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Administrator Lisa Jackson
Ariel Rios Building
1200 Pennsylvania Avenue, N.W.
Mail Code: 1101A
U.S. Environmental Protection Agency
Washington, DC 20460

Subject: Comments on EPA's proposed changes to the Renewable Fuel Standard rules
Docket EPA-HQ-OAR-2005-0161

Dear Administrator Jackson:

NPRA, the National Petrochemical and Refiners Association, is pleased to provide comments on the Agency's proposed changes to the Renewable Fuel Standard (RFS2) rules (74 FR 24904; 5/26/09). NPRA's members comprise more than 450 companies, including virtually all U.S. refiners and petrochemical manufacturers. Our members supply consumers with a wide variety of products and services that are used daily in homes and businesses. These products include gasoline, diesel fuel, home heating oil, jet fuel, asphalt products, and the chemicals that serve as "building blocks" in making plastics, clothing, medicine and computers.

NPRA recognizes the need for a workable and flexible RFS2 rule with a reasonable transition from the RFS1 rules. Our members have spent the last two years implementing the RFS1 rules and we appreciate the regulatory complexities inherent in the Energy Independence and Security Act of 2007's RFS2 provisions. The RFS2 rules in 40 CFR Part 80 will have significant consequences for many stakeholders.

NPRA appreciates the Agency's outreach efforts regarding this rulemaking. EPA has made every effort to solicit appropriate stakeholder input on key matters. We anticipate that these early discussions and the ensuing open and transparent rulemaking process will lead to an effective final rule and potentially avoid unintended consequences.

NPRA members are very interested in the potential of the RFS2 RIN EPA Moderated Transaction System (EMTS). We commend your foresight. This new system could eliminate many errors and problems with RFS RIN processing.

The RFS2 program should begin on January 1, 2011; January 1, 2010 implementation is infeasible.

As regards EPA's lifecycle analysis for RFS2, NPRA commends the Agency for its scientific approach and diligence in examining the full gamut of potential impacts from the production and use of various biofuels. NPRA agrees with EPA's interpretation that the Clean Air Act requires that EPA consider both direct and indirect land use change impacts.

If the RFS2 regulations will be effective on January 1, 2011, then statutory mandates for biomass-based diesel for 2009 and 2010 and for cellulosic biofuel for 2010 should be ignored or eliminated. If the RFS2 regulations will be effective on January 1, 2010, then the statutory mandate for biomass-based diesel for 2009 and cellulosic biofuel for 2010 should be ignored or eliminated. The Agency has no authority to "recapture" volume mandates under different start-date scenarios.

The RFS2 obligated party should be the provider of finished transportation fuels. It is the party that has title to the gasoline and diesel at the truck rack that controls what if any renewable fuel is blended. Making the blender who is responsible for turning RBOB and CBOB into finished fuels the obligated party, whether the RBOB or CBOB is at or below the rack, will go a long way in leveling the playing field among all parties. The current designation of refiners and importers as obligated parties is no longer a workable option given the changes in the RFS2 requirements versus the RFS1 requirements. In addition, the current regulations have already had unintended consequences.

NPRA urges EPA to reject Growth Energy's petition to increase the allowable ethanol content of gasoline to 15 percent for the following reasons: (1) the science on the impact of mid-level ethanol blends on consumer safety, engine performance, and potential environmental harm has not been completed and likely will not be completed for at least two years; (2) the information submitted by Growth Energy in support of its petition is a woefully inadequate foundation upon which to base such an important change in the nation's supply of gasoline; (3) the potential approval of Growth Energy's petition is not an effective short- or medium-term solution to avoiding the "blendwall" problem caused by the increasing conventional biofuels volumes mandated under EISA and thus EPA should not rush such an important decision until a scientifically-based rationale can be reached regarding consumer safety, engine reliability, and environmental concerns of mid-level ethanol blends use in all gasoline-powered motor vehicles and engines in use in the United States; and, (4) this seemingly modest petition will, if granted, have wide-ranging implications on other federal and state fuels programs and will require a series of complex and lengthy rulemakings to harmonize these programs with the introduction of mid-level ethanol blends.

In addition, NPRA also opposes the grant of a "partial waiver" to permit the use of mid-level ethanol blends in some gasoline-powered engines for the following reasons: (1) it would cause significant disruption in the nation's wholesale and retail gasoline distribution infrastructure, widespread consumer confusion and potential misfueling, and potential liability for engine and fuel manufacturers for any damage caused to gasoline-powered engines not compatible with mid-level ethanol blends; and, (2) EPA does not have the statutory authority under Section 211(f) of the Clean Air Act to grant a partial waiver.

NPRA supports the prudent development and use of biofuels, including ethanol, to diversify our nation's transportation and nonroad fuels portfolio. However, before the use of mid-level ethanol blends is permitted, EPA has an affirmative obligation to find, based on comprehensive and unbiased test data, that these blends are safe for consumers, do not harm gasoline-powered engines, and do not lead to increases in emissions from these engines that will harm the environment. The data submitted by Growth Energy in its petition does not come close to meeting these admittedly and necessarily high standards, and thus the petition must be rejected.

Additional discussion of these issues and many other topics is available in the attachments.

Sincerely,

Charles T. Drevna
President

Attachments

cc: Gina McCarthy
Margo Oge
Chet France
Paul Machiele
Docket EPA-HQ-OAR-2005-0161

COMMENTS OF

THE NATIONAL PETROCHEMICAL

& REFINERS ASSOCIATION

ON EPA'S PROPOSED CHANGES TO THE

RENEWABLE FUEL STANDARD RULES

(74 FR 24904; 5/26/09)

Docket ID No. EPA-HQ-OAR-2005-0161

A. INTRODUCTION

NPRA recognizes the need for a workable and flexible RFS2 rule with a reasonable transition from the RFS1 rules. Our members have spent the last two years implementing the RFS1 rules and we appreciate the regulatory complexities inherent in EISA's RFS2 provisions. The RFS2 rules in 40 CFR Part 80 will have significant consequences for many stakeholders.

NPRA appreciates the Agency's outreach efforts regarding this rulemaking. EPA has made every effort to solicit appropriate stakeholder input on key matters. We anticipate that these early discussions and the ensuing open and transparent rulemaking process will lead to an effective final rule and potentially avoid unintended consequences.

NPRA members are very interested in the potential of the RFS2 RIN EPA Moderated Transaction System (EMTS). We commend your foresight. This new system could eliminate many errors and problems with RFS RIN processing.

After a brief RFS2 background discussion, NPRA's comments address:

- Renewable Volume Obligation,
- Lifecycle GHG Emissions Analysis,
- Renewable Identification Numbers,
- Mid-level Ethanol Blends and E-15 Considerations,
- Other,
- Technical Corrections, and
- Appendices.

B. BACKGROUND

President Bush signed the Energy Independence and Security Act of 2007 (EISA, Public Law 110-140) on December 19, 2007. Among many provisions, this energy bill increased the Renewable Fuel Standard (RFS) beginning in 2008, increasing to 36 billion gallons in 2022, and established a subset of the RFS labeled Advanced Biofuel beginning in 2009. Implementation of the numerous revised RFS provisions in Subtitle A of Title II of EISA is the subject of this rulemaking.

The revised RFS (referred to here as RFS2) will convert the statutory RFS volumes to a percentage of transportation fuels (gasoline and highway/nonroad diesel[1]). Currently, RFS1 (as established by the Energy Policy Act of 2005, EPAct05; see RFS1 regulations at 72 FR 23900; 5/1/07)[2] is regulated as a percentage of gasoline only. In addition, RFS2 expands the scope to include renewable fuel used to replace or reduce the quantity of fossil fuel in home heating oil or jet fuel.[3]

EISA also created a complicated mix of submandates for specific classes of renewable fuels:

- Conventional Biofuels – Under the RFS2, there is no direct submandate for conventional biofuels, which is defined in EISA as ethanol derived from corn starch. However, there is an implicit corn ethanol mandate under the RFS2 which rises from 10.5 billion gallons in 2009 to 15 billion gallons in 2015.[4] In addition, under the RFS2, conventional biofuels must reduce direct and indirect lifecycle greenhouse gas ("GHG") emissions at least 20 percent from the 2005 transportation fuel baseline if the renewable fuel manufacturing facility commences construction after the date of enactment (the "grandfather" provision).

- Advanced Biofuels – Under the RFS2, "advanced biofuels" exclude biofuels derived from corn starch and must reduce direct and indirect lifecycle GHG emissions by at least 50 percent from the 2005 transportation fuel baseline. The advanced biofuels mandate has three submandates: cellulosic biofuel; biomass-based diesel; and "other."

  - *Cellulosic biofuels* requirements are a subset of the advanced biofuels submandate and must reduce direct and indirect lifecycle GHG emissions by at least 60 percent from the 2005 transportation fuel baseline.

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1 Including nonroad vehicles and engines except for ocean-going vessels.
2 RFS1 regulations were modified at 73 FR 57248 (10/2/08), 73 FR 71560 (11/25/08), 73 FR 71940 (11/26/08), and 74 FR 29948 (6/24/09).
3 EPAct05 restricted 'renewable fuel' to replace or reduce the quantity of fossil fuel used to operate a motor vehicle. See CAA section 211(o)(1)(C)(i).
4 The difference between the statutory mandates for the general total RFS and Advanced Biofuels.

Cellulosic biofuels must be derived from any cellulose, hemicellulose, or lignin from renewable biomass.[5]

- *Biomass-based diesel* is another subset of advanced biofuels and must reduce direct and indirect lifecycle GHG emissions by at least 50 percent from the 2005 transportation fuel baseline. Biomass-based diesel is defined under section 312(f) of the Energy Policy Act of 1992.[6] The regulatory values for biomass-based diesel after 2012 will be determined by EPA, in consultation with DOE and USDA, and promulgated no later than 14 months before the first year for which the new volume applies.
- "Other" advanced biofuels has regulatory significance because the statutory sum of cellulosic biofuels and biomass-based diesel is less than the total volume requirement of advanced biofuels. The "other" advanced biofuels subset can be met with ethanol derived from sugar or additional cellulosic biofuels or biomass-based diesel.

The table on the next page shows the nested nature and statutory minimum annual volumes of these new RFS2 requirements.

[5] Renewable biomass is restricted to exclude planted crops and crop residue from agricultural land cleared after December 19, 2007, and planted trees and tree residue from federal land.

[6] Section 312(f): "For the purpose of this section - -

(1) the term 'biodiesel' means a diesel fuel substitute produced from nonpetroleum renewable resources that meets the registration requirements for fuels and fuel additives established by the Environmental Protection Agency under section 7545 of this title [Section 211 of the Clean Air Act, Regulation of Fuels];"

RFS2
(billion gallons)

	Biomass-based Diesel	Cellulosic Biofuel	Total Advanced Biofuel	Total Renewable Fuel
2007				4.70
2008				9.00
2009	0.50		0.60	11.10
2010	0.65	0.10	0.95	12.95
2011	0.80	0.25	1.35	13.95
2012	1.00	0.50	2.00	15.20
2013	[a]	1.00	2.75	16.55
2014	[a]	1.75	3.75	18.15
2015	[a]	3.00	5.50	20.50
2016	[a]	4.25	7.25	22.25
2017	[a]	5.50	9.00	24.00
2018	[a]	7.00	11.00	26.00
2019	[a]	8.50	13.00	28.00
2020	[a]	10.50	15.00	30.00
2021	[a]	13.50	18.00	33.00
2022	[a]	16.00	21.00	36.00

Source: the Energy Independence and Security Act of 2007, section 202

[a] To be determined by EPA, in consultation with DOE and USDA, and promulgated no later than 14 months before the first year for which the new volume applies.

The requirements for at least 9.0 billion gallons in 2008 and 11.1 billion gallons in 2009 were promulgated by the Agency and did not require final RFS2 regulations.[7] Refiners and gasoline importers complied with the 9.0 billion gallons and are complying with the 11.1 billion gallons requirements using the RFS1 regulatory framework.

C. RENEWABLE VOLUME OBLIGATION (RVO)

1. The RFS2 program should begin on January 1, 2011. January 1, 2010 implementation is infeasible.

EPA should provide the affected industries adequate lead time to implement these complicated new rules. There simply is not time between now and January 1, 2010 to implement these rules.

There is not sufficient time before January 1, 2010, for EPA to adequately review and respond to comments submitted by September 25, 2009, make decisions on the options under consideration, and allow for the required Congressional review period. In addition, depending on how the Agency decides to promulgate the RFS2 requirements, foreign and domestic renewable fuel producers may have insufficient time to satisfy the requirements for registration under proposed section 80.1450. Under this provision, producers are required to provide EPA a list of feedstocks capable of being used by each facility, a description of the facility's renewable fuel production capacity, a list of the facility's process energy sources, and an independent third party engineering review and written verification of the information. This will likely take renewable fuel producers significant time to implement.

