing plants) is desirable to minimize transactions and information costs. Most project-specific data in terms of feedstock mix, technology, and energy sources used are available only with the biofuel producers. Table 2 depicts how the actions (energy source used) of the biofuel manufacturing facility affects the lifecycle (well-to-wheel) GHG emission reductions achieved in corn ethanol plants. Other manufacturing plant specific GHG reductions depend on the scale of operations (size) and the combination of feedstock (corn versus cellulosic materials). Further, biofuel manufacturing facilities may not be willing to divulge the specific details to farmers, blenders, or consumers, since much of this information can be of strategic importance in their operations. Hence, assigning the trading rights with any entity other than biofuel producers can lead to the use of incorrect information in the GHG markets. Biofuel producers have project specific information which they might be willing to share confidentially with certifying agencies such as CCX. Biofuel producers then require only

Table 1. Lifecycle GHG emissions per US gallon of ethanol (equivalent) used as automobile fuel

Fuel	GHG[(a)] reduction compared with conventional gasoline (percent)	GHG[(a)] emissions (ethanol equivalent) kg per US gallon	GHG[(a)] emission credit of ethanol kg per US gallon.
	Column A	***Column B*** = 7.61 * (1 – ***Column A***)	***Column C*** = 7.61 – ***Column B***
Conventional gasoline	0	7.61	
Corn ethanol, drymill[(b)] in gasoline vehicles(as E10)	26	5.64	1.97
Corn ethanol, wetmill[(b)] in gasoline vehicles(as E10)	17.8	6.25	1.36
Corn ethanol, drymill[(b)] in FFV (as E85)	29.2	5.37	2.23
Corn ethanol, wetmill[(b)] in FFV (as E85)	21.4	5.98	1.63
Cellulosic ethanol in gasoline vehicles (as E10)	85.1	1.14	6.47
Cellulosic ethanol in FFV (as E85)	85.5	1.10	6.51

Note:
[(a)] GHG refers to greenhouse gases as carbon dioxide equivalent (CO_2e)
[(b)] The terms ‘drymill’ and ‘wetmill’ refer to corn ethanol production processes
FFV refers to Flex Fuel Vehicles that can use gasohol with ethanol content up to 85 per cent
Adapted from Wang (2005)

industry averages (standardized rules or performance standards) for the farmer and consumer activities. If the biofuel producers desire more revenues through selling GHG credits, they have an incentive to source it from the farmers who follow better methods of feedstock cultivation. This indirectly creates a larger demand for feedstock that is produced with lesser GHG emissions. Using standards to quantify the micro emissions is a common practice in GHG accounting and it fits well with the farmers and consumers as prescribed here (CCAR, 2008). The biofuel manufacturing plants are relatively few in number (about 200) and dealing with fewer numbers of producers (who can quantify their project-specific emission levels) is an effective way to address this problem. Assigning the GHG property rights and trading rights to biofuel producers and following the above said framework is also an effective way to account for all biofuel eligible for GHG credits in a cost effective manner.

When the biofuel producers are assigned with the rights, they will be able to “demonstrate clear ownership rights to the environmental attributes associated” as required by CCX (CCX, 2007c, 2004). This can be done in the form of contracts: the contracts between biofuel manufacturing plant and blenders should specify that the ethanol manufacturing plant retains the GHG trading rights. Such a method has precedence in CCX where the forestry offset providers (tree growers) sell only the wooden logs to the timber industry but not the carbon credits associated with growing trees (CCX - Personal Communication).

Table 2: Impacts of different fuel sources on GHG emission reduction

Fuel used in corn ethanol conversion process	Well to Wheel GHG emission reduction of ethanol relative to RFG
Coal	3%
Coal and combined heat and power(CHP)	1%
Natural Gas	-28% to -39%
Distiller grains fueled boiler	-39%
Biomass fueled boiler	-52%

Note: RFG = Reformulated Gasoline; Adapted from Wang et al. (2007)