In addition, considerable time will be required for the renewable fuel producers to put in place systems to ensure that the feedstocks used in making their products meet the definition of "renewable biomass." Under proposed section 80.1426, RINs must be generated for any fuel that meets the definition of "renewable fuel" and may not be generated for fuels that do not meet the definition of "renewable fuel." Thus for each batch of fuel produced, the producer must determine whether the fuel meets the definition of "renewable fuel." To do so requires the producer to determine whether the feedstocks for the fuel meet the definition of "renewable biomass." This in turn will require most renewable fuel producers to determine whether the feedstock was grown on land that meets the definition of "existing agricultural land." See 80.1426(d) and 80.1401. It will take the renewable fuel producers substantial time and effort to make these determinations. It will also take time to put in place the processes necessary to ensure that the fuels that are produced continue to meet these requirements, and the processes to ensure that adequate records are generated and maintained to meet the recordkeeping requirements under sections 89.1451(b) (e.g., "records that serve as evidence that the land from which the feedstock was obtained was continuously and actively managed or fallow, and nonforested, since December 19, 2007."). It is simply

[7] See 73 FR 8665 (2/14/08) and 73 FR 70643 (11/21/08).

not possible to comply with these registration requirements and put in place the necessary processes between now and January 1, 2010.

EPA should provide the industry adequate time to put in place systems to track the four (or more) different kinds of RINs that will have to be accounted for under this rule. Indeed, at this point, the obligated parties do not even know for certain whether they will have to account for only four types of RINs or six given the uncertainty that surrounds the ability of most vegetable oil sourced diesel fuels to meet EISA's greenhouse gas emission reduction requirements for biomass-based diesel.

There is not sufficient time to implement the biomass-based diesel program between now and January 1, 2010 given that it is unclear whether most vegetable oil based fuels will meet EISA's greenhouse gas emission reduction requirements. EPA discusses several ways that the Agency might deal with this problem, but at this time, the obligated parties have no certainty and therefore no ability to put in place plans to attempt to comply with the biomass-based diesel requirement. EPA needs to provide this certainty, and then provide the industry time to put in place plans for compliance.

It is not even clear at this time whether refiners and importers will be the obligated parties, or whether the obligation will be shifted downstream to parties who are better able to make decisions concerning how much, and which, renewable fuels to blend. EPA needs to provide certainty to the regulated community on this critical issue, and time sufficient for the obligated parties to put into place plans for compliance.

Although EPA has proposed not to waive the cellulosic renewable fuel requirement for 2010, EPA has not adequately evaluated whether there will in fact be 100 million gallons of production of cellulosic ethanol in 2010. NPRA is doubtful that there is in fact 100 million gallons of existing production capacity. EPA should do a thorough analysis of the availability of cellulosic ethanol and adjust the cellulosic, advanced, and total renewable standards if there is not sufficient existing production capacity to meet the cellulosic mandate. Until this analysis is done, the obligated parties do not have certainty regarding the actual size of the obligation. EPA needs to provide the obligated parties this certainty, and sufficient time to put into place plans for compliance.

In sum, at this point, the only workable option for implementation of the program is January 1, 2011 or later. Even if EPA is able to promulgate a final rule before January 2010, it will take until 2011 to accomplish the registrations that are required and to put in place the systems and plans that are necessary for compliance (assuming that EPA can issue the final rule by January 2010). EPA should not attempt to implement the program in mid-2010. A mid-2010 start date will not provide the regulated parties sufficient time to accomplish the registrations and put plans in place for compliance. Moreover, starting the program in mid-2010 will only add additional complexities (e.g., additional RIN types to distinguish RFS1 RINs from RFS2 RINs) and will make a smooth transition to the RFS2 rules impossible.

2. **If the RFS2 regulations will be effective on 1/1/11, then statutory mandates for biomass-based diesel for 2009 and 2010 and for cellulosic biofuel for 2010 should be ignored/eliminated. If the RFS2 regulations will be effective on 1/1/10, then the statutory mandate for biomass-based diesel for 2009 and cellulosic biofuel for 2010 should be ignored/eliminated.**

Under Clean Air Act section 211(o)(3)(B)(i), as amended by the Energy Policy Act of 2005, the EPA Administrator is obligated to "publish in the Federal Register, with respect to the following calendar year, the renewable fuel obligation that ensures that the requirements of paragraph (2) [renewable fuel volumes] are met." On November 21, 2008, EPA published in the Federal Register the required notice pertaining to the year 2009 (73 FR 70643), titled "Renewable Fuel Standard for 2009, Issued Pursuant to Section 211(o) of the Clean Air Act".

In the November 21, 2008 notice, EPA asserted that without a final RFS2 rulemaking that would implement the changes to RFS1 made by EISA, EISA's provisions could not be enforced. In particular, EPA noted that "the RFS1 regulatory structure does not provide a mechanism for implementing the EISA requirement for use of 0.5 billion gallons of biomass-based diesel."

The notice went on to say that in the upcoming RFS2 rulemaking, the Agency intended to propose that the 2009 biomass-based diesel requirement be lumped together with the 2010 requirement. Obligated parties would demonstrate compliance with the combined requirement at the end of 2010.

The RFS2 Notice of Proposed Rulemaking did, as promised, propose a combined 2009/2010 standard of 1.15 billion gallons (bg).[8] However, further delay in promulgating the RFS2 rulemaking since the November 21, 2008 notice has given rise to doubts that the final rule can be made effective before 2011. Logically, EPA might consider lumping *three* years of EISA requirement together, for a total of 1.95 bg, for the 2011 compliance year. NPRA believes this would be taking a questionable idea to the point of absurdity. 1.95 bg is nearly twice the requirement for the following and subsequent years, 2012 onward. Current production is now at a small fraction of the proposed 2009/2010 requirement, let alone one that lumps three years together. Public reports indicate that many biodiesel plants have shut down. The biodiesel industry would have to ramp up very quickly to supply the needed volumes (albeit lower than the combined requirement due to RIN carryover — see next section) in the face of a lower sustained requirement, an unlikely outcome for businesses generally acknowledged to be in financial straits.

EPA should not combine the 2009 and 2010 requirements. By imposing the 2009 volume requirements in 2010, EPA would be imposing a retroactive requirement and immediately put obligated parties in a compliance deficit.

[8] See 74 FR 24957.

EPA should abandon any notion that EISA requirements can be brought forward. Should EPA define the RFS2 start date as 1/1/2011 as recommended by NPRA, the 2011 EISA biomass-based diesel requirement of 0.80 bg would be a substantial fraction of the proposed 2009/2010 lumped requirement of 1.15 bg, which NPRA believes will be a significant challenge to meet without the addition of a retroactive requirement. This 2011 requirement would come at a time when production is even lower than when EPA issued its November 21, 2008 notice.

EPA does not have the authority to combine standards for the cellulosic biofuel mandate.

In addition, EPA should not attempt to combine the 2010 and 2011 yearly standards for biomass-based diesel or cellulosic renewable fuels.

Biomass-based diesel: Imposing a combined multi-year standard is contrary to the plain language of EISA. By proposing to combine the 2009 and 2010 biomass-based diesel standards, EPA is effectively escalating the standard above 1 billion gallons in advance of the schedule that Congress established, and without considering the factors that Congress specified. The law expressly provides that the volume requirements for the years 2009 through 2012 “shall” be determined in accordance with the table in the law, which specifies that the volume mandate in 2010 is 0.65 billion gallons, not 1.15 billion gallons as EPA proposes. Moreover, the law specifies that EPA can only adjust the volumes for years “after the calendar years specified in the table” and only after the factors specified in the law are taken into account. EPA’s proposal to combine the 2009 and 2010 volume mandates for 2010 is clearly contrary to the express intent of Congress. Combining the 2009 and 2010 standards also makes little sense as a practical matter since it results in a standard of 1.15 billion gallons when Congress only envisioned a 1 billion gallon mandate in 2012. Thus, by combining the 2009 and 2010 standards, EPA is creating a situation where unnecessary blending capacity is required for a one year period. The same would be true if EPA attempts to combine the 2010 and 2011 standards if the RFS2 program starts in 2011.

Cellulosic biofuel: Just as it would exceed EPA’s authority to combine yearly standards for biomass-based diesel, it would exceed EPA’s authority to combine standards for the cellulosic biofuel mandate. The law sets out the schedule for the cellulosic biofuel volume mandate and the conditions under which EPA can change the volume mandate. In particular, the law states that the “applicable volume of cellulosic biofuel for the calendar years 2010 through 2022 shall be determined in accordance with the following table:” which specifies that the applicable volume in 2011 is 0.25 billion gallons. In addition, the same provision that sets forth the conditions on the Administrator’s ability to increase the volume mandate for biomass-based diesel also applies to cellulosic biofuel and is clear that it applies for “calendar years after the calendar years specified in the table.”

EPA cannot impose, on a retroactive basis, biomass-based diesel requirements for 2009 or any other period that precedes a final rulemaking for RFS2 that includes provisions sufficient to implement EISA requirements. The Agency has no authority to “recapture” volume mandates under different start-date scenarios.

NPRA

NPRA strongly opposes any attempt by EPA to impose retroactive regulatory requirements related to biomass-based diesel. EPA indicates in its Preamble to the RFS2 Proposed Rulemaking that since the Agency in the RFS1 rulemaking interpreted section 211(o)(5)(C) of the CAA to allow parties to carry a deficit in credits of any size from one year to the next, this same statutory authority provision also allows the Agency to propose that the compliance demonstration for 2009 biomass-based diesel be extended into 2010. The Agency then indicates that it is a "reasonable exercise of its authority under section 211(o)(2) to issue regulations to ensure that the volumes for 2009 are ultimately used even though we are unable to issue regulations prior to the 2009 compliance year."[9]

There is not a current obligation in 2009, established through regulation, for obligated parties to use biomass-based diesel in order to meet the statutory requirements of EISA. The 2009 biomass-based diesel requirement is not self-executing but requires the revision of regulations as the Agency itself indicates by referencing its reliance on the authority contained in CAA section 211(o)(2). EISA provides that increased annual levels of the 211(o) renewable fuel obligation and the relevant categories of fuels are to be established through regulation promulgated pursuant to section 211(o)(2). Therefore, an obligated party can incur no obligation to comply with the biomass-based diesel requirement before the effective date of the RFS2 regulation.

Imposing a requirement for utilization of biomass-based diesel for the entirety of 2009 when final rules implementing the definition of this fuel have not been promulgated is arbitrary and capricious. The relevant statutory definition for this fuel contains requirements that it be made from renewable biomass, its lifecycle GHG emissions must be at least 50% less than the 2005 diesel baseline, and excludes co-processed biomass/petroleum feedstock fuel from qualifying as biomass-based diesel. None of these regulatory definitions have been promulgated, nor are RINs available for acquisition which are based on a regulatory definition, making it impossible for an obligated party to comply with the RFS2 requirements during the current year or any other period since the enactment of EISA. While the Agency acknowledges this is a problem,[10] the Agency does not posit a legally defensible solution. Instead, EPA merely states its belief that biodiesel produced in 2009 "should" meet the minimum 50% lifecycle GHG emissions reduction threshold even though all elements of the current lifecycle analysis requirements have not been finalized and the Agency has not responded to comments on its proposed methodology to establish such analysis.

EPA's additional rationale that because a source may defer obligations from one year to the next, the Agency can, by extrapolation, impose regulations in a retroactive fashion has no statutory basis and fails on the face of its logic. CAA section 211(o)(5)(C) indicates that

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9 74 Fed. Reg. at 24957 (May 26, 2009).

10 The Preamble states that "there is no practical way to determine after the fact if RINs generated in 2009 meet any of the [GHG threshold] criteria . . ." and that "at least some renewable fuels produced in 2009 would not meet these thresholds." (74 Fed. Reg. at 24962). These statements are tantamount to an admission by EPA that it is impossible to comply with the relevant requirements prior to the establishment of final rules.

credits generated under the RFS program are valid to show compliance for 12 months after generation. Under the statute, obligated parties (e.g., refiners, blenders and importers) are those who are required to "show compliance" with the applicable volume. Simply because the statute extends this compliance flexibility to an obligated party, letting such a party use credits for 12 months after generation, does not extend a similar implementation flexibility to the Administrator to require an obligated party to "show compliance" for a period of time before final regulations were legally effective. Instead, the provision acts to limit the Administrator's ability to require an obligated party to show compliance with an annual volume requirement (e.g., by preventing the Administrator from requiring that only those actions an obligated party takes to generate or acquire credits within the previous calendar year could be used show compliance for that year).

With respect to CAA section 211(o)(2), reasonable interpretation of this section simply cannot support shifting the statutory schedules from one year to the next. The EPA seeks to effectively read only part of the relevant statutory authority indicating that because it is to "ensure" that applicable volumes are met, this means that it can reach back in time to require obligated parties to address obligations that have already passed. Instead, section 211(o)(2) clearly indicates that the Administrator is to "ensure" that the applicable volume is to be met with reference to the calendar year in which the requirement is imposed (such levels are to be "determined in accordance with subparagraph B"). Subparagraph B clearly indicates that for the purpose of subparagraph A, the applicable volume shall be determined "in accordance with the following table" which contains volumes by year. Such a statutory structure, indicating precise calendar years and precise volumes of renewable fuel (of which biomass-based diesel is a subpart) effectively cordons off the Administrator's discretion. EPA simply does not have the statutory ability to determine that required volumes somehow "trump" the specific statutory schedule with regard to the years in which such volumes are specified. Neither can the Agency simply shift volume requirements in time when the timing of specific volumes is clearly specified.

With respect to CAA section 211(o)(5)(C), as explained earlier, this statutory flexibility for obligated parties cannot be converted into new statutory authority for the EPA. Summing separate year-to-year volume requirements effectively imposes a new requirement on obligated parties not specified in statute. Relying on the legal ability of a party to comply over time, as provided in section 211(o)(5)(C), to provide authority to EPA to impose wholly new obligations is counterintuitive and cannot be supported by the plain reading of the statute.

Taking EPA's statutory theories to their logical conclusion serves to demonstrate their inherent flaws. According to the statutory theory the Agency posits, if a RFS2 regulation is not final until after January 1, 2011, EPA would lack the statutory authority to require compliance with the 2009 biomass-based diesel requirement. This is because EPA believes it could not require compliance for three years (2009, 2010, and 2011) based on its interpretation of a one-year ability to carry over obligations and a two year lifespan for credits.[11] However, this appears to be the only limit on the discretion that the Agency

[11] 74 Fed. Reg. at 24959.

affirmatively states in the Preamble with regard to its purported ability to interpret CAA sections 211(o)(2) and 211(o)(5)(C). The Agency does not indicate, in the affirmative, that it could not implement volume requirements for 2010 in a regulation which is finalized after January 1, 2011 or specify at what point in 2011 the Agency could not implement volume requirements for 2010. Instead, under the statutory theory presented, the Agency could presumably finalize a regulation at any time prior to December 31, 2011 and believe it had the authority to retroactively impose obligations on parties to comply with such standards for the entirety of 2010 and 2011. Again, such a result is precluded by the statutory schedules in section 211(o)(2).

The Preamble is similarly unclear as to what course the Agency may pursue with respect to a final regulation that occurs after January 1, 2010. While the Agency indicates it may be considering applying such a regulation only to RFS volumes produced in 2010 or after the effective 2010 date of a regulation, it implies it has authority to determine an "appropriate" level of the standard.

NPRA strongly objects to a statutory interpretation which would, even in theory, allow such unbounded discretion. EPA does not have unbounded discretion to determine an "appropriate" level of the standard to apply in a final regulation promulgated after January 1, 2010. Such a term does not appear anywhere within CAA section 211(o)(2)(A) or (B), the relevant statutory authorities for determining the applicable volume of renewable fuel. Similarly, EPA has no authority to "recapture" volume mandates under different start-date scenarios. The statute clearly imposes volume requirements with respect to specific years and contains no authority for the Agency to reach back with unbounded discretion. Instead, as the Agency implemented in the RFS1 rulemaking based on the same legislative language it interprets in the RFS2 Proposal for Rulemaking, any volume requirements must apply only prospectively.

<u>Implications of EPA's proposal</u>

In the November 21, 2008 notice, EPA very clearly advised obligated parties to prepare for the 2010 combined biomass-based diesel requirement by stating:

> While obligated parties would not need to demonstrate compliance with the combined 2009/2010 biomass-based diesel standard until the end of the 2010 compliance period under this approach, *it would behoove them to acquire the necessary RINs representing biodiesel and renewable diesel in 2009* in preparation for their 2010 compliance demonstration. [emphasis added]

73 FR 70643.

EPA backed this advice to obligated parties with a thinly veiled threat of enforcement action should they not follow that advice:

> Obligated parties that delayed their efforts to acquire these RINs until 2010 could find that they would be unable to acquire a sufficient number for compliance purposes.

On May 26, 2009, EPA did indeed propose such a mechanism to address the 2009 biomass-based diesel requirement in the RFS2 proposed rule, "Regulation of Fuels and Fuel Additives: Changes to Renewable Fuel Standard Program" (74 FR 24904). In that notice, EPA reiterated the need for obligated parties to acquire sufficient RINs in 2009 to satisfy the combined requirement:

> Moreover, it [the use of prior-year RINs for compliance] allows an obligated party to acquire sufficient biodiesel and renewable diesel RINs during 2009 to comply with the 0.5 billion gallons requirement, even though their compliance demonstration would not occur until the 2010 compliance period.

Because of continued delay in the issuance of the proposed RFS2 implementation rules, EPA has asked for comment on start dates as late as January 1, 2011. Start dates later than the proposed January 1, 2010 cast doubt on the ability of the agency to enforce the biomass-based diesel volumes retroactively as the yearly volumes pile up on one another. The deficit carry-over provisions and RIN life provisions that the agency relies on to justify the combined standard don't appear to support carryover of 2009 biomass-based diesel RINs (those with RR codes of 15 or 17) beyond the 2010 compliance period. Therefore, companies that relied on EPA's advice to acquire biomass-based diesel RINs in 2009 have cause to be concerned that investments in such RINs will be lost. If the start is delayed yet further, RINs acquired in 2010 may also be at risk.

To be fair to companies that relied on EPA's strongly-worded advice and to maintain the regulated industry's confidence in EPA's written word, the Agency needs to preserve the ability to use prior-year diesel RINs for biomass-based diesel compliance regardless of how and when the program finally rolls out. To do otherwise is to strand capital or operating expense. Companies that followed the Agency's advice should not be punished for acting in good faith. Also at risk is EPA's often-used contention that regulated parties know what is coming and so have time to prepare for compliance in excess of what is provided between final Agency action and effective date. If EPA's *written* advice in this case cannot be relied upon, regulated parties cannot possibly be expected to do any compliance planning until final action is complete.

We understand that EPA's rationale for establishing the proposed 2009/2010 biomass-based diesel standard is in jeopardy should the start date be extended, but in extending the start date EPA will have to establish a transition program to manage other EISA mandates as well as addressing a few practical matters that are seriously compromised by the delay in promulgating the final rules. As part of this transition program, EPA should explicitly allow the use of prior-year diesel RINs procured based on EPA advice for biomass-based diesel compliance with the first biomass-based diesel volume mandate established under the final RFS2 rules.

EPA should not have advised obligated parties to prepare for the 2010 combined biomass-based diesel requirement. The 2010 combined biomass-based diesel requirement was only a proposal, not a final rule. In fact, the proposed 2010 combined biomass-based diesel requirement would be an unfair retroactive regulation. The Agency should not be advising stakeholders on compliance with a proposed and unfair retroactive regulation. However, given that EPA has already done this, the Agency should accommodate the use of these RFS1 biodiesel RINs in the RFS2 regulatory compliance program.

3. The RFS2 obligated party should be the provider of transportation fuels.

In section III.G.4 of the preamble (74 FR 24963), EPA proposes two alternative approaches to the designation of obligated parties. The first alternative is to remove RBOB and CBOB from the list of fuels that are subject to the standard and to make parties that blend ethanol into RBOB and CBOB (ethanol blenders) obligated parties. The second alternative is to move the obligations for all gasoline and diesel downstream to parties who supply finished transportation fuels. NPRA supports the second approach.

There are numerous problems with the current RFS1 regulations that will be magnified under the RFS2 regulations if the obligated party remains the refiner/importer. The current form of the regulation does not: maximize benefits and minimize costs, treat all regulated parties equally, or minimize costs to the consumer. It is not workable and is causing unintended consequences. Specifically the current definition of obligated party has the following issues:

1. Creates an uneven playing field among refiners/importers
2. Creates an uneven playing field between refiners and renewable fuel blenders
3. Does not address issue of state clear gasoline regulations
4. Does not address the issue of RIN-less renewable fuel

The current generation of renewable fuels is blended at the truck rack in most cases, and downstream of the truck rack to a lesser extent for ethanol and for biodiesel. With the grandfathering provisions, there will be a significant amount of first generation biofuels in the market for a long time. It is the party that has title to the gasoline and diesel at the truck rack that controls how much renewable fuel, if any, is blended (absent state clear gasoline laws). The current and proposed form of the regulations relies on an indirect incentive for the regulations to be workable since the parties that control what if any renewable fuel is added to gasoline and diesel at the truck rack are not necessarily RFS obligated parties.

Due to existing market structure, some refiners produce more gasoline and diesel than they have title to at the truck rack. They sell product in the spot market to other refiners and to distributors. These refiners are naturally short RINs. Other refiners are in the opposite position and are naturally long RINs. Thus, there is an uneven playing field between refiners. Refiners own the vast majority of gasoline and diesel fuel at the rack level. Changing the designation of obligated party would mainly impact refiners.

There also is an uneven playing field between obligated parties and renewable fuel blenders. Since obligated parties have a legal obligation to purchase a RIN, they are always at a market disadvantage versus the seller of the RIN, especially if the seller is not an obligated party and does not have a legal obligation to sell the RIN. There are major marketers, who are title holders at terminals (i.e., provide finished transportation fuels) and have significant market share in some areas, however, that have no RFS obligation. They can choose to blend or not depending on economics and customer preferences. In addition to creating market distortion and an un-level playing field, this same situation could result in the obligated parties hitting the blend wall earlier than projected (i.e., marketers that have no RFS obligation and choose not to blend effectively put higher percentage RFS obligation on refiners at an earlier time).

There also is no obligation for a renewable fuel blender to blend a potentially more expensive advanced renewable fuel. In fact, the current regulations do not directly require renewable fuels to be blended. This is a key structural flaw when market economics do not support blending renewable fuels. This issue will be magnified in the RFS2 program if, as expected, there is RIN-less renewable fuel in the market (see NPRA's comments on Section III.B.4.b of the preamble).

The current designation of refiners and importers as obligated parties is no longer a workable option given the changes in the RFS2 requirements versus the RFS1 requirements. In addition, the current regulations have already had unintended consequences. Unlike most fuel regulations, the RFS1 and RFS2 regulations are not about changing the petroleum-based fuel before it leaves the refinery; they are about changing what is added to the petroleum-based fuel at the truck rack and offering alternative renewable fuels at the truck rack.

The structure of the current RFS1 regulations makes the regulations less achievable when the RFS2 volumes require renewable fuel to be blended into essentially all of the U.S. gasoline pool. Because the parties that have control of the gasoline and diesel at the rack may not have a RFS obligation, there is no direct incentive for them to blend renewable fuel into the gasoline or diesel. The current regulatory structure is relying on the market prices of renewable fuels, gasoline, diesel and RINs to provide an incentive for the blending of mandatory volumes of renewable fuels. This indirect incentive is not as strong as a direct RFS obligation and, depending on market prices, may not be any incentive at all.

EPA's primary reason for making refiners and importers the obligated party instead of renewable fuel blenders or those parties that hold title to the fuel at the truck rack was to minimize the number of parties impacted by the regulations. With ethanol now approaching 100% penetration in the gasoline pool (at least at 10% or lower blends), all of these parties will be reporting under the current RFS1 regulations. Changing the definition of obligated party to providers of finished transportation fuels will not significantly increase the number of parties reporting to the EPA. In addition, EPA's proposed EPA-moderated RIN trading system (EMTS) should alleviate any enforcement or compliance concerns.

Making the blender who is responsible for turning RBOB and CBOB into finished fuels the obligated party, whether the RBOB or CBOB is at or below the rack, will go a long way in leveling the playing field among all parties. It will also address state clear gasoline regulations so long as the regulations do not require full octane conventional gasoline to be offered for sale. It will also address the issues of RIN-less renewable fuel being in the market by minimizing or eliminating the potential incentive for renewable fuel blenders to blend RIN-less renewable fuel. Since CBOB and RBOB must be blended with ethanol to produce a finished gasoline, choosing the blender as the obligated party is a workable option.

Making the title holder of finished conventional gasoline, RFG (without oxygenate), and diesel at the truck rack the obligated party will address the remaining transportation fuel at the rack. Since these fuels do not require addition of any renewable fuel to become finished fuels, it is impractical to move the compliance point below the rack for these fuels. This change along with the change in BOBs will level the playing field among all parties as much as is practical, and minimize the potential for state regulations and RIN-less renewable fuel to work against achieving the goals of the RFS2 program.

The modification to the definition of obligated party will still work well when 2nd and 3rd generation renewable fuels are developed that can be produced or blended into transportation fuels at the refinery. The producers of these fuels will still be able to assign RINs and the refiner producing or blending these fuels will get the RINs.