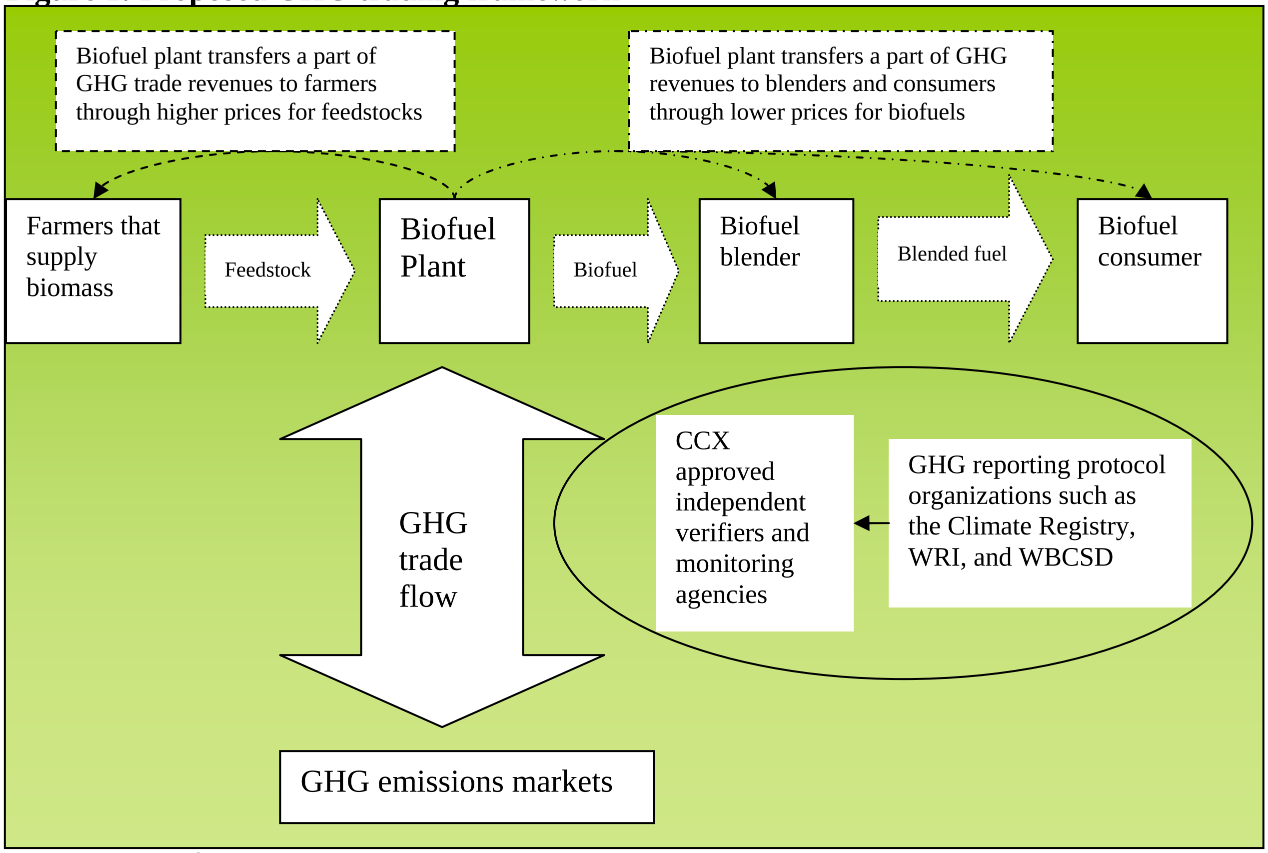
The consumers should understand that they are buying only the fuel properties of biofuel but not the GHG benefits associated with it—their share of revenues from GHG credits for choosing the biofuel over the pure fossil fuel would be passed on in the form of reduced biofuel prices compared with the situation where there are no revenues for GHG revenues. The contracts between feedstock-supplying farmers and ethanol production plants should explicitly state that the GHG reductions achieved from growing the biomass are transferred to the ethanol production plant. This could be contentious since most of the reductions occur at the farm level and the farmers might seek a claim to trade these GHG credits. But assigning the property and trading rights to farmers can lead to extensive leakage of GHG along the supply chain as mentioned below.

The trading framework described above requires approval and diligent acceptance of all the entities: farmers, biofuel industry, the certifying agencies (e.g. CCX), and government. Such coordination is necessary to help avoid the double counting problem (discussed below). The proposed GHG trading framework is depicted in Figure 1. The revenues from GHG trading are available with the biofuel production plants—the extent to which it would be shared with farmers (in the form of higher prices for feedstocks) and consumers (in the form of lower prices for biofuel) would be determined by their relative bargaining power and the demand elasticities for feedstocks and biofuels.

Other Issues

Aggregators: Many smaller biofuel production plants may not have enough GHG credits to trade on their own. These plants could use the services of independent aggregators to bundle the GHG credits of many smaller plants. Or, these plants can form GHG supply cooperatives that can greatly reduce the trading costs for all of them. The industry associations such as National Biodiesel Board or Ethanol RFA can work with the biofuel production plants to establish industry standards (Ethanol-RFA, 2007; NBB, 2007).

Figure 1: Proposed GHG trading framework



Source: Adapted from Kumarappan and Joshi (2008)

Independent verification and ratification: The achievement of GHG reduction through biofuels has to be verified by a third party. It can be done by carbon inventory agencies and registries such as Regional Greenhouse Gas Initiative (RGGI, 2007) or Climate Registry (Climate Registry, 2007; RGGI, 2007). This becomes necessary since there will be many more exchanges that trade in GHG in the US; NYMEX is planning to open one similar to that of CCX (Gardner, 2007). To facilitate easy movement and consistency across exchanges and trading methodologies, the ratification needs to be done by a neutral third party such as RGGI. Their functions would be similar to that of CDM which ratifies the methodologies, tools, and projects in the case of the Kyoto Protocol (Gardner, 2007).

Annual revision: The biofuel plants have to re-calculate the GHG credits that they are eligible to receive since the baseline case can change each year depending on the mandates. This will ensure the incorporation of latest developments and changes in the regulations.