In section III.G.4 of the preamble (74 FR 24963), the Agency proposes several other alternatives to those mentioned above. NPRA does not support any of these alternatives and believes that they will either be unworkable or not correct the current problem with the RFS2 regulations as proposed.

In section III.H.4 of the preamble (74 FR 24965), EPA proposes allowing renewable fuel producers to separate and sell RINs to obligated parties as a "solution" to the issue of an uneven playing field. The NPRA strongly opposes this option. This "direct transfer" approach would just change the location of the uneven playing field to between refiner/importers and renewable fuel producers. This option would not address the issue of state clear gasoline regulations and RIN-less renewable fuel working against the goals of the RFS2 program. In addition, as the EPA stated in section III.B.4.b of the preamble (74 FR 24936), "… this approach could potentially place obligated parties at greater risk of market manipulation by renewable fuel producers…". While the EPA may favor this approach because it simplifies the regulations, NPRA believes that the EPA-acknowledged risks are unacceptable, especially when the hybrid approach to obligated parties is a valid workable solution.

If the Agency does select the direct transfer option, EPA should restrict the sale of RINs to obligated parties, as proposed in the NPRM. However, NPRA does not support the proposed auction approach for RINs that a renewable fuel producer does not sell. Instead, the EPA should require that by the 15th of every month, the renewable fuel producer must have sold all of it RINs from the previous month's production. There will always be a market clearing price at which renewable fuel producers will be able to sell their RINs to meet their sales requirement. Introducing an auction mechanism is an unnecessary complication. NPRA does not support using the proposed EPA-moderated RIN trading system as a vehicle to facilitate RIN purchases and sales beyond the voluntary listing of contact information only by buyers and sellers.

4. **EPA's assessment of the statutory requirements of the cellulosic biofuel waiver provision is appropriate.**

We believe the statutory language leaves the Agency with little discretion. In the event that a waiver is required by the annual assessment of cellulosic biofuel capability, EPA must make available to obligated parties at their discretion allowances up to the amount of the revised cellulosic biofuel requirement. Hence, it becomes the obligated party's decision to what extent he will actually physically procure and blend cellulosic biofuel or rely on purchased allowances when he makes his annual compliance demonstration. We support EPA's proposal that such allowances cannot be traded or banked for future use, but would be allowed to meet the cellulosic biofuel requirement, the advanced biofuel requirement, and the total renewables requirement. Use to meet all three requirements must be allowed due to the nested nature of the mandates.

In making its annual assessment of cellulosic biofuel capability, if EPA determines that a waiver is needed, we urge EPA to also adjust the advanced biofuel and total renewables requirements by the same volume as the cellulosic adjustment. If EPA adopts a 30 year averaging and zero discount rate for LCA, it is unlikely there will be any advanced biofuel to make up the cellulosic shortfall. Under no circumstances should EPA ever adjust only the advanced biofuel requirement and leave the total renewable requirement unchanged. Such an action would allow the use of grandfathered biofuels that need not provide any GHG reduction to replace cellulosic biofuels that are required to achieve at least a 60% lifecycle GHG emissions reduction.

Also critical when EPA is making its annual assessment of cellulosic biofuel capability is relying on demonstrated production capability. As evidenced in this proposal, reliance on "planned" capability for such new and unproven technologies is fraught with great risk. EPA's reliance on the plans by one potential cellulosic biofuel supplier to supply 70% of the 2010 cellulosic biofuel volume with as yet undemonstrated technology is not an appropriate evaluation of capability. As evidenced by the recent publicity, this supplier, Cello Energy, has yet to demonstrate the production of any cellulosic biofuel product, and has had a judgment in the amount of $10.4 million entered against them by an Alabama jury that found their technology claims to be fraudulent. Moreover, one of the investors who sampled the product from this process had those samples analyzed and the samples were found to contain no cellulosic biofuel, only petroleum diesel that Cello claims is a "carrier" oil in the process. When assessing new technologies, EPA must adopt a higher standard that capability must be demonstrated both in terms of the actual fuel being produced and the capacity of the plant to operate reliably at some demonstrated operating capacity. Obligated parties must not be put in the position of being forced to carry deficits forward due to the unreliability of new technology, or EPA's overly optimistic acceptance of new technology capability claims.

5. **NPRA strongly supports EPA's proposal that if it reduces the cellulosic biofuel mandate, then cellulosic biofuel allowances bought from EPA may also be used to meet the obligated party's RVOs for Advanced Biofuels and the general RFS.**

The revised statutory requirements specify the volumes of cellulosic biofuel, biomass-based diesel, advanced biofuel, and total renewable fuel that must be used in transportation fuel each year. Under EISA, EPA must reduce the cellulosic biofuel requirement to the extent projections indicate that the volume expected to be produced in the next year will be less than the volume specified in the Act. If such is the case, EPA is required to provide a number of cellulosic credits for sale at the price specified by the Act.

Under the currently proposed changes, EPA would issue such credits or allowances in the amount of the reduced cellulosic biofuel requirement and allow them to be used to show compliance not only with the cellulosic biofuel requirement, but also the advanced biofuel and renewable fuel requirements. NPRA supports this flexibility of allowances and believes this is consistent with the Act. The Act does not provide any indication that allowances should be treated any differently in meeting an obligated party's obligations under the CAA section 211(o) than would the use of a cellulosic biofuel RIN. Since a cellulosic biofuel RIN can be used to meet the advanced biofuel and total renewable fuel standards in addition to the cellulosic biofuel standard, it is consistent that cellulosic biofuel allowances can be used for meeting these same standards. Additionally, with the limitations imposed on their purchase, such that an obligated party can only purchase these allowances once it demonstrates to the EPA that it does not own sufficient cellulosic biofuel RINs to meet its compliance, the intent of the Act to promote the use of renewable fuels is not being hindered.

6. **Standards for 2011 should be announced by the Agency by the end of November 2010.**

EPA plans a notice-and-comment rulemaking each year on the subsequent year requirements. From Section II.A.8. of the NPRM:

> Once the RFS2 program is implemented, we expect to conduct a notice-and comment rulemaking process each year in order to determine the appropriate standards applicable in the following year. We therefore intend to issue an NPRM in the spring and a final rule by November 30 of each year as required by statute.[12]

74 FR 24915.

NPRA supports notice-and-comment, but observes that EPA lacks statutory authority to impose EISA Total Advanced Biofuel renewable mandates for 2010 until RFS2 final rules become effective.

7. **The current 20% cap on the use of last year's RINs for RFS compliance should be increased to 40%.**

[12] Also 74 FR 24955 and 80.1405(b).

The industry now has a couple of years experience with the current RIN system. This experience would support a case for increasing the rollover cap to 40% at proposed 80.1427(a)(5). The time required for RINs to move through the system can be as long as 6 weeks, making it difficult to utilize previous-year RINs that were generated near year-end in current year reporting. The 6-week time includes production of the renewable fuel, testing and assigning RIN values and moving the renewable fuel volume to the point of blending which is the point where some of the RINs are being stripped. Increasing the rollover cap to 40% allows these end-of-year renewable fuel volumes to be more readily incorporated into RFS2 compliance strategies. The higher cap would also provide more flexibility given higher RFS2 volume requirements.

8. NPRA supports the Agency's proposal for defining renewable diesel as co-processed or not co-processed.

NPRA supports EPA's proposed definition of co-processed. This definition enables manufacturers of non-ester renewable diesel to categorize their product as biomass-based diesel by choosing to operate existing or modified equipment in a blocked out or sequential operation rather than processing the renewable feedstock simultaneously with petroleum feedstock. This provides additional flexibility to meet the biomass-based diesel requirement in the most cost effective manner.

9. NPRA supports retaining the energy density-based approach to equivalence values.

An energy density-based approach helps provide a level playing field for all existing and future potential renewable fuels. In general, it costs more to produce renewable fuels with higher energy content, putting them at a disadvantage. Continuation of an energy density-based RIN system would provide some additional incentive for production of these higher energy content renewable fuels. The simplest approach, and the one preferred by NPRA, would be to provide weighting factors and the factored RIN volumes would be used to meet the standards (i.e., the biomass-based diesel standard). EPA has indicated that even under an energy density-based approach, compliance calculations for biomass-based diesel would be treated as straight volume-based requirements. This approach would still allow the additional weighted RIN volume to be used toward meeting the Advanced or Total standard. This approach, although not our first choice, is preferable to the option of no energy density-based approach at all.

10. NPRA objects to E85 producer registering as a refiner.

The Preamble contains discussion relative to the ASTM E85 volatility specifications and the need, in some situations, to blend a higher volatility blend component into E85 in order to meet the ASTM standard (74 FR 25007). The preamble indicates this action would render the terminal a "refinery" and asks whether EPA should provide any flexibilities in complying with the refiner requirements. E85 is an alternative fuel and is not subject to EPA's Reformulated Gasoline or Anti-Dumping regulatory provisions. The preamble references the butane blending regulations as an example. However, these two situations are not analogous. When butane is blended into gasoline at a terminal, the resulting product is still gasoline and is sold as gasoline, even though it has been altered from what was certified at the refinery gate, thus necessitating the regulatory procedures around butane blending. Conversely, a terminal would produce E85 by in-line blending of denatured ethanol, gasoline, and a higher volatility component, such as pentane, while loading the truck. The resultant product is not gasoline, but an alternative fuel, E85, which is not subject to EPA's Reformulated Gasoline or Anti-dumping regulatory provisions. The gasoline in the terminal tank would remain unaltered and could be sold as gasoline across the rack. The action of producing E85 in this manner does not result in the terminal becoming a "refinery"; therefore, the facility would not be subject to the refiner requirements solely due to E85 production activity.

<u>Setting standards</u>

NPRA supports voluntary consensus standards. EPA is also a supporter of commercial specifications.

OMB Circular A-4 provides guidance on the development of regulatory analysis:[13]

> The Presumption Against Economic Regulation
> Government actions can be unintentionally harmful, and even useful regulations can impede market efficiency. For this reason, there is a presumption against certain types of regulatory action. In light of both economic theory and actual experience, a particularly demanding burden of proof is required to demonstrate the need for any of the following types of regulations: …
>
> - mandatory uniform quality standards for goods or services if the potential problem can be adequately dealt with through voluntary standards …

pp. 6-7.

EPA should follow this guidance from OMB, let the marketplace work, and not step in to regulate when there is a voluntary standard.

11. Registration, Recordkeeping Requirements for Renewable Fuel Producers

Section 80.1450 sets forth the requirements for renewable fuel producers to register with EPA. As proposed, all renewable fuel producers would be required to make a showing to EPA, certified by an independent 3rd party, to establish the pathway for the renewable fuels produced at each facility so that the renewable fuels produced at each facility can be classified appropriately under the RIN system. It is clear that this will be a burdensome process for renewable fuel producers and that it will take considerable time for all renewable fuel producers to complete the registration process. It is imperative that EPA provide

[13] Subject: Regulatory Analysis, September 17, 2003.

sufficient lead time at the beginning of this program to allow these registrations to occur. If sufficient time is not provided, it could limit the availability of RINs.

Section 80.1451 contains onerous documentation requirements for renewable fuel producers. For each batch of renewable fuel produced, the renewable fuel producer would be required to maintain records to establish that the feedstock used meets the definition of "renewable biomass" as that term is defined in section 80.1401. EPA should consider other options to facilitate the ability of renewable fuel producers to demonstrate that the feedstocks they use meet the definition of "renewable biomass." In particular, EPA should require producers to make a one time demonstration to EPA during the registration process to establish the typical source of feedstocks and the process at the facility. Thereafter, rather than requiring each producer to amass the records that EPA proposes for each feedstock for each batch, EPA should recognize certifications from third party organizations such as the Roundtable for Sustainable Palm Oil, the Roundtable for Responsible Soy, the Better Sugarcane Initiative, and the Roundtable for Sustainable Biofuels, as sufficient. At a minimum, in lieu of the burdensome recordkeeping and certification requirements that EPA proposed, the Agency should provide renewable fuel producers the opportunity to establish a 3rd party organization similar to the RFG Survey Association to audit compliance with the Act to ensure that biofuels are in fact made from "renewable biomass" without imposing requirements on individual producers to track every kernel of corn, bean of soy, or cane of sugar used to produce biofuels.

12. EPA should carefully evaluate future biomass-based diesel production capability.

EPA will need to identify the annual regulatory volume for the first year of the RFS2 program for biomass-based diesel. The first year of the RFS2 program is likely to be 2011. It appears certain that soybean- and other vegetable oil-based biodiesel will not qualify as biomass-based diesel because of land use change factors. Therefore, the expected biomass-based diesel regulatory volume mandated for 2011 will require an assessment of the capability to produce and import waste grease-based biodiesel.

To identify an appropriate regulatory volume for 2011, the Agency should project actual supply in 2011. EPA should not just rely on nameplate production capacity and assume that all plants will operate at 100% capacity utilization throughout 2011.

EPA did not have an actual biodiesel production value for 2008 for Figure 1.5-17 in the draft RIA.[14] Biodiesel consumption, production, import and export data are available from EIA:[15]

[14] "Draft Regulatory Impact Analysis: Changes to the Renewable Fuel Standard Program," EPA-420-D-09-001, May 2009, p. 199.

[15] http://www.eia.doe.gov/emeu/mer/pdf/pages/sec10_8.pdf

	Million gallons			
	Production	Consumption	Imports	Exports
2006	250	261	45	35
2007	490	358	140	272
2008	683	320	315	677

Currently, EIA collects biodiesel production data directly from producers each month (Form EIA-22M).[16] This includes extensive data on feedstocks.[17] This is a resource that will be very useful in EPA's evaluation of waste grease-based biodiesel production.

D. LIFECYCLE GHG EMISSIONS ANALYSIS

1. NPRA supports 30 years/0% discount rate.

As regards EPA's lifecycle analysis for RFS2, NPRA commends EPA for its scientific approach and diligence in examining the full gamut of potential impacts from the production and use of various biofuels. NPRA agrees with EPA's interpretation that EISA requires that EPA consider both direct and indirect land use change impacts.

As regards the averaging period and discount rate to be applied, we favor the use of 30 years for averaging and a zero discount rate as a more conservative approach. The shorter time period gives more weight to the known, more immediate, effects of carbon release from clearing, burning and loss of soil sequestration while a zero discount rate values future impacts the same as current impacts. We believe 100 years of assumed use for a given biofuel and its pathway is simply assuming too much about future decisions beyond our control. In addition, the interests of future generations should not be discounted as they will have to pay for any misdirection resulting from current decisions. If this more realistic averaging period and discount rate results in an unworkable program due to insufficient supply of qualifying biofuels, EPA should use its general waiver authority to adjust the RFS2 requirements accordingly.

Finally, we support periodic reevaluations and updates to the LCA (perhaps every three years, initially) to adjust the analysis as technology and modeling evolves. In addition, we would urge EPA to continue efforts with CARB to harmonize LCA methodologies to the extent possible, and be able to explain differences where authorizing documentation precludes harmonization.

Appendix B contains additional detailed comments on EPA's LCA approach.

[16] http://www.eia.doe.gov/cneaf/solar.renewables/page/forms/form22m.pdf

[17] Canola oil, castor oil, coconut oil, corn oil, cottonseed oil, palm oil, peanut oil, soybean oil, sunflower oil, tung oil, other vegetable oil, poultry fat, tallow, white grease, other animal fat, recycled yellow grease, other recycled feedstocks, algae, and other.

2. **The scope of grandfathering from the minimum GHG emissions reduction should be narrowed.**

EPA has proposed to extend the definition of "grandfathering" far beyond what Congress intended. Congress specifically used the phrase "under construction". Since the actual construction phase of most corn-based ethanol and FAME biodiesel plants is less than one year, EPA should be using a 12 month time period after December 19, 2007 instead of a 36 month time period.

NPRA agrees with EPA that any ethanol plant that is fired with natural gas, biomass or any combination thereof for calendar years 2008 and 2009 should be considered grandfathered and should be treated like grandfathered ethanol facilities for as long as they continue to burn natural gas, biomass or any combination thereof. However, NPRA believes that grandfathering should only apply to originally approved baseline volumes. Any new volume production, no matter how small, should be required to meet the minimum 20% GHG emissions reduction threshold. We do not agree with EPA extending any tolerance to this baseline volume.

NPRA does not believe that grandfathered facilities should be exempted indefinitely and agrees with the 15 year expiration of exemption for all grandfathered facilities. We agree that biofuel facilities should lose their grandfathered status if they make any changes that result in an increase in GHG emissions for the baseline volumes. We believe that EPA should limit grandfathering to only the fuel pathways that applied in 2007. We agree that if coal-fired units are replaced on grandfathered facilities, they must be replaced by natural gas- and/or biomass-fired units.

We agree that EPA should require grandfathered facility owners to annually report, starting in 2010, the expenses for replacements, additions and repairs and that EPA should use these reports to determine when the facility effectively becomes new due to rebuilding or modernization. Once EPA determines that the facility is "new", it shall no longer have grandfathered status.

These limitations to the exception are consistent with congressional intent. Congress clearly intended the renewable fuels provisions of EISA to result in greenhouse gas emission reductions. It is consistent with that intent to limit the exemption to the volumes produced at the date of enactment. If it is not limited, instead of improving existing facilities and building new more efficient facilities to produce biofuels with greater greenhouse gas emissions reduction benefits, renewable fuel producers are likely to simply modify existing facilities to producer greater volumes of the least-performing biofuels. Sunsetting the grandfathering provision is also consistent with congressional intent as it will ultimately encourage investments in the most efficient facilities resulting in better performing biofuels and greenhouse gas emissions reduction benefits.

NPRA would oppose any effort to apply grandfathering indefinitely or to allow any production increases above the approved baseline to be considered to be covered under the grandfathering provisions.

3. **NPRA supports the Agency's proposal that GHG grandfathering applies only to the general RFS, and not advanced biofuels, biomass-based diesel or cellulosic biofuels.**

NPRA supports EPA's conclusion that the law only grandfathers biofuels from the general renewable fuel requirement, and does not create an exemption from the biomass-based diesel, advanced biofuel, or cellulosic biofuel categories. The law clearly limits the exemption to the minimum 20 percent greenhouse gas emission reduction requirement for the general renewable fuel category, and does not exempt biofuels from the requirements of the other categories.

4. **NPRA does not support an adjustment to the biomass-based diesel minimum GHG emissions reduction threshold, nor any of the averaging approaches outlined by EPA as a mechanism to qualify biodiesel that would otherwise not qualify as biomass-based diesel.**

If the final lifecycle analysis does not qualify vegetable oil-sourced biodiesel as biomass-based diesel, EPA should not resort to averaging techniques to artificially qualify such biofuels. Such averaging does not further the aims of GHG reduction inherent in the EISA RFS expansion. Rather, at its own initiative, EPA should initiate a general waiver process to reduce the biomass-based diesel requirement to the level of available biodiesel or renewable diesel that does qualify as biomass-based diesel, taking into account geographical and seasonal factors.

Even if EPA believes such averaging is necessary to make the RFS2 program workable, NPRA counsels caution in setting such a precedent. A similar approach could be proposed in the future to expand the use of grandfathered biofuels that do not serve to reduce GHGs, but can be artificially enhanced by averaging with new advanced biofuels. Such averaging could serve to retard development of new advanced biofuels if they will only be used to upgrade non-qualifying biofuels to the minimum threshold GHG reduction.

If EPA proceeds never-the-less with an averaging approach to qualify vegetable oil-sourced biodiesel as biomass-based diesel, NPRA urges EPA to utilize an averaging mechanism that allows both producers and obligated parties to average the appropriate ratio of RINs. This will provide the greatest degree of flexibility, and flexibility will be needed to overcome geographical and seasonal differences.

If EPA finalizes the RFS2 rulemaking for implementation on January 1, 2010 or January 1, 2011:

	D Code
RFS2 Cellulosic ethanol	1
RFS2 Cellulosic diesel	2
RFS2 Biomass-based diesel	3
RFS2 Vegetable oil-based biodiesel	4
RFS2 Waste grease-based biodiesel	5
RFS2 Advanced Biofuel	6
RFS2 Renewable Fuel	7

If EPA finalizes the RFS2 rulemaking for a partial year implementation, then D codes should be assigned as follows:

	D Code
RFS1 Cellulosic	1
RFS1 Other	2
RFS2 Cellulosic ethanol	3
RFS2 Cellulosic diesel	4
RFS2 Biomass-based diesel	5
RFS2 Vegetable oil-based biodiesel	6
RFS2 Waste grease-based biodiesel	7
RFS2 Advanced Biofuel	8
RFS2 Renewable Fuel	9

For example, for the case of full year implementation, if a renewable fuel producer produces waste grease biodiesel, and only waste grease biodiesel, they would use D=5. If, however, the renewable fuel producer produces both waste grease biodiesel and soy biodiesel, they might blend them in the appropriate proportions and use D=3, assuming averaging is permitted. If the producer who has both soy and waste grease biodiesel does the averaging, he uses the 3 code and the obligated party doesn't have to do anything but keep the code. If an obligated party buys unaveraged waste grease sourced biodiesel (code 5) and soy biodiesel (code 4), he can average the two in the proper proportions and change the D code to 3 (or however EPA wants that shown). Obligated parties need the averaging flexibility for both to account for seasonal and geographic variations. NPRA recommends that EPA use the available D codes to provide as much granularity and flexibility as possible. Adding only one D code does not provide sufficient flexibility. See NPRA's comments in section E. 6. Regarding flexible D codes.

NPRA

5. EPA should add direct and indirect N_2O emissions to domestic agriculture LCA.

EPA committed to adding direct and indirect N_2O emissions to the domestic agricultural sector impacts of the lifecycle GHG emissions analysis (74 FR 25027, 25028).[18] NPRA supports this addition. NPRA supports sound science and this is a component that should not be ignored or skipped. This is an appropriate application of President Obama's pledge that science, not politics, would guide his Administration's approach to public policy issues.[19]

Many scientists are concerned that the GHG emissions resulting from biofuel production and associated agricultural practices could effectively negate or even reverse any reduction in emissions that could be achieved by significantly expanding the use of biofuels as transportation fuels. Nobel Prize winner Paul Crutzen concluded that increased biofuels production is accompanied with a dramatic increase in emissions of N_2O, which has nearly 300 times greater warming potential than CO_2.[20] This would offset much of the GHG emissions reductions from the displaced petroleum fuels. This paper clearly shows that N_2O emissions must be considered in lifecycle analyses of biofuel production, especially for biodiesel from rapeseed and corn ethanol. Crops with less nitrogen demand, such as grasses, have more favorable climate impacts.

6. 2005 baseline

During the public hearings on the proposed RFS2 rule, several parties suggested that EPA should change the methodology for determining the greenhouse gas emission reductions of biofuels by changing the gasoline and diesel baselines. We agree with EPA's stated view that EISA clearly specifies the baseline:

> (C) Baseline Lifecycle Greenhouse Gas Emissions. – The term 'baseline lifecycle greenhouse gas emissions' means the average lifecycle greenhouse gas emissions, as determined by the Administrator, after notice and opportunity for comment, for gasoline or diesel (whichever is being replaced by the renewable fuel) sold or distributed as transportation fuel in 2005.

We agree with EPA's interpretation of this statutory provision, and EPA's conclusion that Congress did not authorize EPA to go beyond this definition.

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18 Also "Draft Regulatory Impact Analysis: Changes to the Renewable Fuel Standard Program," May 2009, EPA-420-D-09-001, pp. 331-333.

19 March 9, 2009 memorandum on "Scientific Integrity."

20 P. J. Crutzen, A. R. Mosier, K. A. Smith, and W. Winiwarter, "N_2O Release from Agro-Biofuel Production Negates Global Warming Reduction by Replacing Fossil Fuels," Atmos. Chem. Phys., 8, 389-395, 2008.

E. RENEWABLE IDENTIFICATION NUMBERS

1. The reference to "home heating oil" in the proposed definition of Additional Renewable Fuel should be clarified.

As discussed in Sections III.B.1.e and III H.2 of the proposed rule and in keeping with the statutory definition of *additional renewable fuel*, EPA proposes to allow RINs associated with any renewable fuel used in home heating oil or jet fuel to be separated at the time of blending and used for compliance purposes. NPRA supports this decision as well as EPA's proposal that volumes of home heating oil and jet fuel would not be included in the RVO calculation for an obligated party. Since the annual RVO percentage is based on the statutory volume requirement in EISA divided by the volume of transportation fuel, not including home heating oil and jet fuel volumes in the determination of an obligated party's RVO will not negatively impact meeting the total annual renewable fuel mandate.

Proposed § 80.1429(f) states that "*Any party that uses a renewable fuel in a commercial or industrial boiler or ocean-going vessel (as defined in § 80.1401), or designates a renewable fuel for use in a boiler or ocean-going vessel, must retire any RINs received with that renewable fuel …*". This requirement either makes the end user or other downstream party an obligated party or presumes that a blender/refiner blending renewable fuel into diesel, fuel oil or other distillate and separating RINs from the renewable fuel knows the intended use of that fuel at the time of blending, which is often not the case. The proposed language places the burden of retiring such RINs on the party that *uses* the renewable fuel or *designates* it for use in a commercial/industrial boiler or ocean going vessel. However this is usually not the same party as the blender or refiner. This downstream party would not be receiving RINs with the blended renewable fuel and therefore would receive no RINs to retire. It is unclear if EPA intends for the user/designator to go back upstream and notify the blender of the end use, or acquire and retire RINs (making them an obligated party), but this would place an unreasonable burden on all parties involved and could occur after RINs had already been transferred to other parties or even used for compliance purposes.