Carbon reserve pools: Due to uncertainties in the estimated levels of GHG reduction, CCX tends to reserve 20 per cent of carbon credits in all the offset projects to create a reserve pool (CCX, 2004). Such rules will be applied for biofuels as well—this will reduce the amount of GHG credits issued to the biofuel producers. The credits in such reserve pools may be used to satisfy the biofuel plants' own 'Emission Reduction Commitments (ERC)' (CCX, 2007d). ERC are the mandatory levels of GHG reduction for CCX members; they can reduce the participation of many biofuel manufacturing plants which are already efficient without much scope for future reductions in their own internal emissions. The lifecycle analysis would partly reduce the burden imposed by ERC for the biofuel manufacturing plants.

Carbon leakage: There are other sources of GHG emissions such as clearing of land to open a biofuel production plant, or the changes in regional land use due to conversion of land from conservation programs to intensive biomass production purposes. These changes could lead to additional GHG emissions which are limited to one time period only. Any other long-term changes such as deforestation to grow biomass feedstock should also be included in the form of non-recurring leakage caused by the project (NEFA, 2008; Winters, 2008). The development and use of lifecycle based GHG emissions trading enables incorporating these types of indirect GHG leakages. In our proposed trading framework, we suggest using regional averages for computing GHG emissions during the feedstock production which will account for any major changes that occur within their feedstock catchment area. This also differentiates biofuels depending on which facility it was manufactured in and what region supplied the feedstock.

Limitations of the Proposed Framework

Our framework has no active mechanism to ensure the appropriate distribution of GHG revenues among all the life cycle participants. This is a common problem in all GHG trading methodologies that include lifecycle assessments but the trading rights are vested with only one agent (the biofuel producers in our case). The success of the proposed model and the reliance on market pricing mechanisms, where the biomass-supplying farmers get higher returns for their feedstock and consumers get biofuel blends at a lesser rate, are predicated upon the optimization behavior of the biofuel producer (Jolly, 2006).

Another issue is associated with Emissions Reduction Commitment (ERC) discussed above. When the biofuel producers are allocated the trading rights, they have more responsibility to reduce their internal emissions according to the rules of CCX. Since their operations require large amounts of fossil fuels, this can reduce their incentives for participating in GHG trading (CCX, 2007d). Under certain conditions, CCX can exempt the offset provider from meeting such ERC obligations; whether these exceptions are applicable in the case of biofuels is yet to be established.

Biofuel production and use also emits many other non-GHG emissions such as nitric oxides, carbon monoxide, particulate matter, and volatile organic compounds (Jacobson, 2007). The health impacts of these non-GHG emissions are not addressed by this study.

5. Implications for US Biofuel Producers and CCX

The revenues from trading GHG credits can be a significant source of revenue for biofuel manufacturing plants. If we assume that one third of the total US ethanol output is eligible for GHG credits (one third of industry output equals 2.2 billion US gallons in 2007), it would have generated \$ 37 million at a carbon price of \$10 per t_{CO2e}. Every billion gallons of 'cellulosic ethanol' eligible for GHG credits can generate \$64 million for the industry at a GHG price of \$10 per t_{CO2e}. The future expansion envisioned in the fuel ethanol industry in the US can bring revenues of up to $525 million as shown in Table 3. The actual revenues for an individual ethanol plant would however depend on the industry output, mandates, biomass feedstock used, production and energy input mix, storage, blend levels, transport, and the mix of automobiles that consume biofuels.

Table 3: Potential revenues from every one billion gallons of ethanol eligible for GHG credits (in dollars)

	GHG Price		
	$3 per Mg	**$10 per Mg**	**$20 per Mg**
Corn Ethanol 50% Cellulosic Ethanol 50%	$ 12 million	$ 41 million	$ 82 million
Corn Ethanol 80% Cellulosic ethanol 20%	$ 8 million	$ 26 million	$ 53 million
Corn Ethanol 100%	$ 5 million	$ 17 million	$ 34 million

Source: Adapted from Kumarappan and Joshi (2008) and Wang (2005)

Adopting such a trading framework and allowing the biofuel producers to trade the GHG credits have implications for CCX as well. Ethanol use in transportation alone can generate carbon credits of 1.7 and 6.4 million tons of GHG credit for one billion gallons of corn ethanol and cellulosic ethanol, respectively. With 5 to 7 billion gallons of ethanol (or other biofuels) eligible for GHG credits, over and above the quantity and quality mandates by the year 2022, the supply of GHG credits can range from 8 to 40 million tons. In the past 12 months (starting December 2007), CCX traded around 69 million tons of GHG credits. With a mandate to curb GHG emissions, the demand can increase considerably by the year 2022 and the above-mentioned GHG credits from biofuels might form a significant portion of supply in the GHG markets. Such a considerable increase in the supply of GHG credits from the biofuels sector can depress GHG prices in the US, if no other governmental regulations such as carbon caps can create a compensating demand for these credits. Hence, the proposed GHG trading framework has potentially large implications for the US GHG markets as well.

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