NPRA recommends that RINs associated with any renewable fuel blended into diesel, heating oil or other distillates be allowed to be separated and used for compliance purposes without regard to ultimate end use of that fuel. Distillate usage in stationary sources and ocean-going vessels is minor compared with other uses. Allowing RINs associated with such usage to be used for compliance rather than being retired will not change an obligated party's RVO, will not result in less renewable fuel being used and will only contribute to meeting the renewable fuel volume mandates in EISA.

2. NPRA supports continuation of the 38 digits.

We fully support maintaining the 38-digit RIN structure. This current methodology can easily manage all expected changes associated with RFS2 (i.e., revising D codes) and will minimize the cost to all users by avoiding costly IT infrastructure restructuring.

3. **The purchase of separated RINs should be restricted to obligated parties.**

In section III.H.4 of the preamble (74 FR 24965), EPA proposes not allowing non obligated parties to purchase RINs under the proposed "direct transfer" approach. While the NPRA does not support EPA's proposed "direct transfer" approach (see comments on Designation of Obligated Parties), NPRA agrees that non obligated parties should not be allowed to purchase RINs under the "direct transfer" approach. Furthermore, the NPRA supports restricting the purchase of separated RINs to only obligated parties regardless of the approach adopted in the final regulations.

Allowing non obligated parties to purchase RINs creates an un-level playing field. A free market is a market where both the buyer and the seller have the option to conduct a transaction. This is not the case when an obligated party is purchasing a RIN from a third party or speculator. The obligated party has a legal obligation to meet and must buy from someone while the third party seller has no legal obligation to sell.

Allowing non obligated parties to purchase RINs may lead to higher prices and increased price volatility. Third parties will enter the RIN market to speculate and make money, not to further compliance. Since there is no free lunch, if they make money then the obligated parties by definition must be paying more for RINs than if the third parties were not in the market. For example, once a third party has covered their purchase costs or met an internal profit goal, there is nothing to stop them from holding out for a market premium on the remaining RINs that they own. If they do not get their asking price they can always elect to breakeven.

Allowing non obligated parties to purchase RINs will lead to higher costs to the consumer and act as another hidden tax. The regulations should not invite the opportunity for non-obligated parties to speculate and potentially manipulate the market.

Other fuel credit markets and the RFS market to date have not needed third parties to take title to fuels credits in order for the credit market to work and for adequate liquidity to exist. In addition, the proposed EPA – moderated RIN Trading System could be used as a voluntary listing of contact information of potential buyers and sellers. Note that the NPRA does not support EPA acting as a broker, buyer or seller of RINs beyond the statutory requirement for EPA to offer cellulosic credits for cellulosic biofuel when a waiver is necessary.

4. **NPRA opposes the Agency's proposal to require that RIN prices be reported to EPA.**

NPRA recommends that EPA should follow the same RIN pricing reporting requirement as set in RFS1. Reporting RIN pricing, in general, could have an adverse affect on Confidential Business Information (CBI) and Corporate Intelligence (CI). All company-specific data should be automatically considered CBI. Public disclosure of company-specific RIN pricing data can lead to unintended consequences such as increased opportunity for market manipulation, speculation and increased risk of price volatility.

EPA's RIN reporting proposal is too loosely defined (i.e., transaction detail required) and can present unintended and unanticipated harm to both CI and CBI. Information in EMTS regarding RIN volume generation and trading, both purchases and sales, could be analyzed to understand production information (i.e., production product and quantities). Should RIN price information be required on a timely and detailed basis, CBI information could assist competitors' operational and financial strategies.

EPA lacks statutory authority to require reporting of RIN prices.

We submit that the EPA lacks specific statutory authority to require burdensome and intrusive reporting of RIN price information with regard to the price of RINs in transactions (whether purchases, trades or sales). Under the proposed regulations in 80.1452, this price information is required whether the RIN is priced separately or included within the per gallon renewable fuel price and after January 1, 2011, this information must be submitted within 3 business days of a transaction, imposing a substantial burden on regulated entities and the marketplace as a whole.

Sections 201, 202, and 210 of EISA cited by EPA in its Preamble for the RFS2 Proposed Rulemaking did not amend the CAA to provide EPA with specific statutory authority for the collection of RIN price information. Instead, the amendments made by these sections of EISA added a new requirement to section 211(o) of the CAA to require EPA to revise existing regulations in order to implement the new RFS program requirements approved as part of EISA. In specific, EISA added the requirement in 211(o)(2)(A)(i) for the EPA Administrator "to ensure that transportation fuel sold or introduced into commerce in the United States (except in noncontiguous States or territories), on an annual average basis, contains at least the applicable volume of renewable fuel, advanced biofuel, cellulosic biofuel, and biomass-based diesel, determined in accordance with subparagraph (B) . . ." This new statutory authority left in place section 211(o)(2)(A)(iii) of the CAA originally enacted by Congress in 2005 as part of the Energy Policy Act of 2005 (PL 109-58, August 8, 2005). Under 211(o)(2)(A)(iii), "Regardless of the date of promulgation, the regulations promulgated under clause (i)—(I) shall contain compliance provisions applicable to refiners, blenders, distributors, and importers, as appropriate, to ensure that the requirements of this paragraph are met."

In the RFS2 Proposed Rulemaking that relies on this authority, EPA requires the submission of data with regard to the prices paid in the private marketplace for RINs. Prices of RINs are not directly related to whether transportation fuel contains the "applicable volume of renewable fuel" and this information is not needed to ensure that the statutory requirements of the Renewable Fuel Standard Program are met.

In the proposed rulemaking EPA indicates several policy reasons for the collection of RIN price information, e.g., to help the Agency anticipate and react to market disruptions and other compliance challenges, to assist in setting future renewable standards and to provide additional market insight with regard to potential waivers (74 Fed. Reg. at 24969). Such policy arguments also lack a sufficient statutory basis.

The potential for future RFS waiver requests also cannot justify the requirement for the submittal of RIN price information. In fact, EPA has already made one RFS waiver determination (73 Fed. Reg. at 47168) (August 13, 2008) in the absence of a specific RIN price reporting requirement.[21] In this action, the EPA considered available RIN price information along with broader economic information and analyses, thereby indicating that continuous submittal of RIN price information ad infinitum is unnecessary.

5. EPA should reduce the burden associated with demonstrating feedstock classification.

The recordkeeping requirements concerning demonstration that feedstocks meet the definition of renewable biomass are very onerous. Some simplifying assumptions should be made and applied that would significantly reduce the recordkeeping burden. Certain types of feedstocks could be declared renewable by list. These would include those that clearly come from agricultural lands such as corn and soybeans. There are few ways that these types of crops would not meet the definition (i.e., someone converted forest land since December 17, 2007 and planted crops, etc.). The burden of having every farmer provide documentation that then must get passed along to the renewable fuel producer seems great when essentially all of certain types of crops would fall into the renewable biomass category. We would encourage EPA to consider ways to reduce the burden associated with demonstrating feedstock classification.

For example, EPA should require producers to make a one time demonstration to EPA during the registration process to establish the typical source of feedstocks and the process at the facility. Thereafter, rather than requiring each producer to amass the records that EPA proposes for each feedstock for each batch, EPA should recognize certifications from third party organizations such as the Roundtable for Sustainable Palm Oil, the Roundtable for Responsible Soy, the Better Sugarcane Initiative, and the Roundtable for Sustainable Biofuels, as sufficient.

6. There should be a flexible RIN "D" code for a renewable fuel that could meet either the biomass-based diesel or the cellulosic biofuel definition.

NPRA *generally* supports the alternative D code definitions in Table III.D.2.a-1 at 74 FR 24946. However, we do not agree that the producer should be allowed to choose whether to categorize his product as either cellulosic biofuel or biomass-based diesel. Rather, we would suggest that EPA create a flexible D code that would denote a fuel that can be counted as either, and that the obligated parties have the ability to choose whether to apply such a RIN to cellulosic or biomass-based diesel.

EPA wrote the following (74 FR 24946):

[21] EPA denied the RFS waiver request from the Governor of Texas.

A diesel fuel product produced from cellulosic feedstocks that meets the 60% GHG threshold could qualify as either cellulosic biofuel or biomass-based diesel. As a result, we are proposing that the producer of such "cellulosic diesel" be given the choice of whether to categorize his product as either cellulosic biofuel or biomass-based diesel. This would allow the producer to market his product and the associated RINs on the basis of market demand. However, we request comment on an alternative approach as shown in Table III.D.2.a-1 in which an additional D code would be defined to represent cellulosic diesel and an obligated party would be given the choice of using cellulosic diesel RINs either to meet his or her RVO for cellulosic biofuel or for biomass-based diesel.

Table III.D.2.a-1 Alternative D Code Definitions To Accommodate Cellulosic Diesel

D value	Meaning under RFS1	Meaning under RFS2
1	Cellulosic biomass ethanol	Cellulosic biofuel
2	Any renewable fuel that is not cellulosic biomass ethanol	Biomass-based diesel
3	Not applicable	Cellulosic biofuel or biomass-based diesel
4	Not applicable	Advanced biofuel
5	Not applicable	Renewable fuel

Under this alternative, producers of cellulosic diesel would assign a D code of 3 to their product rather than being given a choice of whether to assign a D code of 1 or 2. Any obligated party that acquired a RIN with a D code of 3 could apply that RIN to either its cellulosic biofuel or biomass-based diesel obligation, but not both. The advantage of this alternative approach is that it reflects the full compliance value for the product, and hence its potential value to an obligated party. The obligated party is then given the ability to make a choice about how to treat cellulosic diesel based on the market price and availability of RINs with D codes of 1 and 2. We request comment on this alternative approach to the designation of D codes for cellulosic diesel.

The alternative RIN "D" codes proposed by EPA should be promulgated. They provide clear guidance to biofuel producers and compliance flexibility for obligated parties.

Implications of averaging.

NPRA opposes an averaging program to qualify biodiesel that would not otherwise qualify as biomass-based diesel. If EPA proceeds never-the-less with such an averaging program, then D codes may need to be changed. See NPRA's comments regarding averages in section D. 4.

7. **The annual volume threshold should be 10,000 gallons of renewable fuel for refiners and importers who choose not to generate RINs.**

EPA proposes the 10,000 gallon annual threshold at 80.1426(b)(1) and NPRA supports this proposed regulation. This is the same annual volume in the RFS1 regulations at 80.1126(b) and should be maintained in RFS2.

8. **RIN numbers should not be required to appear on a PTD in their entirety.**

The proposed regulations at 80.1453(c), 80.1453(a)(5)(i), and 80.1428(a)(6) could be interpreted to mean that all 38 characters of each RIN must be on a PTD. PTDs should be required to show the number and type of gallon-RINs being transferred, but not all 38 digits. Given EMTS, it is unnecessary to require 38 digits on PTDs. These proposed regulations could cause problems when the PTD shows 38 digits that do not match the RINs transferred within EMTS. This potential for a discrepancy would undercut the value and benefits of the EMTS program and create new reconciliation headaches that don't exist today in RFS1 without the EMTS.

9. **Monthly reporting should not be required in 2010 for all RIN-owning parties.**

The proposed regulations at 80.1452(c)(1) and 80.1452(d)(1) require monthly reporting of RIN transactions. This should not be promulgated. The RFS2 regulations will not be effective on 1/1/10. The RFS2 regulations will be effective when the EMTS is activated, probably 1/1/11. Therefore, there is no need to submit monthly reports when EMTS is operational.

10. **A downstream party should not be required to adjust records, reports and compliance calculations because an upstream party made a mistake and distributed invalid RINs.**

Once EPA accepts a new RIN in EMTS from a registered renewable fuel producer or importer, then downstream parties should not have to deal with any mistakes or incorrect RINs. For example, assume that some RINs were generated incorrectly because the volume was in error. If too many RINs were generated compared to the volume of renewable fuel, that renewable fuel producer or importer owes EPA replacement RINs; the RIN producer, if still in business, could buy RINs to replace the incorrect RINs, retire the replacement RINs and balance the account. Downstream parties should not be bothered. If the RIN generator is out of business, then the next downstream party would be liable. All downstream parties should not have to find the problem RINs and find someone upstream to replace them with valid RINs. Downstream parties should have the peace-of-mind that RINs in EMTS will not be recalled (at least as long as the next upstream party is still in business). The proposed regulation at 80.1431(b) should be edited such that the upstream party makes peace with EPA and EMTS when an invalid RIN is discovered and downstream parties will not be bothered.

11. The attest engagement requirements should be greatly minimized.

The proposed attest engagement requirements at 80.1464 should be greatly minimized by EMTS, in particular noting the attest of the PTDs and transactions between the transferor and transferee. The PTD information will be captured by EMTS at the time of the transaction and each party must acknowledge the transaction within EMTS and thus further attesting of these transactions and documents is not necessary. EMTS will eliminate the transaction errors which otherwise necessitate the respective portions of the attest requirements. Some of the attest steps that would remain include verification of RVO determination, volume of renewable fuel owned as compared to assigned RINs owned, volume of renewable fuel blended as compared to the number of RINs that were separated, and volume of renewable fuel produced and imported as compared to RINs generated (by type). It is expected the that EPA will be auditing the EMTS itself to assure continued integrity of transaction data - not to mention the everyday “testing” by users to acknowledge the transactions; if there is a problem, it will become apparent sooner than later.

12. The RFS2 regulations should be flexible when requiring information submission to EPA within a short period of time after a renewable fuel is produced or imported.

It is reasonable to expect information to be submitted to EPA when a renewable fuel is produced or imported. The proposed requirement “within three (3) business days” in 80.1452(e)(2) may be too rigid.

When ethanol is imported and denatured, it usually takes a few days for the inspector to issue a report. If a deadline for RIN generation is imposed, please allow sufficient time for the importer to receive documentation from the inspector. We would suggest some flexibility because three days may not always be realistic. A week might be reasonable. Certainly, a renewable fuel should not be shipped or traded until a RIN has been validated in EMTS.

13. The regulations should limit the ability of producers and importers to produce or import renewable fuel that does not have RINs. In addition, the RFS2 regulations should take into account the existence of "RIN-less" renewable fuel in the RFS2 program.

In section III.B.4.b of the preamble (74 FR 24936) and in other sections, the Agency brings up the issue of the existence of renewable fuel in the RFS2 program that does not have RINs ("RIN-less" renewable fuel). NPRA understands that the EPA is considering removing the requirement that renewable fuel producers and importers demonstrate that renewable fuel was not made from renewable biomass. If this is done, demonstrating that renewable fuel was made from renewable biomass will in effect be optional and there will be renewable fuel with no associated RINs or "RIN-less" renewable fuel in the RFS2 program.

The existence of RIN-less renewable fuel and the optional assignment of RINs to renewable fuel by producers and importers introduce several serious program design and enforcement and compliance issues. In the preamble (74 FR 24936 – 24937), EPA acknowledges that: renewable fuel producers may have an economic incentive not to generate RINs due to the cost of verifying their feedstock; renewable fuel producers could potentially manipulate the market for RINs; there could be a shortage of RINs; and the price of RINs could increase significantly, making compliance by obligated parties more costly and difficult than necessary and raising prices for consumers.

In the preamble the EPA discusses relying on the price of RINs in the market to encourage renewable fuel producers to generate RINs where possible. This implies that renewable fuel without RINs will have a lower market price than renewable fuel with RINs. NPRA cautions the Agency on relying on market forces or indirect mechanisms rather than a direct regulatory requirement. Relying on market forces in a free and open market is one thing. However, relying on market forces in a highly regulated market with numerous regulatory requirements that differ between the parties in the market often has unintended consequences such as those now occurring in the RFS1 RIN market. Market forces could have the opposite effect from that intended, and encourage renewable fuel producers not to assign RINs to some of their production in order to drive up the price of RINs.

EPA should require renewable fuel producers to assign RINs (and perform the necessary feedstock certification) if the producer/importer has a reasonable belief that the feedstock is renewable biomass. Currently in the U.S., very little land that was not previously cultivated is being used or is likely to be used in the future to generate feedstock for renewable fuels. The majority of deforestation in the U.S. is due to the expansion of urban areas into forested areas. The majority of new land being farmed is land coming out of the CRP program. It is hard to envision a case where the vast majority of renewable fuel produced in the U.S. would not be produced from renewable biomass.

EPA should also consider limiting the percentage of renewable fuel that a producer or importer could produce or import in a calendar year that does not have assigned RINs. A 1% to 10% maximum would be appropriate.

EPA should establish an exemption procedure for imported renewable fuel so that it can be imported without assigning RINs or providing a demonstration for not assigning RINs (an exemption from proposed 80.1426(b)(2) and (4)) if such imported renewable fuel is not introduced into transportation fuels in the United States and is subsequently exported.

EPA's own market concerns reinforce NPRA's position on several issues.

First, in the preamble (74 FR 24937), the Agency states that removing the restriction that RINs be assigned to batches of renewable fuel and transferred with those batches, and allowing renewable fuel producers to sell RINs separately from volumes of renewable fuel (the "Direct Transfer" approach), could potentially place obligated parties at greater risk of market manipulation by renewable fuel producers. This reinforces NPRA's opposition to the direct transfer approach.

Under the current proposed definition of obligated party and the likely existence of cheaper RIN-less renewable fuel, the proposed regulatory structure along with state "clear gasoline" regulations could result in an economic incentive for renewable fuel producers to not assign RINs and for renewable fuel blenders to purchase RIN-less renewable fuel. This is a structural flaw in the current regulatory proposal that could encourage actions that work against the intent of the regulation and increase the possibility of noncompliance. If there is RIN-less renewable fuel under the RFS2 program, EPA must take this into account when reviewing the other portions of the proposed regulations. Specifically, in this circumstance, NPRA supports making renewable fuel blenders of all BOBs the obligated party.

F. MID-LEVEL ETHANOL BLENDS AND E-15 CONSIDERATIONS

1. NPRA opposes the proposal to approve E15 as gasoline.

NPRA urges EPA to reject Growth Energy's petition[22] for the following reasons: (1) the science on the impact of mid-level ethanol blends on consumer safety, engine performance, and potential environmental harm has not been completed and likely will not be completed for at least two years; (2) the information submitted by Growth Energy in support of its petition is a woefully inadequate foundation upon which to base such an important change in the nation's supply of gasoline; (3) the potential approval of Growth Energy's petition is not an effective short- or medium-term solution to avoiding the "blendwall" problem caused by the increasing conventional biofuels volumes mandated under the Energy Independence and Security Act of 2007 and thus EPA should not rush such an important decision until a scientifically-based rationale can be reached regarding consumer safety, engine reliability, and environmental concerns of mid-level ethanol blends use in all gasoline-powered motor vehicles and engines in use in the United States; and (4) this seemingly modest petition will, if granted, have wide-ranging implications on other federal and state fuels programs and will require a series of complex and lengthy rulemakings to harmonize these programs with the introduction of mid-level ethanol blends.

22 See 74 FR 18228, 4/21/09.

In addition, NPRA also opposes the grant of a "partial waiver" to permit the use of mid-level ethanol blends in some gasoline-powered engines for the following reasons: (1) it would cause significant disruption in the nation's wholesale and retail gasoline distribution infrastructure, widespread consumer confusion and potential misfueling, and potential liability for engine and fuel manufacturers for any damage caused to gasoline-powered engines not compatible with mid-level ethanol blends; and (2) EPA does not have the statutory authority under Section 211(f) of the Clean Air Act to grant a partial waiver.

NPRA supports the prudent development and use of biofuels, including ethanol, to diversify our nation's transportation and nonroad fuels portfolio. However, before the use of mid-level ethanol blends is permitted, EPA has an affirmative obligation to find, based on comprehensive and unbiased test data, that these blends are safe for consumers, do not harm gasoline-powered engines, and do not lead to increases in emissions from these engines that will harm the environment. The data submitted by Growth Energy in its petition does not come close to meeting these admittedly and necessarily high standards, and thus the petition must be rejected.

NPRA's comments submitted to EPA in July 2009 are included in Appendix A.

2. There are several mid-level ethanol blend infrastructure compatibility issues.

Most of the nation's gasoline handling and distribution system from the terminal level through the retail level has been or is in the process of being modified, replaced or recertified to handle ethanol/gasoline blends up to 10 volume percent ethanol. As a result, even small fuel changes, such as changes to E11 or E12, could potentially require the complete replacement of the existing gasoline infrastructure downstream of the blending terminal, and at a minimum will require the reanalysis and recertification of all of these pieces of hardware and repermitting of these locations.

Several current regulations and fire codes have an impact on the use of ethanol blends over 10 volume percent in the existing infrastructure. Concerns regarding existing infrastructure compatibility with ethanol blends over 10 volume percent must be resolved before these fuels can be delivered to the consumer. Research efforts are currently underway and these must be allowed to finish. We must promote the use of sound science and good engineering principles to determine how to proceed without creating issues for consumers, the environment, or fuel marketers. In addition, marketers could be forced into a position of having to dispense several different fuel types (E10, E15, E85, Diesel) at a single retail station or offer these products selectively at different stations in a given area. Regardless, this could in turn require additional underground storage tank and dispenser infrastructure to accommodate the different fuel blends. Infrastructure investments of this nature are very expensive and will be especially detrimental to and difficult for the significant number of retail stations owned by individuals or small businesses. Further, even stations that may have the capital to invest in these upgrades may not have the physical space to add them. Realistic cost and space constraints must be considered.

OSHA Regulations

OSHA mandates that all equipment used to dispense flammable liquids, including gasoline, be listed by a nationally-recognized testing laboratory. At present, no laboratory has listed a complete fuel dispenser system for use with fuel containing any ethanol level over 10 percent. While various components of a new fuel dispenser system are listed for use with E85, no entire system is so listed, which creates some potential compliance questions with OSHA regulations.

EPA UST Regulations

EPA regulations mandate that underground storage tanks (UST) and connected underground piping must be compatible with the liquid being stored. Fuels that are not compatible with the underground storage system are in violation of EPA rules and could lead to product releases.

Underground storage tanks and piping do exist that are compatible with all levels of ethanol up to 100 percent. However, this does not necessarily apply to the entire tank and piping infrastructure in the ground today. Underground storage tanks can be over 30 years old and still function effectively with current blends. However, 30 years ago, the manufacturers of these older tanks did not anticipate that they would be used with any level of ethanol over 10 volume percent. Additionally, most underground tanks that were manufactured even 20 years ago were only made to accommodate up to 10 volume percent ethanol in the gasoline. These tanks are ubiquitous and may pose a problem when attempting to raise the level of ethanol in gasoline. Research is ongoing to determine the extent of these issues and how they might be addressed.

States can choose to demonstrate compatibility pursuant to EPA regulations in various ways. States may require a listing for the tank and piping from a nationally-recognized testing laboratory such as Underwriters Laboratory (UL), or they can require a manufacturer‘s warranty or certification to accompany the underground storage tank and piping which certifies its compatibility with the substance stored. However, UL has explicitly stated they will not retroactively list products, and manufacturers have understandably given strong indications that they will not retroactively warranty their products for fuels which they were not built to handle.

UST Leak Detection Equipment

Existing leak detection systems for underground storage tanks may also prove a challenging obstacle to reconcile with increased ethanol blends. With E10 blends, phase separation occurs with 0.5 percent water, allowing excess water to be detected relatively quickly. However, with higher levels of ethanol, larger and larger quantities of water can be absorbed into the fuel before phase separation occurs. This appears to challenge the ability of automatic tank gauges (ATG) to detect water intrusion into the tank. ATGs and other leak detection equipment must be proven to work effectively with ethanol blends over 10 volume percent to prevent groundwater and fuel contamination.

Fire Codes

Fire codes, published by the International Code Council (ICC) and National Fire Prevention Association (NFPA), also have mandates in place for safe storage and dispensing of fuels. These fire codes are generally adopted in part or in full by authorities having jurisdiction (AHJs) and must be consulted before introduction of new fuels to existing infrastructure. NFPA and ICC require third-party listings for all underground tanks and piping for the liquids being stored. They also require listings for dispenser equipment. While these codes are able to be waived by AHJs, it cannot be assumed that they will be waived when new fuels are introduced. Codes in place are enforceable and must be adhered to as such. A waiver from these fire codes will not waive the potential liability associated with an equipment failure while storing and/or dispensing gasoline containing the higher levels of ethanol. Further, while an AHJ can waive the certain requirements in the fire codes, they cannot waive the OSHA requirements identified in the section on OSHA above.

Vapor Recovery

The relevance of Stage I and II concerns regarding the pending waiver is that the California Air Resources Board (CARB) vapor recovery program requires that "vapor recovery systems and components shall be compatible with any and all fuel blends in common use in CA and approved for use as specified in 13CCR§2260 et seq." Presently, there are no vapor recovery systems or equipment certified by CARB to handle or dispense any gasoline containing more than 10 volume percent ethanol.

G. OTHER

1. Comments on Commingling of RBOB and Conventional Gasoline

Background - We understand that EPA's current interpretation of 40 CFR 80.78(a)(5) and (7) is that this regulatory section prohibits the addition of ethanol to a commingled mixture of RBOB and conventional gasoline (or "CBOB" blendstock material). Consider Scenario #1 – for example, if a terminal were to add a batch of RBOB to a tank of conventional gasoline (or to a tank of CBOB) before sending the tank's contents to the terminal rack for ethanol addition, this commingling sequence is prohibited by 80.78(a)(5) and (7) according to EPA's interpretation. However, it's clear that the commingled ethanol-blended mixture is allowed if alternatively the operation were conducted in a slightly different order -- i.e., Scenario #2 wherein we (1) add ethanol to the RBOB separately, (2) add ethanol to the CG (or to the CBOB) separately, followed by (3) commingling the finished ethanol-blended RFG with the finished ethanol-blended CG in the truck compartment.

Both Scenario #1 and Scenario #2 result in an identical mixture residing in the truck compartment. It is only the sequence of the commingling plus ethanol addition that differs between the two scenarios. The existing regulatory prohibitions put form over substance since our examplel provides the exact same product into the truck, and thus to the consumer.

NPRA's Proposal - NPRA proposes that the prohibitions in 80.78(a)(5) and (7) be appropriately changed to allow Scenario #1 -- i.e., allow RBOB to be added to a tank of CG (or a tank of CBOB blendstock material) before the addition of ethanol at the terminal rack for sale in a conventional gasoline market. With respect to regulatory rigor for Scenario #1, it's important to note where the blending activities take place (all within a single terminal) and when they take place (all before the product leaves the terminal). This "single terminal" aspect allows tight control of the operation, as well as simple recordkeeping.

The additional flexibility being requested here would be most helpful in two areas: (1) achievement of the mandated renewable fuel mandates in RFS1, and the soon to be promulgated RFS2, and (2) help in relieving distribution and supply issues that occur unexpectedly, as well as during natural disasters such as during hurricane season.

2. Comments on Additional Flexibility for RVP Waiver

NPRA proposes that EPA provide for conventional gasoline the blending flexibility EPA provides for reformulated gasoline (RFG). EPA regulations allow retailers to sell non-ethanol-blended RFG that has been combined with ethanol-blended RFG under certain conditions ("commingling"). Providing this flexibility for conventional gasoline would provide flexibility while retail stations transition to ethanol-blended gasoline in the summer and transition out of ethanol-blended gasoline when there may be an ethanol shortage in a given area.

Under EPA's RVP regulations, in order for companies to qualify for the one-pound (psi) RVP allowance ("RVP waiver"), gasoline must contain 9% to 10% ethanol by volume. If blending facilities are completed during the VOC season, retail tanks will already contain non-ethanol-blended conventional gasoline (CG) that cannot be blended with ethanol-blended gasoline and still meet this 9 to 10 vol% ethanol requirement. Companies basically have two choices if they wish to begin blending ethanol during the VOC season: either pump out every single service station tank before delivering the first load of ethanol blended gasoline, thereby avoiding the "transition," or in special situations perhaps prepare a boutique low RVP base gasoline for blending such that the local vapor pressure standard is not exceeded after the ethanol is blended. Both of these options have significant supply implications. Thus, there is a need for EPA to allow commingling of ethanol-blended gasoline with non-ethanol blended gasoline without requiring that the gasoline contain 9-10 vol% ethanol. Thus, we request that EPA allow commingling for conventional gasoline.

Specifically, NPRA requests that EPA amend the current commingling rule at 40 CFR 80.78. Under this regulation, retail outlets would be allowed to sell non-ethanol-blended gasoline (meeting the area's RVP requirements) which has been combined with ethanol-blended gasoline (meeting the area's RVP requirements after allowing for a 1 psi RVP waiver) under certain conditions, which are similar to those for blending ethanol-blended RFG with non-ethanol-blended RFG.

- The retailer must provide evidence that each batch of gasoline that has been combined was in compliance with the specific RVP requirement for the area prior to blending with ethanol.

- The retailer must notify EPA prior to combining the gasoline and identify the exact location of the retail outlet and specific tank in which the gasoline is to be combined.
- The retailer must retain, and, upon request by EPA, make available for inspection, product transfer documentation accounting for all gasoline received at the retail outlet.
- Retailers are prohibited from combining the area's summertime RVP-controlled gasoline with non-summertime RVP-controlled gasoline between June 1 and September 15.

Retailers would also be limited with regard to the frequency with which batches of non-ethanol-blended gasoline may be combined with ethanol-blended gasoline. Retailers may combine such batches of gasoline a maximum of two periods between May 1 and September 15. Each period may be no more than ten consecutive calendar days.

3. The RFS2 regulations should include additional reminders that ethanol shall be denatured.

The proposed definition for "renewable fuel" in 80.1401 clearly states that ethanol shall be denatured. This should be repeated in other places, such as 80.1426, 80.1428, 80.1460, and 80.1466.

H. TECHNICAL CORRECTIONS

1. 80.1407 should be edited to exclude exported diesel from the RVO.

Exported gasoline is excluded at proposed 80.1407(d)(5). Exported diesel should also be explicitly excluded.

Section 80.1407 details which fuels are included and which are excluded from an obligated party's obligation. Consistent with EISA and the RFS1 rules, these provisions exclude exported gasoline from the obligation. In an apparent oversight, however, section 80.1407 fails to exclude exported distillate fuels from the obligation. EISA requires EPA to exclude such fuel from an obligated party's obligation, as EISA is limited to transportation fuels used in the United States.

For example, a new paragraph "(g)" could be added at the end of 80.1407: "Diesel fuel exported for use outside of the 48 United States, Hawaii, Alaska, the Commonwealth of Puerto Rico, the U.S. Virgin Islands, Guam, American Samoa, and the Commonwealth of the Northern Marianas is not included in the volume of diesel produced or imported used to calculate a party's renewable volume obligation under paragraph (a) of this section."

In addition, similar to the provisions that apply to gasoline fuels, EPA should include provisions in this section specifying which types of distillate fuels are included and excluded from the obligation. And, EPA should clarify that gasoline and distillate volumes produced at transmix facilities do not incur an obligation since such fuel was already accounted for and is part of the obligation of refiners and importers. To not exclude such fuels produced at transmix facilities would be to double-count such volumes.

2. The renewable fuel standard equations must be calculated carefully.

The proposed equations for the calculation of the annual renewable fuel standard percentages are at 80.1405(d). The denominators should be EIA projections of gasoline and diesel volumes excluding renewable fuels. This is clear from 80.1405(c):

> EPA will base the calculation of the standards on information provided by the Energy Information Administration regarding projected gasoline and diesel volumes and projected volumes of renewable fuels expected to be used in gasoline and diesel blending for the coming year.

In the four "Std" equations in this section, EPA subtracts EIA's projected renewable fuel usage from EIA's projected gasoline and diesel demand. Since EPA is actually mandating the minimum renewable volumes for the year in question, it should in fact only use the EIA renewable projections if they are larger than the EISA-mandated renewable volumes. In the cases where EIA's projected renewable volumes are less than the RFV_i volumes which will be mandated, the EISA-mandated volumes should be used.

Since the RFS2 regulations will not be in effect in 2010 and the small refinery and small refiner exemptions expire at the end of 2010, the "Std" equations only apply for years 2011 and later. As a result, the "GE" terms for exempt small refineries and small refiners should be dropped from the "Std" equations.

APPENDIX A

Appendix A (see attachment) includes comments submitted by NPRA to EPA in July 2009 on the petition to increase the allowable ethanol content of gasoline to 15 volume percent. See docket document EPA-HQ-OAR-2009-0211-2550.

APPENDIX B

Appendix B includes comments on lifecycle GHG analysis.

Comments on EPA RFS2 Program LCA

EPA has undertaken a very thorough analysis of the life-cycle GHG emissions associated with biofuels and petroleum fuels. In general we find the technical tools and procedures to be sound. However, in several cases the scenario parameters or model inputs bias the results. Examples include: use of 2022 as evaluation year for biofuels facilities, use of 100 year time horizon and several assumptions regarding cellulosic ethanol.

Land-Use Change

We strongly support EPA's inclusion of indirect land-use change (iLUC) in biofuel GHG LCA. EISA requires that indirect emissions associated with land use change be included in the lifecycle assessment and EPA's analysis is consistent with the intent of the legislation. Indirect land-use has been identified as a significant GHG emission source related to increased biofuel production by a number of researchers [1-5]. Including iLUC in the assessment of greenhouse gas (GHG) emissions from biofuels is critical if GHG reduction goals are to be achieved. The projected magnitude of iLUC emissions are large and therefore, notwithstanding the technical uncertainty, should be part of both near and long term quantification of biofuel GHG emissions. To that end, we support:

- Assessment of global iLUC emissions using the best available science, and continued refinement of this assessment as science and experience progress.
- Incorporation of iLUC emissions in regulations pertaining to biofuel GHG emissions by practical methodologies that can be applied in the near term.

Carbon stocks in natural ecosystems are much larger than carbon in the atmosphere. Tropical ecosystems alone store 340 billion tonnes of carbon, equivalent to more than 40 times the annual anthropogenic emissions from fossil fuel combustion [1]. Conversion of natural lands, particularly forest, to productive cropland releases large amounts of CO_2 into the atmosphere due to burning, clearing, and decomposition of plant biomass leading to a loss of soil carbon.

Land use change (LUC), both direct conversion to biomass production and indirect conversion through displacement effects, is a complex technical issue but the results to date indicate that land use is a significant portion of the GHG impact from many biofuel production pathways. Gnansounou, et al. [6] recommend "fixing the system boundaries at the world-wide level (commodity-trading countries) for economic modeling of iLUC". Additionally they indicate that "collaborative work is needed at the international level in order to develop a common and appropriate methodology to account for iLUC."

In order to analyze iLUC the global response to changes in US policy need to be evaluated. We endorse the use of FASOM and FAPRI to model iLUC. These models are detailed tools with a high level of detail and data validation. FASOM has been used to model US agricultural GHG for many years. Linking the models is appropriate and allows the analytical strengths of both models to be utilized. We also support examination of GTAP as an alternative modeling platform with global scope. We agree with use of satellite (MODIS) data to estimate type of land converted internationally but recommend use of a larger dataset than just three years.

Time Horizon

The time horizon over which GHG emissions from time-dependent sources like iLUC are accounted can lead to differences in the carbon intensity applied to the fuel. The use of a discount factor can lead to further differences. Shorter time periods give more weight to the known, more immediate, effects of carbon release from clearing, burning, and loss of soil sequestration. Use of longer time periods gives more weight to activities that are much more uncertain. The 100 year period is a poor choice because: 100 years is much longer than the life of individual biofuel plants, there is considerable uncertainty about benefits in the out years of a 100-year period and benefits are credited that occur well beyond the period covered by the current regulation. A longer time horizon also introduces a need for discounting emissions, but there is no clear rationale for selecting an appropriate discount rate. A time period of 30 years or less and simple averaging is a pragmatic approach that ensures that anticipated GHG benefits from the regulation are received. A thirty-year analysis period with no discounting is also consistent with recent CARB LCA. Not accounting for the integrated decay of GHG emissions can lead to under-prediction of the GHG emissions associated with sources with iLUC emissions. A recent paper outlines a simple approach to account for radiative decay of GHG in the atmosphere [5].

Biofuel Analysis Year

EPA's analysis evaluates the incremental impact of renewable fuel facilities built in 2022. Considerable improvement in plant and agricultural efficiency is assumed compared to current conditions. This procedure underestimates GHG emissions from biofuel facilities before 2022 and introduces uncertainty through use of projected factors instead of validated data. It would be better to base the analysis on a near-term date using actual data and to then update as needed if data indicates improvement.

Cellulosic Ethanol

There is very large uncertainty in projected future GHG emissions of cellulosic ethanol due to the range in potential feedstocks and chemicals as well as yields and co-products, as well as the lack of any existing commercial operation. EPA has projected large improvements in performance to the 2022 time frame, but it is not clear these improvements will be realized. Although frequently ignored, GHG emissions associated with enzyme production for cellulosic ethanol can be much larger than corn ethanol and a can be significant fraction of cellulosic ethanol GHG [7]. While continued research may lead to the development of low dose high activity enzyme systems there is considerable uncertainty over the performance of future systems. Outlining current and possible future performance and tracking the progress over time would provide a better measurement of the LCA performance of cellulosic ethanol.

The RFS analysis projects large GHG credits for electricity co-generation in cellulosic ethanol facilities. Use of biomass to generate electricity in general provides much larger GHG benefits than fuel conversion. Renewable power from biomass will be required or subsidized in the future. Thus the alternative use of biomass as a direct feedstock for electric power generation should also be considered.

EPA's analysis projects significant soil carbon benefits due to cellulosic ethanol and these have a significant impact on the results. No-till farming with related carbon benefits is tied to corn stover collection for ethanol. No-till farming is being introduced today and therefore should not be tied directly to stover collection. Under many scenarios corn stover could lead to soil carbon depletion instead of accumulation. Significant soil carbon benefits are also projected for switchgrass use but these benefits will not occur if farming practices rotate.

The spreadsheet on cellulosic ethanol indicates that cellulosic ethanol causes a large reduction in GHG emissions from international livestock production. The mechanism for such a reduction is not clear.

References:

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